BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF: LOUISVILLE GAS AND ELECTRIC COMPANY TRIMBLE COUNTY, KENTUCKY TITLE V/PSD AIR QUALITY PERMIT # V-02-043 REVISIONS 2 AND 3 ISSUED BY THE KENTUCKY DIVISION FOR AIR QUALITY	)	PETITION NO. IV-2008-3

ORDER RESPONDING TO ISSUES RAISED IN APRIL 28, 2008 AND MARCH 2, 2006 PETITIONS, AND DENYING IN PART AND GRANTING IN PART REQUESTS FOR OBJECTION TO PERMIT

On April 28, 2008, and March 2, 2006, the United States Environmental Protection Agency (EPA) received petitions from Save the Valley, Sierra Club, and Valley Watch (Petitioners) pursuant to Section 505(b)(2) of the Clean Air Act ("CAA" or "Act"), 42 United States Code (U.S.C.) § 7661d(b)(2) (the March 2, 2006, petition is referred to as "Petition 1" and the April 28, 2008, petition is referred to as "Petition 2"). Both Petitions request that EPA object to the merged CAA construction/operating permit issued by the Kentucky Division for Air Quality ("KDAQ" or "Division") on January 4, 2006 (Revision 2), and February 29, 2008 (Revision 3), respectively, to Louisville Gas and Electric Company (LG&E). The permits are for construction of a new 750 megawatt pulverized coal-fired boiler (and other associated modifications) at the Trimble County Generating Station located in Bedford (Trimble County), Kentucky. Permit #V-02-043 is a merged CAA prevention of significant deterioration (PSD) construction permit and a CAA title V operating permit issued pursuant to Kentucky's Administrative Regulations (KAR) at 401 KAR 52:020 (title V regulations) and 51:017 (PSD regulations).

On September 10, 2008, EPA issued a "Partial Order Responding to March 2, 2006, Petition and Denying in Part and Granting in Part Request for Objection to Permit Revision 2." In the September 2008 Order, EPA explained that some issues raised in Petition 1 were affected by Permit Revision 3 and also discussed in Petition 2. At this time, EPA is addressing all the remaining issues identified by Petitioners in Petitions 1 and 2.

This Order contains EPA's response to Petitioners' request that EPA object to the permit on the basis that: (1) public participation procedures were not adequate; (2) the permit fails to include requirements for addressing greenhouse gases; (3) BACT for nitrogen oxides (NO_x) and sulfur dioxide (SO_2) is not adequate; (4) BACT for the auxiliary boiler and emergency diesel generator are not adequate; (5) BACT for support operations is not adequate; (6) BACT for particulate matter (PM) and particulate matter with a diameter less than ten micrometers (PM_{10}) are not adequate; (7) BACT for sulfuric acid mist (SAM) is not adequate; (8) the permit fails to consider particulate matter with a diameter less than 2.5 micrometers ($PM_{2.5}$); (9) the permit fails to express limits in an adequate manner; (10) BACT analyses did not include clean fuels; (11) the permit lacks a maximum achievable control technology (MACT) determination for mercury and other hazardous air pollutants (HAP); (12) the SAM limits are not enforceable (compliance assurance monitoring concerns); and (13) the permit improperly relies on manufacturer specifications that are not included in the permit, does not identify test methods, and additional concerns regarding netting.

Based on a review of Petitions 1 and 2 and other relevant materials, including the LG&E permit and permit record, and relevant statutory and regulatory authorities, I grant in part and deny in part the Petitions requesting that EPA object to the LG&E permit. I grant on issues 4 and 8 above.

I. STATUTORY AND REGULATORY FRAMEWORK

Section 502(d)(1) of the Act, 42 U.S.C. § 7661a(d)(1), calls upon each state to develop and submit to EPA an operating permit program to meet the requirements of title V of the CAA. The Commonwealth of Kentucky[1] originally submitted its title V program governing the issuance of operating permits in 1993, and EPA granted full approval on October 31, 2001. 66 *Fed. Reg.* 54,953. The program is now incorporated into Kentucky's Administrative Regulations at 401 KAR 52:020. All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emission limitations and other conditions as necessary to assure compliance with applicable requirements of the CAA, including the requirements of the applicable State Implementation Plan (SIP). CAA §§ 502(a) and 504(a), 42 U.S.C. §§ 7661a(a) and 7661c(a).

The title V operating permit program does not generally impose new substantive air quality control requirements (which are referred to as "applicable requirements"), but does require permits to contain monitoring, recordkeeping, reporting, and other conditions to assure sources comply with existing applicable requirements. 57 *Fed. Reg.* 32,250, 32,251 (July 21, 1992) (EPA final action promulgating Part 70 rules). One purpose of the title V program is to enable the source, EPA, states, and the public to better understand the applicable requirements to which the source is subject and whether the source is complying with those requirements. Thus, the title V operating permit program is a vehicle for ensuring that existing air quality control requirements are appropriately applied to facility emission units and that compliance with these requirements is assured.

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[1] The Commonwealth of Kentucky Environmental and Public Protection Cabinet (Kentucky Cabinet), which submitted the title V program, oversees the Kentucky Division for Air Quality (KDAQ) which is the permitting authority for title V and PSD permits in Kentucky.

For a major modification of a major stationary source,[2] applicable requirements include the requirement to obtain a preconstruction permit that complies with applicable new source review requirements (e.g., PSD). Part C of the CAA establishes the PSD program, the preconstruction review program that applies to areas of the country, such as Trimble County, that are designated as attainment or unclassifiable for National Ambient Air Quality Standards (NAAQS). CAA §§ 160-169, 42 U.S.C. §§ 7470-7479. New Source Review, or "NSR," is the term used to describe both the PSD program as well as the nonattainment NSR program (applicable to areas that are designated as nonattainment with the NAAQS). In attainment areas (such as Trimble County), a major stationary source may not begin construction or undertake certain modifications without first obtaining a PSD permit. CAA § 165(a)(1), 42 U.S.C. § 7475(a)(1). The PSD program analysis must address two primary and fundamental elements before the permitting authority may issue a permit: (1) an evaluation of the impact of the proposed new or modified major stationary source on ambient air quality in the area, and (2) an analysis ensuring that the proposed facility is subject to BACT for each pollutant subject to regulation under the PSD program. CAA § 165(a)(3),(4), 42 U.S.C. § 7475(a)(3), (4); *see also* 401 KAR 51:017 (Kentucky's PSD program). The BACT analysis is further discussed in Section III.B. of this Order, below.

EPA has promulgated two largely identical sets of regulations to implement the PSD program. One set, found at 40 Code of Federal Regulations (CFR) § 52.21, contains EPA's own federal PSD program, which applies in areas without a SIP-approved PSD program. The other set of regulations, found at 40 CFR § 51.166, contains requirements that state PSD programs must meet to be approved as part of a SIP. In 1989, EPA approved Kentucky's PSD rules into the SIP as meeting these requirements. 54 *Fed. Reg.* 36,307 (September 1, 1989); *see also* 40 CFR § 52.931.[3] Thus, the applicable requirements of the Act for major modifications at major sources, such as at LG&E, include the requirement to comply with PSD requirements under the Kentucky SIP. *See, e.g.*, 40 CFR § 70.2.[4] In this case, the Commonwealth's rules require a

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[2] The proposed addition of a new 750 megawatt coal-fired boiler at LG&E is considered a "major modification," consistent with the definition of "major modification," in 401 KAR 51:001 § 1(116). The existing LG&E facility is a major stationary source, as that term is defined in 401 KAR 51:001 § 1(120).

[3] On February 10, 2006, EPA proposed to approve changes made to Kentucky's New Source Review (NSR) program consistent with EPA's 2002 NSR Reform Rules. 71 *Fed. Reg.* 6,988 (February 10, 2006). On July 11, 2006, EPA took final action approving Kentucky's NSR program incorporating changes made pursuant to EPA's 2002 NSR Reform Rules. 71 *Fed. Reg.* 38,990 (July 11, 2006). Kentucky's revisions to its NSR program consistent with NSR reform, became effective under Kentucky law on July 14, 2004, and were submitted to EPA as a SIP revision for approval in September 2004. For further information about rules incorporated into the Kentucky SIP, see http://www.epa.gov/region4/air/sips/ky/kytoc.htm.

[4] Kentucky defines "federally applicable requirement" in relevant part to include a "federally enforceable requirement or standard that applies to a source." 401 KAR 52:001 § 1(15). Kentucky further defines "federally enforceable requirement," as "[s]tandards or requirements in the state implementation plan (SIP) that implement the relevant requirements of the Act, including revisions to that plan promulgated at 40 CFR Part 52." 401 KAR 52:001 § 1(34).

source to apply for a PSD permit which is then incorporated into the existing title V permit as a revision to the title V permit. 401 KAR 52:020.

Under section 505(a), 42 U.S.C. § 7661d(a), of the CAA and the relevant implementing regulations (40 CFR § 70.8(a)), states are required to submit each proposed title V permit, and certain revisions to such permits, to EPA for review. Upon receipt of a proposed permit, EPA has 45 days to object to final issuance of the permit if it is determined not to be in compliance with applicable requirements or the requirements of title V. 40 CFR § 70.8(c). If EPA does not object to a permit on its own initiative, section 505(b)(2) of the CAA provides that any person may petition the Administrator, within 60 days of the expiration of EPA's 45-day review period, to object to the permit. 42 U.S.C. § 7661d(b)(2), *see also* 40 CFR § 70.8(d). In response to such a petition, the CAA requires the Administrator to issue an objection if a petitioner demonstrates that a permit is not in compliance with the requirements of the CAA. 42 U.S.C. § 7661d(b)(2); *see also* 40 CFR § 70.8(c)(1), *New York Public Interest Research Group (NYPIRG) v. Whitman*, 321 F.3d 316, 333 n.11 (2nd Cir. 2003). Under section 505(b)(2), the burden is on the petitioner to make the required demonstration to EPA. *Sierra Club v. Johnson*, 541 F.3d. 1257, 1266-1267 (11th Cir. 2008); *Citizens Against Ruining the Environment v. EPA*, 535 F.3d 670, 677-678 (7th Cir. 2008); *Sierra Club v. EPA*, 557 F.3d 401, 406 (6th Cir. 2009) (discussing the burden of proof in title V petitions); *see also NYPIRG*, 321 F.3d at 333 n.11. If, in responding to a petition, EPA objects to a permit that has already been issued, EPA or the permitting authority will modify, terminate, or revoke and reissue the permit consistent with the procedures set forth in 40 CFR §§ 70.7(g)(4) and (5)(i) - (ii), and 40 CFR § 70.8(d).

Where a petitioner's request that the Administrator object to the issuance of a title V permit is based in whole, or in part, on a permitting authority's alleged failure to comply with the requirements of its approved PSD program (as with other allegations of inconsistency with the Act) the burden is on the petitioners to demonstrate that the permitting decision was not in compliance with the requirements of the Act, including the requirements of the SIP.[5] Such requirements, as EPA has explained in describing its authority to oversee the implementation of the PSD program in states with approved programs, include the requirements that the permitting authority (1) follow the required procedures in the SIP; (2) make PSD determinations on reasonable grounds properly supported on the record; and (3) describe the determinations in enforceable terms. *See, e.g.*, 68 *Fed. Reg.* 9,892, 9,894-9,895 (March 3, 2003); 63 *Fed. Reg.* 13,795, 13,796-13,797 (March 23, 1998). EPA has approved the PSD programs into the SIPs of most states, including the Commonwealth of Kentucky, and as the permitting authority, Kentucky has substantial discretion in issuing PSD permits. Given this, in reviewing a PSD permitting decision, EPA will not substitute its own judgment for that of Kentucky. Rather, consistent with the decision in *Alaska Dep't of Envt'l Conservation v. EPA*, 540 U.S. 461 (2004), in reviewing a petition to object to a title V permit raising concerns regarding a state's PSD

[5] The appeal of federal PSD permits issued pursuant to the federal regulations at 40 CFR § 52.21 is governed by the regulations at 40 CFR § 124.19, and authority to review such permits rests exclusively with the Environmental Appeals Board (EAB). Because of the exclusive authority of the EAB in this area, the Administrator has declined to review the merits of a federal PSD permit in the context of a petition to review a title V permit. *See, e.g., In re Kawaihae Cogeneration Project,* Petition No. 0001-01-C (Order on Petition) (March 10, 1997).

permitting decision, EPA generally will look to see whether the Petitioner has shown that the state did not comply with its SIP-approved regulations governing PSD permitting or whether the state's exercise of discretion under such regulations was unreasonable or arbitrary.[6] *See, e.g., In re East Kentucky Power Cooperative, Inc.* (Hugh L. Spurlock Generating Station) Petition No. IV-2006-4 (Order on Petition) (August 30, 2007); *In re Pacific Coast Building Products, Inc.* (Order on Petition) (December 10, 1999); *In re Roosevelt Regional Landfill Regional Disposal Company* (Order on Petition) (May 4, 1999).[7]

II. BACKGROUND

Existing Facility

The LG&E facility in Trimble County, Kentucky, began construction on its existing 500 megawatt (MW) pulverized coal-fired boiler in the late 1970s (Unit 1). The facility has undergone a series of modifications since then, adding not only the support facilities for the original 500 MW boiler, but also, six 160 MW simple cycle natural gas combustion turbines (Units 25-30) in approximately 2001. The existing facility also includes support structures such as a natural draft cooling tower; coal/limestone/ash/gypsum material handling equipment; three auxiliary boilers; an emergency diesel generator; and fuel oil storage tanks. Unit 1 and Units 25-30 previously went through PSD permitting prior to construction. A draft title V permit for the facility was first issued in December 1997, followed by several permit changes eventually resulting in Revision 2. Kentucky issued the title V permit Revision 2 on January 4, 2006, and Revision 3 on February 29, 2008. *See* LG&E Permit Revision 3 Statement of Basis (SOB Revision 3) (July 26, 2007). Both revisions are at issue in the instant Petitions.[8]

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[6] In determining the appropriate standard of review to apply to the review of federal PSD permit determinations in a petition to object to a title V permit, the standard of review applied by the EAB in reviewing the appeals of federal PSD permits provides a useful analogy. The standard of review applied by the EAB in its review of federal PSD permits is discussed in numerous EAB orders as the "clearly erroneous" standard. *See, e.g., In re Prairie State Generation Company,* 13 E.A.D. ___, PSD Appeal No. 05-05, slip op., 2006 EPA App. LEXIS 38 (EAB, August 24, 2006); *In re Kawaihae Cogeneration,* 7 E.A.D. 107, 114 (EAB, April 28, 1997). In short, in such appeals, the EAB explained that the burden is on a petitioner to demonstrate that review is warranted. Ordinarily, a PSD permit will not be reviewed by the EAB unless the decision of the permitting authority was based on either a clearly erroneous finding of fact or conclusion of law, or involves an important matter of policy or exercise of discretion that warrants review.

[7] Section II of Petition 2, "Petition Standard of Review," describes the Petitioners' view of the applicable standard of review. This section of the Petition raises no requests for objection. EPA's articulation of its view on the standard of review in title V petitions is not intended to either agree or disagree with Petitioners' views.

[8] In evaluating the remaining issues in both Petitions, EPA considered the terms of the current permit for the facility (Revision 3). Permit citations are provided for Revision 3 unless the particular citation at issue was different in Revision 2 than Revision 3. For purposes of clarity in this Order, the permits are referred to by revision.

Permit History

In December 2004, LG&E submitted a PSD permit application to KDAQ to include into its title V permit, a PSD construction permit to undertake a major modification to construct a new 750 MW net nominal generating unit that would utilize supercritical pulverized coal (Unit 31).[9] Ancillary equipment for this new unit includes a new linear mechanical draft cooling tower, a coal blending facility, dust collectors and dust suppression equipment on material handling operations, an ash barge loading system/fly ash silos, an auxiliary steam boiler, a backup diesel generator, and an emergency diesel fire water pump engine. The construction of new Unit 31 is also expected to increase utilization of the existing natural draft cooling tower on Unit 1, various material handling equipment, the three auxiliary boilers, emergency diesel generator, and fuel oil storage tanks.

In late 2004, and separate from the PSD application, LG&E submitted a minor permit revision application to KDAQ for a voluntary creditable decrease in emissions for nitrogen oxides (NO_x) and sulfur dioxide (SO_2) for Unit 1. The creditable decreases were requested to net against the anticipated future increases in emissions from the new Unit 31 for PSD purposes. In January 2005, KDAQ approved the minor permit revision to reduce the NO_x and SO_2 emission limits for Unit 1 (Revision 1, minor modification).

The final draft Revision 2 combined PSD/title V permit for construction of new Unit 31 was opened for public notice and comment in July 2005. Minor changes were made to the permit following public comment and the final Revision 2 Permit was issued on January 4, 2006. The Petitioners administratively appealed the issuance of the Revision 2 Permit by KDAQ, which resulted in a Final Order by the Secretary of the Kentucky Environmental Protection and Public Health Cabinet on September 28, 2007, granting certain claims and denying others. On October 26, 2007, KDAQ issued a revision entitled, "Revision 2 Administrative Amendment," which involved revisions to the permit in response to the Secretary's Final Order. In January 2008, KDAQ further revised the permit (Revision 3).

In issuing Revision 2, KDAQ concluded that the proposed major modifications would result in a significant net increase in emissions of particulate matter (PM) and particulate matter with a diameter of less than ten micrometers (PM_{10}), carbon monoxide (CO), volatile organic compounds (VOC), fluorides, and sulfuric acid mist (SAM). Due to the voluntary creditable decreases in emissions of NO_x and SO_2 at Unit 1, which were approved in Revision 1, KDAQ concluded that the new Unit 31 was not subject to major PSD review for NO_x and SO_2. As presented for Revision 2, the design of Unit 31 involved a suite of control technology including: selective catalytic reduction (SCR); pulse jet fabric filters (PJFF) and hydrated lime injection; wet flue gas desulfurization (WFGD); wet electrostatic precipitator (WESP). These control technologies, in addition to the construction of the new linear mechanical draft cooling tower and other operational limits, were determined by KDAQ as sufficient for the facility to meet BACT requirements that resulted from KDAQ's PSD review of the proposed major modification. KDAQ SOB Revision 2.

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[9] In some permitting information, Unit 31 is also referred to as Unit 2. In this Order, we reference Unit 31 or "the new unit."

On February 13, 2007, LG&E submitted an application for a significant revision to amend the permit to account for permitting redesigns. KDAQ SOB Revision 3 at 1. As part of this revision, the permit was modified to include additional control technology for Unit 31 – a dry electrostatic precipitator (DESP) and powdered activated carbon (PAC) injection and hydrated lime injection. The DESP is intended to ensure that the saleable fly ash is captured prior to potential contamination due to PAC injection which is for mercury control. KDAQ SOB Revision 3 at 2. In addition to these changes, Revision 3 also included permitting changes for the following other changes to operations and/or design at the facility: (1) Unit 32 (auxiliary boiler) changes including increased hours of operation and use of ultra low sulfur fuel; (2) Unit 33 (emergency generator) changes including use of ultra low sulfur fuel and changes to hours of operation; (3) the elimination of three existing auxiliary boilers (Units 7-9) and the emergency diesel firewater pump; (4) the addition of material handling silos (waste ash, hydrated lime and PAC); (5) movement of proposed conveyer transfer points; (6) new conveyer transfer points; (7) an increase in length of haul road; and (8) ash transfer design changes. KDAQ SOB Revision 3 at 2-3. As a result of these changes, KDAQ also reviewed the previous PSD analysis done for the facility and made some changes to emission calculations for the netting associated with Unit 31 (for NO_x and SO_2) as well as revised calculations for the PM emissions from the linear mechanical draft cooling tower (Unit 41). Despite the changes, KDAQ concluded that the facility was still able to use netting to avoid PSD review for NO_x and SO_2 associated with the addition of Unit 31. KDAQ SOB Revision 3 at 3.

At this time, LG&E is engaged in construction of Unit 31 and the associated design changes necessary at the facility to support the new unit. In addition, in mid-January 2009, KDAQ proposed changes to Revision 3 to the permit to respond to EPA's September 10, 2008, Order which granted two petition issues. KDAQ did not receive comments from Petitioners on this revision. On April 21, 2009, KDAQ issued a proposed permit (Revision 4 – although it is not identified by KDAQ in that manner). On June 5, 2009, EPA Region 4 objected to the permit on two grounds. First, that KDAQ "must undertake a Section 112(g) analysis for all hazardous air pollutants with respect to Unit 31 in order to comply with all applicable Clean Air Act requirements." Second, that the startup/shutdown limits added to the permit must be rewritten to more accurately reflect what is presented in the Statement of Basis. EPA did not object to the substance of KDAQ's revised analysis for startup and shutdown (which was required as part of the September 10, 2008, Order). Consistent with the CAA and applicable regulations, KDAQ has ninety days in which to revise the permit pursuant to the June 5, 2009, objection letter.

III. EPA DETERMINATIONS ON PETITIONS 1 AND 2

A. Petitioners' Claims Regarding Public Participation

Petitioners allege that EPA must object to the permit because KDAQ did not comply with applicable public participation requirements during the Revision 2 process in three primary ways. Petitioners allege that KDAQ (1) did not make the entire permit application or all supporting materials available to the Petitioners; (2) was unresponsive to Petitioners' requests for information during the public comment period – thus impacting public participation; and (3) failed to meaningfully extend the public comment period to correct its delays in providing information to Petitioners. Petition 1 at 6-7. Subsequent to Petition 1, a second public comment period was held for Revision 3 to the permit. Petitioners raised no new public participation concerns following the Revision 3 public comment process. For the reasons discussed below, the Petitions[10] are denied with regard to all public participation issues raised although EPA emphasizes the fundamental importance of public participation and strongly urges KDAQ to revise its procedures.

1. Failure to make entire permit file available and respond to requests for information during public comment period

Petitioners' allegations regarding KDAQ's failure to make the entire permit file available in a timely manner to the public during the public comment period involve three distinct assertions. First, the file viewed by Petitioners during the public comment period did not include a CD-ROM dated November 7, 2005, describing CO air quality monitoring data. Second, the minor permit modification applications (Revision 1), which involved the voluntary creditable decreases of NO_x and SO_2 emissions from Unit 1, were not included in the Revision 2 file. In addition, the file viewed by Petitioners during the public comment period did not include a startup/shutdown plan or operation and maintenance specifications. Third, the files were allegedly disorganized and Petitioners were not able to obtain in a timely manner copies of the relevant files for review.

a. CO air quality monitoring data

Petitioners' Claims. During the public comment period in July 2005, Petitioners sought to view the entirety of the permit file. Petition 1 at 7. In February 2006, as part of discovery during the administrative appeal of Permit Revision 2, KDAQ produced a CD-ROM with CO air quality monitoring data which was dated November 7, 2005. Petitioners claim that the permit record was flawed because it did not contain this CD-ROM. *Id.*

EPA's Response. During the permitting process for a facility like the LG&E facility, KDAQ typically receives a number of submittals from the permittee regarding, among other matters, air quality monitoring data. Petitioners presented no information explaining what the November 7, 2005, CD-ROM contained, whether it was related to Permit Revision 2, or even when it was submitted to KDAQ (i.e., whether it was a part of the permit application or submitted later). Further, Petitioners presented no information indicating that KDAQ relied on that CD-ROM to establish the CO limits or to perform any required analyses. The mere existence of a data set dated after draft permit issuance and the public comment period, with no information supporting its relevance to the decision, is not sufficient to demonstrate that KDAQ failed to comply with a requirement under the Act in issuing the permit. Additionally, Petitioners present no information suggesting that either KDAQ relied on this information in making a permit decision or that review of this information was necessary to meaningfully

[10] These public participation issues were raised in Petition 1, but reiterated in Petition 2. In this section, EPA is addressing all the public participation issues raised (the substance of which is discussed primarily in Petition 1). EPA uses the term "Petitions" because the issues were also referenced in Petition 2.

review the proposed project or permit. *See, e.g., In the matter of Pencor-Masada Oxynol, LLC*, Petition No. II-2000-07 (Order on Petition) (May 2, 2001) at 5 (denying an issue regarding public availability of certain documents).

In addition, we note that Petitioners have had a second opportunity through the Revision 3 changes, to provide KDAQ with any comments concerning the CO data contained in the CD-ROM to the extent that they believe it is pertinent to the permitting decision. Although Petitioners provided comments regarding CO to KDAQ during the Revision 3 public comment period, there is no mention of or reference to the data on the CD-ROM. Petitioners' Exhibit 1 at 16-17. For these reasons, Petitioners failed to demonstrate that the permit is not in compliance with the Act. As a result, the Petitions are denied as to this issue.

b. Permit file missing information such as minor revision applications, startup/shutdown plan, and operation and maintenance information

Petitioners' Claims. Petitioners sought to view the permit file (for Revision 2) at KDAQ offices in Frankfort, Kentucky and were provided with a box of documents. Petitioners allege that applications submitted by LG&E seeking the minor permit revision (Revision 1) involving the voluntary creditable decreases of NO_x and SO_2 emissions at Unit 1 were not included in the permit file for Revision 2. Petitioners further allege that the box did not include the startup/shutdown plan or operation and maintenance materials. Petition 1 at 8-9.

EPA's Response. KDAQ's public participation procedures for PSD and title V permits are found at 401 KAR 52:100. Consistent with Kentucky's PSD rules at 401 KAR 51:017 § 15, the federal public participation rules found at 40 CFR § 51.166(q) also apply. Federal title V rules found at 40 CFR § 70.7(h) also describe public participation procedures although Kentucky's rules are more detailed in their requirements than Section 70.7(h). In pertinent part, 401 KAR 52:100 § 8(1)(a-c), "Public Inspection of Documents," provides that Kentucky shall make available the permit application, the draft permit, and supporting materials. The federal rules further explain that the permitting authority shall "[m]ake available in at least one location in each region in which the proposed source would be constructed a copy of all materials the applicant submitted, a copy of the preliminary determination, and a copy or summary of other materials, if any, considered in making the preliminary determination." 40 CFR § 51.166(q).

Inclusion of a particular document in the permitting file depends in large part on whether the information at issue was relied upon by KDAQ in the permitting decision, and not available in any other documents provided to the public. The SOB for Revision 2 provides an explanation of the voluntary creditable decreases as well as information associated with that permit modification that was relevant to Revision 2.[11] KDAQ SOB Revision 2 at 3-7. In the Response to Comments (RTC) for Revision 2, KDAQ explained that "[a]ppropriate supporting materials

[11] The application for Revision 2 includes the netting calculations and provides significantly more information regarding the netting analysis for Unit 31 than did the minor modification application which did not include the netting analysis at Unit 31, but rather, just the decreases in emissions from Unit 1.

on reductions were provided to the public through the air permit application document, the Statement of Basis netting discussion, and minor permit revision applications supporting the creditable emission decreases…" KDAQ RTC Revision 2 at 13. Thus, according to KDAQ, the permitting record for Revision 2 included the information from the minor modification that KDAQ relied upon in evaluating Revision 2. Further, the netting issues were open for additional public comment as part of Revision 3 to the permit, and Petitioners did not raise any concerns regarding insufficient information at that time. For the reasons discussed above, Petitioners have not demonstrated that any information from the minor permit modification applications that was relied upon by KDAQ was not provided in the permitting record. Therefore, the Petitions are denied as to this issue.

With regard to the startup/shutdown plan, we note that in the September 10, 2008 EPA Order, we granted the objection in Petition 1 that the permit did not adequately address startup and shutdown emissions as part of the BACT analysis. Thus, the permit record now contains additional information regarding periods of startup and shutdown, and a new public comment period was held specifically on this issue. Petitioners did not submit comments to KDAQ on the most recent permit revisions regarding startup and shutdown. Thus, this issue appears resolved and is now moot.

With regard to the operation and maintenance information, Petitioners make a general assertion that "the operating and maintenance procedures and manufacturer's recommendations for the proposed unit's equipment" were "absent from the file." Petition 1 at 9. LG&E did include some specific operation and maintenance information for certain components as part of the 2004 Application (in Appendix E). Prevention of Significant Deterioration Construction Permit Application and Title V Operating Permit Application Trimble County Unit 2, Louisville Gas & Electric (December 1, 2004) (hereafter referred to as "2004 Application"). Petitioners do not explain what particular information was missing from the file. Further, as a general matter, at the time of issuance of a PSD permit, construction has not yet occurred. In general, companies may not have contracted for construction at the time the permit application is pending because many companies are reluctant to enter into binding contracts without a final preconstruction permit. Although the application and the permit specify the design of the affected units, there are often many manufacturers of the control technologies and other components such that inclusion of all operation and maintenance information in the permit record may not be practical. Petitioners do not demonstrate that the permit record lacked any required operation and maintenance information, and thus the Petition is denied on this issue.

For the above reasons, Petitioners fail to demonstrate that the permit is inconsistent with the Act. As a result, Petitions are denied as to the issues identified above.

c. KDAQ's files were disorganized, inhibiting onsite review; copies were not timely provided to Petitioners

Petitioners' Claims. Petitioners state that the file they received from KDAQ was "jumbled" and "disorganized;" that they had trouble identifying where the file could be viewed (which KDAQ office), which delayed viewing; that the onsite copier was broken; and when

Petitioners' requested copies of the permit file, the copies were provided during the third week of August 2005, two weeks after the close of the comment period. Petition 1 at 8.

EPA's Response. As a procedural threshold matter, Petitioners failed to raise any of these issues during the public comment period. Petitioners' Exhibit A to Petition 1 (Comments (Revised) on the Louisville Gas and Electric Company Proposed Coal-Fired Power Plant (August 9, 2005) at 3). The comment letter raises three public participation issues –that it was not clear when the public comment period began, that KDAQ failed to extend the public comment period, and that some information regarding SO_2 and NO_x was missing from the file at KDAQ's offices. Pursuant to Section 505(b)(2) of the CAA, 42 U.S.C. § 7661d(b)(2), a "petition shall be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided by the permitting agency." Thus, not only must issues be raised during the public comment period, but they must be raised sufficiently to meet the threshold requirements. The Act does provide for an exception to this threshold requirement if the petitioner "demonstrates in the petition to the Administrator that it was impracticable to raise such objections...or the grounds for such objection arose after such period." *Id.* Neither Petition raises these exceptions.[12] As claims regarding the files being disorganized, and unavailability of copies were not raised during the public comment period, consistent with Section 505(b)(2) of the CAA, such issues may not now be raised in a title V petition. Therefore, these issues are denied for procedural reasons. Nonetheless, in order to promote transparency in government decision-making, below is brief discussion on the issues raised by Petitioners.

Public participation requirements found at 40 CFR § 51.166(q) address only the minimum requirements for what must be included in the permit file. Additional requirements are found in Kentucky's SIP-approved rule (401 KAR 52:100) and specify that certain documents be available for public review. *See, e.g.*, 401 KAR 52:100 § 8(1)(a)(specifying that the permit application, draft permit, and supporting materials be made available to the public); *see also* 40 CFR § 70.7(h)(2) (describing the types of information that must be made available to the public for title V permit review). The permit record indicates that the permit file was available for public review at the required locations. KDAQ SOB Revision 2 12-13. According to the SOB, the documents were also available via the KDAQ Web site which provides instant access for many permitting documents. *Id.*

In addition, Petitioners have not demonstrated that their public participation claims regarding file organization and copies prevented a meaningful assessment of the issues, or a flaw in the permit. *See, e.g., Valero Refining Company*, at 44; *In the matter of Pencor-Masada Oxynol, LLC*, Petition No. II-2000-07 (Order on Petition) (May 2, 2001) at 5-8 (describing

[12] With regard to Petitioners' claim that certain requested documents were not received until after the close of the comment period, we note that they did not raise this concern to Kentucky in the comments they submitted on the Permit, nor did they raise this concern in the requests for an extension of the comment period that they filed with the Kentucky. Petitioners did have access to the file for viewing at the KDAQ office, so the information itself was available to Petitioners. Finally, we note that in neither petition requesting EPA to object to the permit do they attempt to identify concerns with specific information they received after the close of the comment period.

standards for reviewing public participation concerns). Further, as was discussed above, Petitioners did have the benefit of a second public comment period (on Revision 3).

Even though EPA is denying this claim in the Petition because Petitioners have not demonstrated that KDAQ failed to comply with an applicable public participation requirement, EPA has concerns regarding KDAQ's treatment of the Petitioners in their efforts to view the permit file and obtain copies of the file. Consistent with Section 502(b)(8), 42 U.S.C. § 7661a(b)(8), state rules shall provide "reasonable procedures consistent with the need for expeditious action by the permitting authority on permit applications and related matters, to make available to the public" certain permitting information. As a result, EPA strongly urges that KDAQ review its procedures regarding public inspection of its permit files and ensure that such procedures allow for inspection of the entire permit file at the beginning of the public comment period, and that the file is well-organized. Further, if no copier is provided for use by the public, EPA strongly recommends that KDAQ provide the public with a procedure by which copies may be obtained in a timely manner. Such steps will further open and transparent government, which ultimately helps to support government decisions and actions. In the RTC for Revision 2, KDAQ committed to "take under advisement suggestions to improve its public out reach procedures." KDAQ RTC Revision 2 at 13. EPA supports open and transparent government decision-making and is available to further advise KDAQ about improvements in its procedures for ensuring an adequate public participation for PSD and title V permits.

2. *KDAQ failed to extend the public comment period*

Petitioners' Claims. Petitioners state that KDAQ's failure to extend the comment period was unreasonable because of "gross inadequacies" in the public review process. Petition 1 at 12. Specifically, Petitioners allege that the extension was warranted due to the delays associated with identifying the location of the permit file (*see* Petitioners' Exhibit F (Declaration of Joan S. Lindop, Sierra Club member)), as well as delays associated with obtaining a copy of the permit file. Petition 1 at 12-13. Petitioners cite to a situation in Illinois, which they claim is similar and for which an extension was granted.

EPA's Response. As an initial matter, we believe that this issue is now moot due to the subsequent public comment period on Revision 3. Because Kentucky did not limit the scope of comments that could be submitted on Revision 3, the Petitioners had a second opportunity to submit comments on any issues for which they believed they had an insufficient opportunity to do so on Revision 2. We note that Petitioners took advantage of this opportunity and submitted numerous comments that went beyond the limited scope of the revisions that were the focus of Revision 3 – including raising issues that could have been raised during the Revision 2 process. Thus, to the extent a new or extended comment period may have been warranted, it has already been provided.

Nonetheless, Petitioners have not demonstrated that Kentucky acted inconsistent with applicable requirements or requirements under title V in denying Petitioners' request for an extension of the comment period on Revision 2. Kentucky's regulations at 401 KAR 52:100 do not explicitly require that extensions to public comment periods be granted. Extensions are also not explicitly discussed by applicable federal rules. 40 CFR § 70.7(h)(2), 40 CFR § 51.166(q).

As a general matter, permitting authorities have discretion to extend (or not) a public comment period.

Petitioners describe Ms. Lindop's unfortunate experience in attempting to view and obtain a copy of the LG&E permit file. However, in requesting the extension of time from KDAQ prior to the close of the comment period, Petitioners did not raise any of the concerns raised in the Petition. *See* Petitioners Exhibit G (E-mail from John Blair, Valley Watch, Inc. to John Lyons). Instead, Petitioners stated that an extension was necessary because "so many new sources" were being proposed in Kentucky. *Id.* Petitioners' comment letter also included a request for an extension of time (Petitioners' Exhibit A at 3), but providing little detail in terms of why an extension (or re-opening of the comment period) was warranted. Petitioners have not demonstrated that KDAQ's exercise of its discretion, based on the facts that were presented to it in this circumstance, was arbitrary, capricious or resulted in a flaw in the permit. *See, e.g.*, *Valero Refining Company* at 44. In addition, the matter is now moot. Therefore, the Petitions are denied as to this issue.

B. Petitioners' PSD Related Issues

Background on PSD and BACT Applicable to All PSD/BACT Related Issues Raised in Petition

The CAA and corresponding PSD regulations require that new major stationary sources and major modifications of such sources employ BACT to minimize emissions of regulated pollutants emitted from the facility in significant amounts. CAA § 165(a)(4), 42 U.S.C. § 7475(a)(4); 40 CFR § 52.21(j)(2); 401 KAR 51:017 § 8(2), (3). BACT is defined to mean,

> an emission limitation based on the maximum degree of reduction [of pollutants emitted from the facility] which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.

CAA § 169(3), 42 U.S.C. § 7479(3).

EPA has developed a "top-down" process that permitting authorities use to ensure that a BACT analysis satisfies the applicable legal criteria. The top-down BACT analysis consists of a five-step process which provides that all available control technologies be ranked in descending order of control effectiveness, beginning with the most stringent. *See Prairie State,* slip. op. at 17-18. The most stringent control technology is deemed the control necessary to achieve BACT-level emission limits unless the applicant demonstrates, and the permitting authority determines, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not achievable in that case. An incomplete BACT analysis, including failure to consider all potentially applicable control alternatives, constitutes clear error. *See, e.g., Prairie State,* slip op. at 19; *In re Knauf Fiber Glass, GmbH,* 8 E.A.D. 121, 142 (EAB, February 4, 1999); *In re Masonite Corp.* 5 E.A.D. 551, 568-569 (EAB, November 1, 1994). The five steps in the top-down process are summarized below:

a. Identify all available control technologies;
b. Eliminate technically infeasible options;
c. Rank remaining control technologies by control effectiveness;
d. Evaluate the economic, environmental, and energy impacts of the options; and
e. Select BACT.

Prairie State, slip op. at 17-18. Although EPA regulations do not require application of this top-down process to meet the BACT requirement, this top-down analysis is frequently used by permitting authorities to ensure that a defensible BACT determination, including consideration of all requisite statutory and regulatory criteria, is reached. LG&E followed this top-down BACT methodology when it submitted its application for modifications at the Trimble County facility, which KDAQ applied in issuing its permitting decision. KDAQ SOB Revision 2 at 15.

1. Petitioner's Claim that the Permit Fails to Include BACT for Carbon Dioxide
(Section III of Petition 2)

Petitioners' Claims. Petitioners claim that EPA must object to the permit because the permit fails to include requirements addressing emissions of carbon dioxide (CO_2) and other harmful greenhouse gases (GHGs) from Unit 31, specifically a BACT analysis for CO_2. Petition 2 at 5-16. In this portion of the Petition, Petitioners raise the following main concerns: (1) Unit 31 will emit millions of tons of CO_2 and other GHGs; (2) CO_2 is an air pollutant under Kentucky and federal law; (3) CO_2 is subject to regulation under the CAA (Sections 202, 821 and 40 CFR Part 75) and Kentucky law (401 KAR 52:060); (4) the permit cannot issue without the required emissions information for CO_2; and (5) the permit cannot issue without BACT limits for CO_2 (also stating, among other points, that the PSD significance level for CO_2 is "any emissions," and that a BACT analysis should consider carbon capture and sequestration).

EPA's Response. In its response to comment on this issue, KDAQ identified the provision of the Kentucky SIP that requires it to implement the state PSD program in a manner that is no more stringent than the federal PSD program. KDAQ RTC Revision 3 at 13 (citing Kentucky Revised Statutes (KRS) 224.10-100(26)). KDAQ then found that there were no federal PSD requirements to control CO_2 at stationary sources,[13] and KDAQ explained that the Kentucky PSD regulations did not require a BACT analysis for CO_2 emissions in Revision 3. *Id.* Implicit in KDAQ's conclusion that the permit would not include a CO_2 BACT limit was an

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[13] As Petitioners note, KDAQ did incorrectly state that there "there are no federal regulations establishing requirements for CO_2 at stationary sources." KDAQ RTC Revision 3 at 13. However, given that this sentence directly follows KDAQ's discussion of the SIP requirement to implement their PSD program no more stringently than the federal PSD program and directly precedes their discussion of state BACT requirements, we think this sentence is more appropriately interpreted to say that Kentucky found there are no federal regulations establishing PSD requirements for CO_2 at stationary sources.

understanding that the federal PSD program did not apply to CO_2 emissions at the time Revision 3 was issued. As discussed below, Petitioners have failed to demonstrate that KDAQ's reliance on the SIP and its assumptions regarding the federal PSD program requirements led to a permit that is deficient under the CAA.[14]

When KDAQ issued permit Revision 3 in January 2008, at least one EPA Region and the EPA program office that oversees implementation of the federal PSD permitting program had taken the position that CO_2 emissions were not subject to federal PSD requirements because they believed there was a binding, historic interpretation of the phrase "subject to regulation" in the federal PSD regulations that required PSD regulations to applied only to those pollutants already subject to actual control of emissions under other provisions of the CAA.[15] *See* EPA Region 7's Response to Petition for Review, *In re: Deseret Power Electric Cooperative*, PSD Appeal No. 07-03 (filed November 2, 2007); Brief of the EPA Office of Air and Radiation, *In re: Christian County Generation, LLC*, PSD Appeal No. 07-01 (filed September 24, 2007). Accordingly, these EPA offices argued that the regulations in the CAA Acid Rain program that require monitoring of CO_2 at some sources (and which are cited by Petitioners in this matter) did not make CO_2 subject to PSD regulation. *Id.* Thus, it was not implausible for KDAQ to assume that the federal PSD program did not require permits to include limits for CO_2 emission because, at the time KDAQ issued Revision 3, two EPA offices that implement and interpret the requirements of the federal PSD program had taken that position. Moreover, at that time, no federal permitting authorities had actually imposed PSD requirements for CO_2; in fact, no federal PSD permit has since issued which included CO_2 limits.

A decision of EPA's Environmental Appeals Board ("EAB") subsequently addressed the position that CO_2 emissions were not subject to PSD regulation. *See In re: Deseret Power Electric Cooperative*, 14 E.A.D. ___, PSD Appeal No. 07-03 (EAB, November 13, 2008). The EAB determined that prior EPA actions were insufficient to establish a historic, binding interpretation that "subject to regulation" for PSD purposes included only those pollutants subject to regulations that require actual control of emissions. However, the EAB did not conclude that such an interpretation was impermissible under the CAA and found "no evidence of a Congressional intent to compel EPA to apply BACT to pollutants that are subject only to monitoring and reporting requirements." *Id.* at 63. Shortly thereafter, in order to address the ambiguity that existed in the federal PSD regulations following the EAB decision, then Administrator Stephen Johnson issued a memorandum setting forth the official EPA interpretation regarding which pollutants were "subject to regulation" for the purposes of the

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[14] Petitioners also included a request for EPA to reopen the LG&E permit to include PSD BACT limits for CO_2 emissions. Petition 2 at 10. In light of the circumstances discussed below, EPA also declines at this time to undertake a discretionary reopening of the LG&E permit to include such limits.

[15] Under the federal PSD permitting regulations, only newly constructed or modified major sources that emit one or more "regulated NSR pollutants" are subject to the requirements of the PSD program, including the requirement to install BACT for those regulated NSR pollutants that the facility emits in significant amounts. "Regulated NSR pollutants" include "any pollutant that otherwise is subject to regulation under the Act." 40 CFR § 52.21(b)(50)(vi); *see also* 401 KAR 51:001 § 1(210).

federal PSD permitting program. Memorandum from Stephen Johnson, EPA Administrator, to EPA Regional Administrators entitled, "*EPA's Interpretation of Regulations that Determine Pollutants Covered by Federal Prevention of Significant Deterioration (PSD) Permit Program*" (December 18, 2008) (Johnson Memo); *see also* 73 *Fed. Reg.* 80,300 (December 31, 2008) (public notice of December 18, 2008 memo). The Johnson Memo established an interpretation of "subject to regulation" within the federal PSD regulations that "exclude[d] pollutants for which EPA regulations only require monitoring or reporting but [] include[d] each pollutant subject to either a provision in the Clean Air Act or regulation adopted by EPA under the Clean Air Act that requires actual control of emissions of that pollutant." Johnson Memo at 1; 73 *Fed. Reg.* at 80,301. EPA received a petition for reconsideration of the position taken in the Johnson Memo, and on February 17, 2009, the new Administrator granted that petition. Letter from Lisa P. Jackson, EPA Administrator, to David Bookbinder, Chief Climate Counsel at Sierra Club (February 17, 2009). In granting reconsideration, Administrator Jackson announced the intent to conduct a rulemaking to take public comment on the issues raised in the memo, but she did not stay the effectiveness of the Johnson memo pending reconsideration.[16]

While KDAQ's implicit assumption at the time Revision 3 was issued – that there was an established federal standard that did not require PSD permits to include limits for CO_2 emissions – was later overturned by the EAB, it does not mean that Petitioners have demonstrated that KDAQ's reliance on this assumption led to a permit that is deficient under the CAA. Petitioners assert that Revision 3 was issued in error because CO_2 "is clearly 'subject to regulation' under the [CAA] and Kentucky law," based on CAA regulations requiring their monitoring and reporting. Petition 2 at 7. Petitioners are essentially arguing that at the time KDAQ issued the permit, the federal PSD program required application of BACT requirements to CO_2 emissions and KDAQ erred by not including such limits. However, this argument fails because the EAB specifically found that there was no established standard regarding whether CO_2 was "subject to regulation" under the federal PSD program and that the position urged by Petitioners – PSD regulation of CO_2 was required given existing monitoring and reporting requirements – is not clearly dictated by the language of the CAA or EPA regulations. *Deseret Power* at 63. Accordingly, Petitioners have not established that KDAQ's failure to require CO_2 emissions limits in this permit was incorrect because they did not show that KDAQ implemented the Kentucky PSD program in a manner less stringent than the existing federal PSD program.[17] Because Petitioners have not demonstrated that Revision 3 is inconsistent with the requirements of the Act, the Petition 2 is denied with respect to this issue.[18]

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[16] The grant of reconsideration also re-iterated that states must issue PSD permits "under their own State Implementation Plans." February 17, 2009 letter granting reconsideration at 1; *see also* Johnson Memo at 3, n. 1 ("To the extent approved State Implementation Plans contain the same language as used in [the relevant federal PSD regulations], States *may* interpret that language in state regulations in the same manner reflected in this memorandum.") (emphasis added).

[17] The position taken in KDAQ's permitting decision rests on the interplay of its SIP and the federal PSD program, and that decision is consistent with the EPA's present position regarding which pollutants are subject to federal PSD permitting requirements.

[18] Actions are underway at EPA that could, when finalized, result in the promulgation of final standards controlling the emission of greenhouse gases. In particular, EPA has announced its

2. ***Petitioners' Claims that the Permit fails to include air quality monitoring demonstration during periods of startup, shutdown, and maintenance***
(Sections IX and X of Petition 2)

Petitioners' Claims. In Section IX of Petition 2, Petitioners reiterate the issues raised in Section II. E. of Petition 1 that the permit fails to include BACT for periods of startup, shutdown and malfunction. Petition 1 at 24. These issues were already responded to in EPA's September 10, 2008, Partial Order. In Section X, Petitioners comment that KDAQ's failure to consider BACT for periods of startup, shutdown and malfunction also resulted in a failure to demonstrate that Unit 31 "will not cause or contribute to a violation of NAAQS or PSD increment." Petition 2 at 51. Petitioners cite to CO, VOCs and NO_x as pollutants of concern although Petitioners' focus is on VOCs because the VOC potential to emit was estimated at 97.8 tpy, a level that allowed LG&E not to evaluate air quality impacts for ozone. Petitioners suggest that VOC emissions can be higher during periods of startup, shutdown and malfunction, and that such emissions "can be significant in terms of triggering an ambient air quality analysis to assess compliance with ozone NAAQS and increments." Petition 2 at 52.

EPA's Response. Pursuant Section 165 of the CAA, the PSD preconstruction requirements include, among others, an air quality analysis and PSD increment analysis. 42 U.S.C. § 7475. EPA promulgated rules providing details on the air quality and PSD increment analyses, and Kentucky also adopted rules consistent with the CAA and EPA's regulations, which are incorporated into Kentucky's SIP. 401 KAR 51:017 §§ 9-14; *see also* 40 CFR §§ 52.21(c)-(p), (r). Kentucky's rules at 401 KAR 51:017 § 11 describe a PSD permit applicant's obligation to provide to KDAQ an "analysis of ambient air quality in the area that the major stationary source or major modification will affect." *Id.* at (1)(a). The analysis is specific to regulated pollutants for which the major modification will result in a significant net increase – and how those increases might affect the area's ability to maintain the current NAAQS attainment status. 401 KAR § 51:017; *see also* KDAQ SOB Revision 2 at 31. Ozone is treated differently from other pollutants for which there is an established NAAQS because ozone is not emitted directly from sources. As a result, an ozone air quality analysis cannot be performed on a source-by-source basis in the same manner as an analysis for PM or the other NAAQS pollutants. Therefore, air quality impact analyses for ozone focus on ozone precursors, primarily VOCs and NO_x. NO_x is a precursor for ozone although KDAQ's SIP-approved rules have not yet been updated to include NO_x as an ozone precursor.

In the Revision 2 SOB, KDAQ explained that LG&E provided the information required by Kentucky rules for the ambient air quality analysis. KDAQ SOB Revision 2 at 31-32. Pursuant to Kentucky rules (which are consistent with federal rules), KDAQ may exempt a project from an ambient air impact analysis if the project would result in a net emissions increase of less than the amounts listed in the table in 401 KAR 51:017 § 7(5)(a). Petitioners raise specific concerns regarding VOCs and ozone. For ozone, 401 KAR 51:017 § 7(5)(a) explains

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intention to propose a rule regulating greenhouse gas emissions from light-duty vehicles; that rule would control the emission of greenhouse gases within the meaning of the Johnson Memo.

that, "No de minimis air quality level is provided for ozone. However, a net increase of 100 tpy or more of VOCs subject to this administrative regulation is required to perform an ambient impact analysis including the gathering of ambient air quality data." *Id.* LG&E's 2004 Application explains the origin of LG&E's determination that the net emissions increase for VOCs would be 97.5 tpy (thus allowing KDAQ to exclude the source from ozone related air quality analyses). 2004 Application at 2-11-2-15. Specifically, LG&E evaluated emissions from 9 emissions sources associated with the Unit 31 modification. *Id.* at 2-11. The emissions from these sources were based on projected fuel burn rates, engineering design estimates, and EPA AP-42 emissions factors.[19] *Id.* In addition, LG&E explained that "combustion calculations were performed to develop representative stack parameters and emission rates..." *Id.* For Unit 31, LG&E explained that "emissions and stack parameters were developed for unit loads of 100, 75, and 50 percent of maximum capacity over a range of representative ambient temperatures...as well as for three potential coal fuels." *Id.* These analyses were then used to determine the potential-to-emit resulting from the modifications, and then compared with previous emissions to determine the net emissions increase pursuant to Kentucky's SIP-approved rules at 401 KAR 51:017.[20]

The result of these analyses was a projected net emissions increase of 97.8 tpy for VOCs. KDAQ SOB Revision 2 at 3-6. In the Revision 3 analysis, this number was revised to 97.5 tpy for VOCs, but the substance of the analysis remained unchanged. KDAQ SOB Revision 3 at 3. Because the projected net emissions increase was below 100 tpy, Kentucky concluded that LG&E was not required to conduct an ambient air analysis for ozone. 401 KAR 51:017 § 7(5)(a); see also 2004 Application at 4-35 (requesting the §7(5)(a) exemption).

Petitioners do not identify any specific flaws in the analysis performed by LG&E or KDAQ with regard to CO, VOCs, or NO_x. Rather, Petitioners seem to rely on a presumption that emissions during startup and shutdown periods can be higher than during other operating periods. Petition 2 at 52. With regard to CO and NO_x, Petitioners provide no specific information demonstrating any flaw in the analyses performed by LG&E and KDAQ. Slightly

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[19] An emissions factor is a representative value that attempts to relate the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant. These factors are usually expressed as the weight of pollutant divided by a unit weight, volume, distance, or duration of the activity emitting the pollutant (e.g., kilograms of particulate emitted per megagram of coal burned). Such factors facilitate estimation of emissions from various sources of air pollution. In most cases, these factors are simply averages of all available data of acceptable quality, and are generally assumed to be representative of long-term averages for all facilities in the source category. For more information on AP-42 and emissions factors, see http://www.epa.gov/ttn/chief/ap42/index.html.

[20] In determining the actual emissions for evaluating an increase associated with a modification, the rules require that sources consider emissions that are "representative of normal source operations." 401 KAR 51:001 § 1(2)(a). Neither federal law nor Kentucky rules require that sources consider a malfunction as representative of normal source operations. In addition, the nature of malfunctions is such that they are not anticipated events. Petitioners fail to demonstrate that malfunction emissions from this unit will result in an increase of VOC emissions such that the 100 tpy threshold will be met.

more detail is provided for VOCs. With regard to VOCs, Petitioners suggest that because 97.5 tpy is close to the 100 tpy threshold, and because "any increase in VOCs – such as those from startup, shutdown and maintenance – can be significant," that LG&E should have conducted an air quality impact analysis for ozone. Petition 2 at 52.[21] Petitioners provide no information demonstrating that emissions from startup, shutdown can be "significant," or result in an increase that would push LG&E over the 100 tpy threshold. Further, Petitioners fail to identify any specific portion of LG&E's analyses described in its 2004 or 2007 Applications where LG&E's analysis is not consistent with applicable law. As explained by LG&E, the emissions analyses were based on several scenarios, including unit loads of 100% (which are significantly greater than unit loads that would exist during a period of shutdown or startup). 2004 Application at 2-11. These emissions increases were then compared with previous emissions, consistent with the SIP-approved Kentucky rules, to determine whether such increases were "significant."

The Petitioners rely primarily on the assumption that emissions will increase during periods of startup and shutdown, as opposed to specific flaws in the analyses performed by LG&E and KDAQ. *See, e.g.*, KDAQ SOB Revision 2 at 3-5; 2004 Application at 2-11-2-15 and Appendix E; LG&E February 13, 2007, Application (Revision 3) at Appendix D (Emission Calculations); and Kentucky Cabinet Hearing Officer's Report and Recommended Secretary's Order (Hearing Officer's Report), File No. DAQ-27602-042 (June 13, 2007) at 163-164 (*aff'd* by Secretary on September 28, 2007). While it is generally true that not all control technology will be fully operational during periods of startup and shutdown (such as SCR which requires a certain temperature for the catalyst to function), this does not necessarily correlate to increased emissions during periods of startup and shutdown. As noted above, typically the units are not operating at full loads during such periods either. Petitioners cite to no evidence supporting their allegation on this point that emissions would be greater during these periods than they would be during operation at full-load. VOC emissions at LG&E are related to combustion generally – hence the focus of the analysis on combustion calculations and unit loads. 2004 Application at 2-11-2-15. As noted in the Hearing Officer's Report, Unit 31 would not be expected to be operating at "full load/full capacity" during periods of startup and shutdown; thus, the emissions are expected to be significantly less than those measured by LG&E which assumed maximum capacity loads 365 days a year. KDAQ RTC Revision 2 at 25; *see also* Hearing Officer's Report at 163-164; 2004 Application at 2-11-2-15. In addition, facilities such as LG&E will typically try to minimize emissions during startup by using alternative fuels during startup (such as natural gas). KDAQ RTC Revision 2 at 25; Hearing Officer's Report at 163-164.

Petitioners do not identify any specific step in the analytical process where LG&E's evaluation was not consistent with applicable law. There is no information in the record indicating that the VOC emissions are expected to exceed 100 tpy. Thus, for the reasons described above, Petitioners have not demonstrated that KDAQ's evaluation was unreasonable or resulted in a flaw in the permit. As a result, the Petitions are denied on these issues.

3. ***Petitioners' Claims Regarding BACT for NO_x and SO_2***
(Section II. B. Petition 1; Section V.b Petition 2)

[21] Petitioners also make a vague reference to a failure to evaluate "PSD increment;" however, there is no PSD increment for ozone.

Background on PSD Program and Netting

The PSD program applies to NAAQS pollutants and precursors for which an area has been designated attainment or unclassifiable, *see* CAA §§ 160-169, 42 U.S.C. § 7470-7479, as well as any other "regulated NSR pollutant" as defined in 40 CFR § 52.21(b)(50). The PSD program describes a set of preconstruction requirements applicable to new major emitting facilities (also called major stationary sources), and those undergoing a major modification that triggers PSD review. *See* 42 U.S.C. § 7475. Pursuant to federal rules, a major modification means "any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase...of a regulated NSR pollutant...and a significant net emissions increase of that pollutant from the major stationary source." 40 CFR § 51.166(b)(2)(i); *see also* Kentucky's SIP-approved rules at 401 KAR 51:017 § 1(116). The term "significant" is defined in 40 CFR § 51.166(b)(23) and includes specific emission rates for certain pollutants. *See also*, 401 KAR 51:017 § 1(221). With regard to pollutants for which the CAA does not set a specific emission rate, "significant" is defined as "any net emissions increase" associated with a major modification for those pollutants. 40 CFR 51.166(b)(23).[22]

Netting is a term that refers to the process of considering certain previous and prospective emissions changes at an existing major source to determine if a "net emissions increase" of a pollutant will result from a proposed physical change or change in method of operation. *See* 40 CFR § 51.166(b)(3)(i) (definition of "net emissions increase"), 401 KAR 51:017 § 1(146). The PSD definition of a net emissions increase found in 40 CFR § 51.166(b)(3)(i) (and 401 KAR 51:017 § 1(146)(a)) consists of two components: (a) any increases in actual emissions from a particular physical change or change in method of operation at a stationary source; and (b) any other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable. The first component narrowly includes only the emissions increases associated with a particular change at the source. The second component more broadly includes all contemporaneous, source-wide (occurring anywhere at the entire source), creditable emission increases and decreases. *Id.* The netting analysis is reviewed on the basis of changes in annual (tons per year) emissions. *See* 40 CFR § 51.166(b)(23); *see also Environmental Defense v. Duke Energy Corp.*, 127 S. Ct. 1423 (2007) (upholding EPA's interpretation of modification based upon tons per year of emissions).

Pursuant to federal rules and Kentucky's SIP-approved rules, an increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs between the date five years before construction on the particular change commences and the date that the emissions increase from the particular change occurs. 40 CFR § 52.21(b)(3)(ii)(a)-(b), 401 KAR 51:017 § 1(146)(b)(2). Applicable rules also describe when an increase or decrease in actual emissions is "creditable." 40 CFR § 52.21(3)(iii); 401 KAR 51:017 § 1(146)(c)-(f). Generally, to be creditable, a contemporaneous reduction must be

[22] The concept of a "net" emissions increase was challenged following EPA's promulgation of the NSR rules in 1978 (43 *Fed. Reg.* 26,380, June 19, 1978) and upheld by the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit). *See, e g., Alabama Power Co. v. Costle*, 636 F.2d 323 at 402-403 (D.C. Cir. 1979).

enforceable on and after the date construction on the proposed modification begins. The actual reduction must take place before the date that the emissions increase from any of the new or modified emissions units occurs. In addition, the permitting agency must ensure that the source has maintained any contemporaneous decrease which the source claims has occurred in the past. The source must either demonstrate that the decrease was enforceable at the time the source claims it occurred, or it must otherwise demonstrate that the decrease was maintained until the present time and will continue until it becomes enforceable. An emissions decrease cannot occur at, and therefore, cannot be credited from an emissions unit which was never constructed or operated, including units that received a PSD permit. In addition, reductions must be of the same pollutant as the emissions increase from the proposed modification and must be qualitatively equivalent in their effects on public health and welfare to the effects attributable to the proposed increase. *Id.*, *see also* 45 *Fed. Reg.* 52,676, 52,698-52,699 (August 7, 1980) (explaining contemporaneous and creditable in the preamble to the rule promulgating EPA's 1980 NSR rule revisions).

For emissions decreases occurring at the same facility, of the same pollutant, within the applicable contemporaneous time period, KDAQ adopted an approach explained in the RTC Revision 2. KDAQ RTC Revision 2 at 18. Under this approach, there exists a presumption that the emissions decrease will have approximately the same qualitative significance for public health and welfare as that attributed to the related increase, unless the permitting agency has reason to believe that the reduction in ambient concentrations from the emissions decrease will not be sufficient to prevent the proposed emissions increase from causing or contributing to a violation of any NAAQS or PSD increment. The language regarding qualitative significance for public health and welfare stems from the purpose of the Act in Section 101(b)(1), 42 U.S.C. § 7401(b)(1). As in the case of LG&E, in order to ensure that the emissions reductions are contemporaneous and creditable for netting purposes, a regulated entity may seek a voluntary reduction in emissions not associated with any other change at the facility.

In summary, the netting analysis performed by a permitting authority tends to follow a six-step process: (1) determine emission increases from the proposed project; (2) determine the beginning and ending dates of the contemporaneous period as it relates to the proposed modification; (3) determine which emission units at the source have experienced an increase or decrease in emissions during the contemporaneous period; (4) determine which emissions changes are creditable; (5) determine, on a pollutant-by-pollutant basis, the amount of each contemporaneous and creditable emissions increase and decrease; and (6) sum all contemporaneous and creditable increases and decreases with the increase from the proposed modification to determine if a significant net emissions increase will occur. 45 *Fed. Reg.* at 52,698; *see also* Memorandum entitled, "*Proposed Netting for Modifications at Cyprus Northshore Mining Corporation, Silver Bay, Minnesota*," from John Calcagni to David Kee (August 11, 1992) at 3-6. At the conclusion of the netting analysis, the permitting authority can then determine the specific pollutants for which there is a significant net increase in emissions, and thus, would be subject to PSD review. *See, e.g., In re Hawaii Electric Light Company, Inc.*, 8 E.A.D. 66 (EAB, November 25, 1988) (discussing elements of the netting analysis).

Background on KDAQ Netting Analysis for LG&E

In November and December of 2004, LG&E submitted to KDAQ two minor permit revisions for voluntary creditable decreases in emissions of NO_x and SO_2 from the already existing and permitted Unit 1, in anticipation of future construction of Unit 31. KDAQ SOB Revision 1 Minor Modification (January 20, 2005). KDAQ's review of the voluntary decrease in emissions was completed consistent with Kentucky's PSD rules.[23] As part of its permit application to reduce emissions, LG&E explained its intention to use the emission decreases of NO_x and SO_2 in its netting calculations for the forthcoming modification. KDAQ SOB (Revision 1 – Minor Modification); *see also* KDAQ SOB (Revision 2) at 3, 6. The Revision 2 SOB explained that for NO_x, LG&E would reduce the emissions through a combination of increased removal efficiency and increased SCR operating time. KDAQ SOB Revision 2 at 5, 6. For SO_2, KDAQ explained that the reductions would be achieved through capital investments to increase overall WFGC removal efficiency. *Id.* In Revision 3, KDAQ noted that there were some adjustments to the emissions for NO_x and SO_2, but concluded that LG&E was still able to net-out of PSD for NO_x and SO_2. KDAQ SOB Revision 3 at 3. In the February 13, 2007 Amendment to Air Construction Permit (Revision 3 Application), LG&E explains the emissions changes associated with the modifications as well as presenting the specific emissions calculations. Revision 3 Application at Section 3.0 and Appendices. Generally, the facts of the LG&E netting involve the situation contemplated by EPA in promulgating its regulations in 1980 – that facilities would upgrade older equipment to reduce emissions and that this may result in creditable emissions decreases. 45 *Fed. Reg.* at 52,700.

These netting issues were raised by Petitioners in their state permit appeal, for which a final order was issued on September 28, 2007. Kentucky Cabinet Secretary's Final Order File No. DAQ-27602-042 (September 28, 2007); *see also*, Kentucky Cabinet Hearing Officer's Report at 67-105. As part of Revision 3 to the permit, KDAQ revised the netting analysis, although the ultimate result was that KDAQ still concluded that the modification satisfied the netting requirements and was able to "net-out" of PSD review for NO_x and SO_2. As explained by KDAQ, the additional control equipment required by KDAQ as part of the permit had the effect of reducing the net emissions increase for NO_x and SO_2 by 2.9 tpy and 0.9 tpy, respectively. KDAQ SOB Revision 3 at 4. KDAQ also noted that even with some increases from emission units such as the auxiliary boiler, there were "no changes to the project's applicability under the original PSD review process from what was determined for the 2004 Application." KDAQ SOB Revision 3 at 3.

Petitioners' Claims. Petitioners raised a number of concerns regarding the netting in Petition 1. Petitioners raised some new concerns in Petition 2. All are outlined in this paragraph and discussed below. In Petition 1, Petitioners state that the netting analysis for NO_x and SO_2 was erroneous, and thus, it was incorrect for KDAQ to allow Unit 31 to avoid full PSD review for NO_x and SO_2 (i.e., a full BACT analysis). In Petition 1, Petitioners' issues stem from two

[23] These rules became effective as a matter of State law on July 14, 2004. At the time that these rules were relied upon by KDAQ, they had been submitted to EPA for approval into the SIP. The rules reflected changes made by EPA to the federal NSR rules – the 2002 NSR Reform Rules. EPA subsequently approved these rules into the Kentucky SIP. 71 *Fed. Reg.* 38,990 (July 11, 2006). The delay was associated with litigation on the 2002 NSR Reform Rules that did not impact any issues raised by Petitioners.

basic concerns – that the reductions in NO_x and SO_2 were neither creditable nor contemporaneous. Petition 1 at 14-18. Petitioners claim in Petition 1 that the emission decreases at Unit 1 were not "creditable" for use at Unit 31 because KDAQ did not: (1) properly determine that the decreases had the same qualitative significance for public health and welfare as the increase in emissions at Unit 31; (2) consider that the SCR on Unit 1 was installed as a result of the NO_x SIP Call or other SIP requirements and thus any decreases in emissions cannot be used for netting; and (3) properly consider the timing of the increases per the ozone season. Petitioners claim in Petition 1 that the emission decreases at Unit 1 were not "contemporaneous" because KDAQ: (1) used "baseline emissions" instead of "actual emissions" for the netting calculations; (2) only the two prior consecutive years may be used for determining actual emissions; and (3) the SO_2 reductions at Unit 1 were required by another regulatory program (the CAA title IV program) and thus were not available for netting under the NSR program.

In Petition 2, Petitioners raise two additional concerns. Petition 2 at 28-29. First is the claim that LG&E did not properly document its emissions calculations for NO_x associated with the increase in size and operation of the auxiliary boiler. Second is the claim that LG&E did not properly document its emissions for NO_x associated with the emergency diesel generator. *Id.*

EPA's Response to Petition 1 Netting Issues

a. Concerns regarding whether decreases were creditable

Petitioners allege that the netting analysis fails to apply the requirement that the creditable decreases be of the same qualitative significance for public health and welfare as the increases for both NO_x and SO_2, with an emphasis on the NO_x emissions. Petition 1 at 14-16. For emissions decreases occurring at the same facility, of the same pollutant, within the applicable contemporaneous time period, KDAQ adopted an approach explained in the RTC Revision 2. KDAQ RTC Revision 2 at 18. Under this approach, there exists a presumption that the emissions decrease will have approximately the same qualitative significance for public health and welfare as that attributed to the related increase, unless the permitting agency has reason to believe that the reduction in ambient concentrations from the emissions decrease will not be sufficient to prevent the proposed emissions increase from causing or contributing to a violation of any NAAQS or PSD increment. Neither the federal rules, nor Kentucky's SIP-approved rules, articulate that the evaluation of qualitative significance be akin to a formal 'determination' process as Petitioners appear to suggest. Rather, the permitting agency will typically evaluate the emissions decreases and increases per the elements enumerated above, and so long as those elements are met, the netting analysis is sufficient. The 2004 Application describes the creditable emissions reductions (at 2-14 - 2-15), as does KDAQ's SOB for Revision 2 at 3-6. *See also* KDAQ RTC Revision 2 at 18. Therefore, the requisite analysis for determining credibility was completed by KDAQ.

As noted by Petitioners, during the public comment period, EPA submitted a comment to KDAQ on the issue of qualitative significance. EPA's comment to KDAQ underscores the key issue associated with the qualitative significance analysis. Notably, EPA commented that the qualitative significance analysis needs to "take into account the dispersion characteristics of Unit 1 in comparison with the dispersion characteristics of the proposed new NO_x and SO_2 emissions units." Petition 1 at 15 (quoting EPA comments on draft permit). In this sense, the qualitative analysis may be a simple one. For example, one issue associated with evaluating the qualitative relationship of emissions may be comparing stack heights of different units. If, for example, decreases in emissions are taken through a stack that is 500 feet tall and the increases are emitted by a stack that is only 15 feet tall, these emissions may not have the same qualitative significance because the emissions from the lower stack may have a greater impact on ground level pollutants than the emissions from the higher stack. This is not to say that such impact is a certainty, but rather, that it would need to be evaluated as part of the netting analysis. EPA's comment to KDAQ was just a reminder that KDAQ conduct this type of analysis if the dispersion characteristics of the new unit, as compared with the existing unit, significantly differed. EPA typically includes this reminder in draft permit comments that include netting, and EPA's comment is not an indication that KDAQ had not properly undertaken the netting analysis. Petitioners make no allegations regarding any physical characteristic of Unit 1 versus Unit 31 that implicates concerns regarding the qualitative significance of the emissions. They are two similar emission units (Unit 1 is a 500 MW unit and Unit 31 will be a 750 MW unit), located at the same facility, with similar technical features such as emission points, and the decreases/increases occurred within the appropriate time period. KDAQ SOB Revision 2 at 3-7. Thus, Petitioners are incorrect in claiming that EPA's comment demonstrates a flaw in KDAQ's qualitative significance analysis.

Petitioners also allege that KDAQ "failed to examine all of the reasons for Trimble reducing NO_x emissions and assessing whether those reasons preclude use of the reductions in a netting calculation." Petition 1 at 16. Petitioners cite to possible use of the same reductions to satisfy the NO_x SIP Call[24] or other ozone SIP obligations. Petition 1 at 15-16. The minor modification sought by LG&E for netting purposes was to achieve greater NOx reductions than already required. 2004 Application at 2-16 (explaining that creditable NOx reductions from Unit 1 were achieved through a combination of increased removal efficiency and/or increased SCR operating time); see also, KDAQ SOB Revision 1 (Minor Modification) at 1; KDAQ RTC Revision 2 at 17. The creditable emissions decreases for NO_x resulted from LG&E voluntarily reducing the annual limit for NO_x to 0.45 lbs/mmBTU from 0.7 lbs/mmBTU. *Id.* Petitioners state that as a result of the NO_x SIP Call, the facility generated reductions of NO_x emissions (Petition 1 at 15); however, Petitioners do not explain how those reductions relate to or implicate reductions obtained by LG&E for netting purposes. The Permit Revision 3 includes a section on

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[24] On October 27, 1998, EPA finalized the "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone"— commonly called the "NO_x SIP Call." 63 *Fed. Reg.* 57,356. The NO_x SIP Call was designed to mitigate significant transport of NO_x, one of the precursors of ozone. For those states opting to meet the obligations of the NO_x SIP Call through a cap-and-trade program, EPA included a model NO_x Budget Trading Program rule in 40 CFR Part 96. Kentucky is included in the NO_x SIP Call and implements the program through 401 KAR 51:001, 51:160 (for utilities), 51:180, 51:190, and 51:195. EPA approved Kentucky's NO_x SIP Call rules into the SIP on April 11, 2002. 67 *Fed. Reg.* 17,624.

the NO_x SIP Call (Section K).[25] KDAQ responded to Petitioners' comments on the NO_x SIP Call, explaining why Petitioners were not correct about the emissions used for the LG&E netting analysis. KDAQ RTC Revision 2 at 17. In Petition 1, Petitioners do not address specific concerns with KDAQ's RTC, or explain why it was not correct. KDAQ's evaluation on this issue is consistent with applicable requirements and Petitioners have not demonstrated that the netting analysis was flawed.

In addition, Petitioners suggest that the NO_x reductions associated with LG&E's minor modification were also used as part of Kentucky's plan to achieve compliance with the NAAQS. Petition 1 at 15. Petitioners do not identify any specific attainment demonstration or maintenance plan that included source-specific requirements for LG&E's Trimble County facility. As described in 40 CFR Part 81, Trimble County is designated as attainment for all the NAAQS. Although other areas in Kentucky are designated as nonattainment, there is no information indicating that emission reduction requirements for LG&E's Trimble County facility are relied upon as part of a SIP for the areas designated as nonattainment in Kentucky. There is nothing in the record that indicates that the reductions that LG&E requested from KDAQ were for any other purpose but netting. KDAQ SOB (Revision 2) at 3-6; KDAQ RTC at 5, 14-15, and 17-18. One result of the numerous applicable requirements for NO_x and SO_2, among other pollutants, is that facilities seeking creditable and contemporaneous emission decreases for netting will have to achieve emission reductions that have *some* relationship to other reductions required by law. Applicable requirements do not prohibit netting simply because the emissions reductions bear some relationship to a reduction requirement. *See, e.g.*, 40 CFR § 52.21 (b)(3)(iii); 401 KAR 51:100 § 1(146)(f). Thus, Petitioners have failed to demonstrate that KDAQ's analysis for LG&E's netting failed to meet any applicable requirement either federal regulations or Kentucky's SIP-approved rules.

Lastly, Petitioners appear to suggest that the "same qualitative significance for public health and welfare" means that the "increases from the project should be offset by decreases that occur in the same amount and at the same time." Petition 1 at 15. Petitioners seem to suggest that the creditable decreases will actually result in an increase of NO_x emissions during the ozone season. Petition 1 at 16. In responding to Petitioners' comments on this point, KDAQ explained its position on qualitative significance and applied the LG&E facts to that stated framework. KDAQ RTC Revision 2 at 18. Petitioners fail to explain why the interpretation adopted by KDAQ was inappropriate. Thus, Petitioners failed to demonstrate that KDAQ's analysis was flawed.

Additionally, the applicable requirements do not require that the exact amount of emissions increased must be decreased to qualify for netting (i.e., net zero emissions). Rather, so long as the "net emissions increase" is below the *significance threshold* for listed pollutants (which includes NO_x and SO_2), then the major modification is not subject to PSD review for those pollutants. 40 CFR § 51.166(b)(23)(i) (definition of "significant"); *see also* 401 KAR

[25] As noted by KDAQ in the RTC, the NOx SIP Call program includes a trading component. As a result, the mere existence of the NOx SIP Call does not mean that every electric generating facility in a NOx SIP Call state would have to install controls and/or operate the facility to meet certain limits. KDAQ RTC Revision 2 at 17.

51:100 § 1(221). Therefore, there is no requirement that a facility have a net zero increase of emissions due to creditable decreases. Netting is established by evaluating emissions on a tons per year basis – not simply evaluating emissions during a portion of the year (e.g., ozone season versus non-ozone season). *See, e.g.*, 40 CFR § 52.21(b)(23)(i) (noting significant rates in tpy); 401 KAR 51:001 § 1(221). In order to effectuate the voluntary, creditable decrease in NO_x emissions, Permit Revision 3 establishes several different NO_x emission limits for Unit 1 including a 0.7 lb/mmBTU (3-hour rolling average); 5,559 tpy (12-month rolling total); and 0.45 lb/mmBTU (annual basis). Permit Revision 3 at 3 (Section B.2 (d)-(f)). These limits ensure that on both a short-term (3-hour average) and a long-term (12-month average) basis, NO_x emissions stay below a specific limit. These limits apply at all times – i.e., both during the ozone season as well as outside of the ozone season.

While Petitioners appear to disagree with KDAQ's analysis with regard to netting, Petitioners fail to provide any information demonstrating that KDAQ failed to adhere to the federal or Kentucky rules regarding the netting analysis, or that the permit fails to include an applicable requirement with regard to netting. Therefore, the Petitions are denied as to these issues.

b. Concerns regarding contemporaneous nature of emissions

With regard to the requirement that emissions increases and decreases be "contemporaneous," Petitioners raise three main concerns. First, that KDAQ used baseline emissions instead of actual emissions. Second, that the SO_2 reductions were required by title IV of the CAA (the acid rain program). And third, that only the two years immediately prior may be used for netting purposes. Petition 1 at 17. In this discussion, Petitioners define "actual emissions" as "those that occur either immediately prior or in the two years prior to" a new limit. Petition 1 at 17.

Petitioners appear to raise two arguments regarding the applicable emissions calculations for determining contemporaneous emissions – one regards the Kentucky rules that are currently SIP-approved, and one regards the Kentucky rule that were SIP-approved at the time of the permitting action. Consistent with federal rules and Kentucky's current SIP-approved rules regarding contemporaneous emissions for netting purposes, "baseline actual emissions" are used for calculating increases and decreases to evaluate the contemporaneous nature of the emissions changes. 401 KAR 51:001 §1(2)(d)(1) (excluding the use of "actual emissions" for calculating a significant emissions increase); 40 CFR § 52.21(3)(i)(b); 401 KAR 51:001 §1(146).[26] These rules explain that facilities like LG&E may choose any consecutive 24-month period within the five year look-back period. 401 KAR § 51:001 §1(20)(a); 40 CFR § 52.21(b)(48) (definitions of "baseline actual emissions"). Applicable requirements explain that the "increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if ... [f]or construction that commences on and after January 6, 2002, the change occurs between the date five (5) years before construction on the change commences, and the date that the increase from the change occurs." 401 KAR 51:001 § 1(146)(b); 40 CFR § 52.21(b)(3)(ii). In Kentucky's

[26] Petitioners suggest that "actual emissions" should have been used instead; however, the rules specify that "baseline actual emissions" be utilized for this purpose.

current rules, baseline actual emissions for calculating increases and decreases in emissions for netting purposes are be determined consistent with the definition of "baseline actual emissions." 40 CFR § 52.21(b)(48); 401 KAR 51:001 § 1(20); *see also* 67 *Fed. Reg.* at 80,202/2-3. Consistent with the definition of baseline actual emissions, any consecutive twenty-four month period within the five years preceding a major modification may be used to calculate baseline actual emissions. *Id.* Further, under existing regulations, different twenty-four month periods (for baseline actual emissions) allowed for different NSR regulated pollutants. 40 CFR § 52.21(b)(48)(ii)(d); 401 KAR 51:001 § 1(20)(b)(2); *see also*, Memorandum entitled, "*Request for Clarification on Policy Regarding the 'Net Emissions Increase,'*" from John Calcagni to William B. Hathaway (September 18, 1989) at 3.

KDAQ described its netting analysis in the SOB for Revision 2 (at 4-6). See also, KDAQ RTC Revision 2 at 14-15. In the instant case, in order to complete the netting calculation, one calculation was completed to determine if the emission decreases at Unit 1 were creditable and contemporaneous, and another calculation was completed to determine the emissions increases at Unit 31. *Id.* These two numbers were then added to determine if there was a 'net emissions increase' of the pollutants at issue. For this calculation, LG&E chose January 2001-December 2002 as the consecutive 24-month period for SO_2, and January 2000 to December 2001 as the consecutive 24-month period for NO_x. KDAQ SOB Revision 2 at 5. The emission decreases were permitted in January 2005 (Revision 1 – Minor Modification). LG&E's 2004 Application was submitted in December 2004, and Revision 2 was issued in January 2006. EPA understands that construction commenced sometime between January 2006 and September 2008. Thus, the chosen consecutive twenty-four month periods were within the contemporaneous time period required by Kentucky's rules (i.e., 5 years as explained above).

Petitioners argue that KDAQ's netting analysis was performed pursuant to NSR rules effective in Kentucky at the time of the analysis, but not yet SIP-approved. Petition at 17. Petitioners suggest that had Kentucky followed its SIP-approved rule, the netting analysis would have been different because it would have used "actual emission" as opposed to "baseline actual emissions." Kentucky's 2003 rules define "actual emissions" as "[a]ctual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during the two (2) year period which precedes the particular date <u>and is representative of normal source operation. The cabinet may allow the use of a different time period upon a determination that it is more representative of normal source operation</u>." 401 KAR 51:017(1)(b)(2003). Thus, KDAQ had the authority under the SIP-approved rules (or the state-effective reform rules) to use any two year period so long as it was more representative of normal source operation. Petitioners have not demonstrated that the two years selected by KDAQ were not 'more representative' or that KDAQ's analysis in choosing those two years was flawed.

Petitioners also raise the concern that the SO_2 reductions used for the netting were required by the CAA title IV Acid Rain Program. Petition 1 at 17. To support this claim, Petitioners point to data indicating that SO_2 emissions from Unit 1 "have consistently declined since 1999...to comply with the Acid Rain Program." Petition 1 at 17. Petitioners overlook, however, that LG&E sought a specific *further* reduction in emissions than was previously required by applicable requirements (as articulated in its title V operating permit), in order to utilize the netting option for the anticipated construction of Unit 31. KDAQ SOB Revision 1 (Minor Modification) at 1. LG&E's current title V permit also contains numerous provisions consistent with title IV, found in Section J (Acid Rain) of the permit. Further, consistent with EPA's interpretation of the federal PSD netting rules, reductions obtained through either title IV (Acid Rain) requirements or other programs, like the NOx SIP Call, may also be used for PSD netting. *See, e.g.*, 57 *Fed. Reg.* 55620, 55626 (November 25, 1992) ("Emission reductions at title IV boilers which are part of an approved title IV averaging group are creditable for purposes of banking, bubbling or netting under title I only to the extent that the emissions reductions at any boiler, subgroup of boilers or the entire group of boilers are surplus to their individual and combined title I emission limitations, enforceable, quantifiable and permanent and take place in a single attainment or nonattainment area"); *see also* Letter from Stephen Rothblatt (EPA Region 5) to Timothy J. Method (Indiana Department of Environmental Management) at 2 (March 29, 1994). Thus, Petitioners failed to demonstrate that the netting performed by LG&E was not consistent with applicable requirements.

EPA's Response to Petition 2 Netting Issues[27]

In Petition 2, Petitioners raise two additional concerns regarding netting. Petition 2 at 28-29. First is the claim that LG&E did not properly document its emissions calculations associated with the increase in size and operation of the auxiliary boiler. Second is the claim that LG&E did not properly document its emissions associated with the emergency diesel generator. *Id.*

The 2007 Application explains LG&E's emissions calculations associated with the changes made to the auxiliary boiler and the emergency diesel generator. 2007 Application at Chapter 3.0 and 4-1. Specifically, LG&E explains:

> Some emissions from the auxiliary boiler increased due to the 1,000 hours of additional operation. However, the sulfur dioxide and sulfuric acid mist emissions decreased due to the switch to ultra low sulfur diesel fuel oil in the new auxiliary boiler. The emissions from the emergency [diesel] generator also changed as a result of the proposed change to ultra low sulfur diesel fuel oil along with the proposed change in the number of hours of operation on an annual basis. Since the optimized design suggests that the emergency diesel fire water pump is not required, the emissions from this source will cause a decrease in the overall [potential-to-emit] summary.

2007 Application at 3-1. Additional emissions information is provided in Appendices C and D to the 2007 Application. In reviewing the information provided, KDAQ adopted LG&E's analysis of the emissions impacts of the proposed changes. Petitioners argue that the application and the SOB do not include the specific calculations. Petition 2 at 29. However, when reviewed in conjunction with the 2004 Application and permitting documents (i.e., KDAQ SOB Revision

[27] In Petition 2, Petitioners note, "their continuing concerns with the insufficiency of the original netting demonstrations" and cite to briefs submitted during the permit appeal through the Kentucky administrative process. Petition 2 at 28. EPA considered Petitioners' netting concerns described in the Petitions and a response to those concerns are included in this Order.

2), all the requisite information is provided. The emissions information provided, and the conclusions reached, are reasonable in light of the totality of the changes. Petitioners do not claim that the end result was incorrect, but rather, that the application failed to contain the requisite information. When taken together, the 2004 and 2007 Applications provide all the information required by applicable regulations – and do provide specific emissions information for the changes described in Revision 3. 2007 Application at 3-5; *see also* KDAQ RTC Revision 3 at 14. Thus, Petitioners have failed to demonstrate that the permit is not in compliance with the Act.

For all the reasons discussed above, Petitioners have failed to demonstrate that KDAQ's analysis for LG&E's netting (including determinations regarding the creditable and contemporaneous nature of the emissions) did not meet a requirement under the CAA. Therefore, EPA is denying Petitioners' request to object to the permit for the netting concerns raised in both Petitions.

4. Petitioners' Claims Regarding BACT for the Auxiliary Boiler
(Section II.F. of Petition 1 and Sections V.b.i and ii of Petition 2)

Petitioners' Claims. In Petition 1, Petitioners state that the BACT analysis for the auxiliary boiler should have included consideration of low-sulfur coal, coal blend, or natural gas. Petition 1 at 26-27. In Petition 2, Petitioners state that a revised BACT analysis was required for the auxiliary boiler, including the consideration of add-on controls. Petition 2 at 34-35. Petitioners have two main concerns. First, Petitioners suggest that KDAQ did not undertake a new BACT determination for the auxiliary boiler, which increased in size and will operate significantly more hours under Revision 3, and instead relied on the Revision 2 determination. Petition 2 at 35. Second, Petitioners argue that a proper BACT determination for the auxiliary boiler must at least consider add-on controls, such as an oxidation catalyst. Petition 2 at 36. Petitioners identify a facility in California (the Crockett Cogeneration Facility) where Petitioner's believe an oxidation catalyst was used. *Id.*

EPA's Response. For the reasons discussed below, EPA is granting the Petition with regard to Petitioners' claims that the BACT analysis for the auxiliary boiler in Revision 3 was not adequate.

In Revision 2, LG&E planned for the facility to maintain the three existing auxiliary boilers, and as part of the construction of Unit 31, to add a new auxiliary boiler. KDAQ SOB Revision 2 at 1. The new auxiliary boiler was included as part of LG&E and KDAQ's BACT analyses for the construction of the new unit. KDAQ SOB Revision 2 at 23; *see also* 2004 Application at Appendix I-54 - I-57. KDAQ concluded that "BACT" for the auxiliary boiler was represented by operational limits on the auxiliary boiler in terms of both fuel content and operating time. *Id.*; Permit Revision 3 at 7. In its response to Petitioners' comments on this issue, KDAQ explained that the construction of the new auxiliary boiler was not subject to a major PSD/BACT analysis for NO_x and SO_2 because of the netting for those pollutants. KDAQ RTC Revision 2 at 25. LG&E also articulated this point in the 2004 Application. 2004 Application at I-54. KDAQ also explained that for this size boiler, there is only a "negligible" difference in emissions for natural gas versus low-sulfur oil for the pollutants subject to BACT – PM, VOC, and CO. KDAQ RTC Revision 2 at 25.

In Revision 3, LG&E determined that the existing three auxiliary boilers were not necessary due to the revised design of the new auxiliary boiler. 2007 Application at 2-1. LG&E explained that the size of the auxiliary boiler would increase, as would the operating times. *Id.* Specifically, the changes to the auxiliary boiler in Revision 3 included increasing the size from 40 million British Thermal Units (mmBTU)/hour to 100 mmBTU/hour and the annual operating hours from 1,000 to 2,000 per year. KDAQ SOB Revision 3 at 2 and 13. As a result of the changes, LG&E conducted a revised BACT analysis for the auxiliary boiler for PM/PM_{10}, CO, VOC, and SAM. LG&E did not conduct BACT analyses for NO_x or SO_2 due to its determination that LG&E netted out of BACT for the major modification project as a whole. As part of the Revision 3 changes, the permit was modified to require the use of ultra low-sulfur diesel fuel and low NO_x burners (Revision 2 required use of low-sulfur fuel oil). *Id.* KDAQ determined that these were "BACT-level" controls. Permit Revision 3 at 37; KDAQ SOB Revision 3 at 13. With regard to emissions resulting from the Revision 3 changes, KDAQ explained that emissions of all pollutants with the exception of CO, lead, and fluorides decreased as a result of the proposed changes. KDAQ SOB Revision 3 at 6. The SOB explains that the net emissions increase for CO for the Revision 3 modifications is 9.4 tpy. KDAQ SOB Revision 3 at 5. As part of KDAQ's Revision 3 review, "[t]he Division reevaluated BACT for the project revisions and [sic] determined that the BACT emission limits established in the January 2006 permit remain unchanged." KDAQ SOB Revision 3 at 10. The SOB includes more specific information for the revised BACT analysis for the affected units and pollutants. KDAQ SOB Revision 3 at 11-15.

In Petition 1, Petitioners raise concerns that the BACT analysis for the auxiliary boiler should have included consideration of low-sulfur coal, coal blend, or natural gas (as opposed to fuel oil). The auxiliary boiler is not burning coal; thus, Petitioners' statements regarding coal are misplaced because coal would typically result in higher emissions than fuel oil (particularly the proposed Grade No. 2-D S15 or equivalent fuel oil). *See, e.g.*, AP-42 Compilation of Air Pollutant Emission Factors, Stationary Point and Area Sources, Fifth Edition, at Chapter 1, Tables 1.1-3 (coal), 1.3-1 (oil), and Appendix A-6 (heating values). Petitioners fail to provide any information supporting why low-sulfur coal should be part of the BACT analysis for the auxiliary boiler.[28] Petition 1 at 26-27. As a result, Petitioners have not demonstrated that the BACT analysis for the auxiliary boiler was required to consider coal options. In response to Petitioners' comments regarding natural gas, KDAQ responded that, "[t]here is a negligible difference in PM, VOC, and CO emissions from a 40 mmBTU/hour boiler firing natural gas versus one firing oil." KDAQ RTC Revision 2 at 25. KDAQ explained the basis of the "negligible difference" as stemming from AP-42 emissions factors, noting that such factors do not take into consideration use of low-sulfur fuel and operational limits (i.e., the 1,000 hour annual operating limit contained in Revision 2). *Id.*

In Petition 2, Petitioners claim that the changes made as part of Revision 3 (increasing the size and hours of operation) required a revised BACT analysis for the auxiliary boiler. The only

[28] In addition, coal blends for the auxiliary boiler were not a part of the LG&E application.

PSD pollutant that was increased as a result of the Revision 3 changes was CO. In the response to comments for Revision 3, KDAQ explains, "The prior BACT determination was based on a top down BACT analyses for carbon monoxide (CO). The proposed design and operation of the [auxiliary] boiler continues to constitute BACT." KDAQ RTC Revision 3 at 18. However, this statement is not consistent with KDAQ's response to comments on Revision 2, wherein the BACT analysis for CO emissions from the auxiliary boiler was specifically based on the size and operating hours of the auxiliary boiler. KDAQ RTC Revision 2 at 25. While EPA appreciates that a 100 mmBTU/hour boiler is a small industrial boiler, KDAQ's reliance on the 40 mmBTU/hour boiler size and a limit of 1,000 annual operating hours as a basis to support the Revision 2 BACT analysis raises questions concerning KDAQ's reliance on the Revision 2 BACT analysis to support the Revision 3 changes, because those changes included increases to both the boiler size and the operating hours.

Thus, EPA is granting Petitioners' request with regard to the auxiliary boiler and requiring KDAQ to perform a revised BACT analysis for the Revision 3 changes, including the increase in size and operating hours. As noted earlier, KDAQ's Revision 2 BACT analysis indicated a "negligible" difference in the use of natural gas for certain pollutants, so whether a "negligible" difference would still exist in light of the Revision 3 changes should be addressed as part of KDAQ's revised BACT analysis. This analysis should be documented in the SOB. Should any changes to permit conditions be necessary following the revised analysis, a permit revision will be necessary to incorporate those changes.

5. Petitioners' Claims Regarding the BACT Analysis for Support Operations at the Facility
(Section II.H. of Petition 1 – Partial Response)

Petitioners' Claims. Petitioners allege that EPA must object to the permit because the limits set for "various pollutants at various facilities" are not BACT. Petition 1 at 27. For this proposition, Petitioners cite to 401 KAR 51:017 § 8 ("Control Technology Review"). This allegation is followed by a bulleted list of three one-sentence statements alleging that (1) permit limits for various support facilities at the Trimble County facility are not BACT; (2) permit limits for fluorides (HF) are not BACT; and (3) permit limits for SAM are not BACT. Petition 1 at 27-28. Petition 1 is not clear whether issues 2 and 3 are related to the proposed new unit or the support facilities listed in the first bullet (coal blending, material handling operations, ash barge loading, fly ash silos, backup diesel generator, and the emergency diesel fire water pump). Because the one-sentence introducing the bulleted list refers to "various pollutants at various facilities," coupled with the prior independent sections specific to the proposed new unit, EPA concludes that Petitioners' claims in the bulleted list all regard the support facilities listed in the first bullet. In an Order issued on September 10, 2008, EPA responded to all the issues except those relating to the backup diesel generator and the emergency diesel fire water pump because those support facilities were affected by Revision 3. *See* Order 1 at 11-12. We respond to these remaining issues below.

EPA's Response. As a threshold procedural matter, these issues were not raised during the public comment process for this permit. Petitioners' Exhibit A. Nor do Petitioners claim that it was impracticable to raise such claims during the public comment period or that the grounds for the claims arose after the close of the comment period. Thus, Petitioners failed to meet threshold requirements described in Section 505(b)(2) of the CAA, for raising these issues for the first time in a Petition to the Administrator.

Although we are not required to respond to these issues in light of the procedural deficiencies, we nevertheless respond briefly to the substance of the issue. As part of the permit analysis, KDAQ undertook a BACT analysis for project emission units subject to PSD requirements. KDAQ SOB Revision 2 at 23-24. KDAQ SOB Revision 2 at 14. In addition, KDAQ's BACT analysis for the new boiler included a BACT analysis for support facilities that were considered "project emission units" – that is, support facilities that were subject to PSD review as a result of the new boiler project. KDAQ SOB Revision 2 at 23-24; *see also* 401 KAR 51:001 § 1(66) (definition of emissions unit). KDAQ determined that support facilities such as limestone handling, the backup diesel generator (also referred to as the "emergency generator"), and the emergency diesel fire water pump, were subject to BACT review. KDAQ SOB Revision 2 at 23-24. In Revision 3 to the permit, the emergency diesel fire water pump was eliminated. KDAQ SOB Revision 3 at 14. Thus, issues associated with this support facility are now moot. With regard to the backup diesel generator, KDAQ did review the BACT analysis previously done for that support facility as part of its Revision 3 review. KDAQ SOB Revision 3 at 14. As part of Revision 3, the backup diesel generator will use ultra low sulfur diesel (or equivalent) fuel and the hours of operation are limited to 52 per year. KDAQ determined that these limitations constituted BACT for this unit. KDAQ SOB Revision 3 at 14.

Petitioners did not raise any additional concerns about the BACT analysis for support facilities in Petition 2. In addition, in Petition 1, Petitioners provided no basis as to why the BACT analysis performed by KDAQ for the identified facilities was inconsistent with applicable requirements. Petitioners' conclusory allegations regarding the permit are insufficient to demonstrate that the permit is inconsistent with the CAA, including the requirements of the SIP. For the reasons discussed above, the Petition 1 is denied as to this issue.

6. *Petitioners' Claims Regarding BACT for PM*
(Section V.c. of Petition 2 and II.C. of Petition 1)

Petitioners' Claims. Petitioners raise concerns regarding the PM/PM_{10} BACT analysis in Petitions 1 and 2 and all of these issues are being addressed in this Order. In Petition 1, Petitioners state that the permit fails to require BACT for both PM and PM_{10} at Unit 31 by solely containing a BACT limit for "particulate emissions." Petition 1 at 18. Further, Petitioners allege that lower PM/PM_{10} limits are achievable at the facility and were incorrectly eliminated as BACT by the applicant; Petitioners cite to limits allegedly achieved at other facilities to demonstrate this point. Petition 1 at 19. Petitioners state that the PM/PM_{10} limits for the new and existing cooling towers are also not BACT (including the drift elimination rate). Petition 1 at 21. Finally, Petitioners explain specific concerns regarding the BACT analysis, such as claiming KDAQ performed an improper cost analysis.

In Petition 2, Petitioners' issues are primarily related to the installation of the DESP, and whether a facility's decision to include additional controls after a BACT analysis is completed implicates the prior BACT analysis. Petition 2 at 31-33. First, Petitioners suggest that the addition of the DESP invalidates the prior BACT analysis. Second, Petitioners explain that the BACT limit for PM/PM10 should be based on both the PJFF and DESP, which together, would be expected to result in a decrease of PM/PM10 emissions. *Id.* Petitioners cite to LG&E's application materials to support their contentions that the combined control efficiency for PM will improve and thus, the previous BACT analysis did not represent the "maximum degree of control that is available." Petition 2 at 32.

EPA's Response to Petition 1 Issues

a. Distinction between PM and PM_{10}

Petitioners state that it is unclear whether the limits in the permit are set for PM or PM_{10}. PM and PM_{10} are regulated as separate pollutants,[29] but they are very similar in terms of control technology, emission points, and emission rates. As a result, the BACT analyses for these pollutants is often similar, and there is nothing that precludes the analysis resulting in the same limit and/or BACT-level controls for each pollutant. *See, e.g., Prairie State*, slip op. at 3, 106-107 (explaining a PM BACT analysis). Kentucky's SIP-approved rules at 401 KAR 51:001 § 1(181) defines particulate matter but does not specify a size diameter. PM_{10} is separately defined in 401 KAR 51:001 § 1(186). In the permit record, KDAQ explained that "Kentucky's regulation is clear that PM_{10} is a subset of particulate matter." KDAQ RTC Revision 2 at 20. The SOB for Revision 2 groups PM and PM_{10} together under the name "particulate matter," which indicates Kentucky's evaluation involved both pollutants. KDAQ SOB Revision 2 at 18. Further, the permit sets limits for both PM and PM_{10}, although the same limit is used. Permit Revision 3 at 28 (0.018 lbs/mmBTU (filterable and condensable) based on the average of three one-hour tests). Accordingly, the record indicates that KDAQ considered both pollutants although they were evaluated together with emissions of PM_{10} considered as a subset of PM. KDAQ RTC Revision 2 at 20. The permit includes a BACT limit for PM and PM_{10} – KDAQ and LG&E undertook the required analysis and determined that the two limits were the same, which is not uncommon. KDAQ SOB Revision 2 at 18-20; *see also* 2004 Application at Section 3.0, Appendix I (Part 5.0 – "Particulate Emissions Control"). Petitioners have thus failed to demonstrate that the analysis performed by KDAQ was inconsistent with applicable requirements.

b. Concerns that the PM/PM_{10} limits are not BACT

Petition 1 also raises concerns with the emission limits set for PM/PM_{10} and suggests that they are not BACT, in part because several other facilities noted in Petition 1 were issued permits with allegedly lower PM and/or PM_{10} limits. As a general matter, the 2004 Application and the SOB explain the BACT analysis done by LG&E and KDAQ for this permit. 2004 Application at Section 3.0, Appendix I pgs. 14-23; KDAQ SOB Revision 2 at 18-20. For Unit 31, Section B.2(a) (Permit Revision 3 at 28) lists the PM/PM_{10} limits for both filterable and condensable. Permit Revision 3 at 28. These limits also include those imposed by federal New Source Performance Standards (40 CFR Part 60, Subpart Da). *Id.* In addition, KDAQ

[29] PM_{10} is a subset of particulate matter, i.e., it is particulate matter that is less than 10 micrometers in size.

considered the other facilities identified by Petitioners in their comments to Kentucky during the Commonwealth's public comment period, and KDAQ responded to Petitioners' allegations for each of the facilities cited by Petitioners. KDAQ RTC Revision 2 at 21; *see also* 2004 Application Appendix I-14 (for discussion of other facility control mechanisms). KDAQ's response includes a reasoned basis for distinguishing each of the cited facilities from the LG&E situation. *Id.* Specifically, KDAQ's RTC points out factual differences between LG&E and the facilities noted by Petitioners. In some cases, Petition 1 notes these differences, but Petitioners disagree with KDAQ about their impact on the analysis. Generally, however, Petition 1 raises the exact same claims to EPA that they raised to KDAQ during the permit process but fails to explain or demonstrate how KDAQ's responses were unreasonable or inconsistent with applicable requirements. Petition 1 at 18-22. The permit record demonstrates that KDAQ considered Petitioners' comments and provided a response that supports the PM/PM_{10} limits in the LG&E permit. Because Petitioners have made no claim to EPA explaining why KDAQ's reasoned responses to their concerns are insufficient, or how the analysis was otherwise inadequate, they have failed to demonstrate that the permit is not consistent with applicable requirements, or that there is a flaw in the permit with regard to the PM/PM_{10} limits.

c. Concerns regarding the cooling towers, PM limits, and drift elimination rate[30]

The LG&E Trimble facility has one existing natural draft cooling tower (Unit 20) and, as part of the construction on Unit 31, LG&E proposed to construct a new linear mechanical draft cooling tower (Unit 41). KDAQ SOB Revision 2 at 1. KDAQ performed a BACT analysis associated with construction of Unit 31 for both the cooling towers because it was anticipated that Unit 20 may be used for Unit 31 until construction on Unit 41 is completed. KDAQ SOB Revision 2 at 23. KDAQ's BACT analysis for the cooling towers resulted in a drift elimination rate but not a specific PM/PM_{10} limit. With regarding to the cooling towers, Petitioners raise the following concerns: (1) the permit fails to set a PM/PM_{10} emission limit for Unit 41; (2) the proposed drift elimination rate for Unit 41 does not represent BACT; and (3) the BACT analysis performed by KDAQ for Unit 41 was not adequate because KDAQ failed to consider a high efficiency drift eliminator and the cost analysis was not correct. Petition 1 at 21-22.

There is no PM/PM_{10} "limit" for the cooling towers identified in the permit because particulate matter from a cooling tower is typically controlled by drift elimination as opposed to add-on control technology. In the RTC, KDAQ explained that "[p]articulate matter from cooling towers is generated by the presence of dissolved and suspended solids in the cooling tower circulation water, which is potentially lost as 'drift' or moisture droplets that are suspended in the air [move] out of the cooling tower." KDAQ RTC Revision 2 at 27. In its 2004 Application, LG&E explained that through controlling drift rate, LG&E would be able to limit PM/PM_{10} emissions. 2004 Application at Appendix I-31. Accordingly, the permit does contain a limit on PM/PM_{10} emissions from the cooling towers through the application of the drift rate.

[30] Petitioners appear to raise several cooling tower related concerns – some of which pertain to Unit 20 and some to Unit 41, although Petition 1 is not always clear on this point. EPA has made a good faith, reasonable effort to identify Petitioners' issues vis-à-vis the appropriate cooling tower.

For the two cooling towers, the permit sets a drift elimination rate (0.0005%), a circulating water rate, and references Kentucky rules regarding visible fugitive dust and particulate matter (Permit Revision 3 at 20, 48; 401 KAR 63:010). This appears consistent with what Petitioners requested during the permit process and is the same as the issues they raised to EPA in Petition 1. Petition 1 at 22. The draft permit for Revision 2 had higher drift elimination rates for both Units 20 and 41, set at 0.0008% and 0.001%, respectively. Draft Permit Revision 2 at Section B (Emission Units 20 and 41). The current permit has a lower drift elimination rate for both units – set at 0.0005% (for Unit 20, this rate only applies when servicing Unit 31). Permit Revision 3 at 20 (Unit 20); Permit Revision 3 at 48.[31] With regard to that rate, KDAQ stated that the drift rate of 0.0005% represents the most stringent level of drift elimination proposed as BACT for the type of cooling tower at LG&E (a linear mechanical draft cooling tower). KDAQ RTC Revision 2 at 27. As the drift elimination rate contained in Revision 3 is consistent with that identified by Petitioners in Petition 1, this issue was thus resolved by KDAQ in the permitting process.

Petitioners also raise concerns regarding the BACT analysis which resulted in the drift rate. KDAQ performed a BACT analysis for Unit 41, reviewed LG&E's analysis, and reached determinations regarding BACT limits for the cooling towers. KDAQ SOB Revision 2 at 23; 2004 Application at Appendix I-30 - I-35. As part of this analysis, LG&E conducted a review of the RBLC Clearinghouse[32], and considered drift rates from a variety of facilities in Kentucky, Washington, and West Virginia. 2004 Application at Appendix I-30. LG&E then evaluated the alternative cooling tower systems and reached the conclusion that the drift rate of 0.0008% represented BACT. *Id.* at I-31. LG&E concluded that this rate could be met with the linear mechanical draft cooling tower for Unit 41, along with a lower drift rate on Unit 20. Ultimately, the permit drift rate limit was set at 0.0005%. Permit Revision 3 at 48. Petitioners suggest that a high efficiency drift eliminator should have been considered. Petition 1 at 21-22. However, there is no stand-alone device called a "high efficiency drift eliminator." Rather, the cooling towers provide for the air containing particulate to flow through an area with items such as baffles (also referred to as fill media) essentially trying to dislodge the water droplets from the air and allow the water to recirculate into the water flow. 2004 Application at Appendix C-5. The air flow can be forced with a fan, or it can occur naturally. The use of a fan seeks to increase the amount of dislodged droplets. Unit 41 is a linear *mechanical* draft cooling tower and thus utilizes the fan method to dislodge droplets. Because this method was adopted in the final permit, the final permit reflected a rate of 0.0005% rather than the 0.0008% rate in the draft permit. The rate adopted in the final permit is the rate which Petitioners identified as appropriate. Petition 1 at 22. Thus, it appears that this particular issue was resolved by KDAQ during the permitting process.

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[31] Following the public comment period on the permit, KDAQ added requirements for LG&E to monitor and record monthly total dissolved solids to the permit. KDAQ RTC Revision 2 at 27.
[32] The RBLC is the reasonably available control technology (RACT), best available control technology (BACT), Lowest Achievable Emission Rate (LAER) Clearinghouse – commonly referred to as the RBLC Clearinghouse.

Also with regard to the BACT analysis for Unit 41, Petitioners raise concerns about the cost analysis. Petitioners suggest that the cost allocation in terms of the cooling system as a whole versus just the "control" element was not accurate. Petition 1 at 22. Petitioners analogize this to considering the cost of a boiler in the BACT analysis for NO_x while also considering the addition of an SCR. Petition 1 at 22. The cost analysis is summarized in the 2004 Application at I-34 - I-35. Appendix C provides additional specifications on the cooling towers and the associated costs. LG&E did include cost analysis (and PM reductions) as part of the review, and identified an appropriate BACT limit for Units 41 and 20. Although the LG&E BACT analysis does not specifically address Petitioners' point, LG&E did consider dry cooling among other technologies. When considering dry cooling, a completely distinct type of cooling tower is at issue (as opposed to a wet cooling tower). 2004 Application at I-34 - I-35. Further, the technology of drift control is such that even incremental improvement in drift control can involve substantial changes in the cooling tower design. *See, e.g.,* AP 42 Compilation of Air Pollutant Emission Factors, Stationary Point and Area Sources at Chapter 13.4 (discussing wet cooling towers and fluctuations in drift depending on design). For example, adjusting air velocity may result in the need for a smaller passageway. Such adjustments also trigger other issues, such as a possible increase or decrease in the heat transfer coefficient of the tower. Thus, the relationship between a cooling tower and the drift elimination technique can be distinguished from that of a boiler and a conventional add-on control device such as an SCR (where the boiler design does not directly implicate the SCR design). The BACT analysis for the cooling towers performed by LG&E and KDAQ considered the cost of the cooling tower as whole which Petitioners have not demonstrated is an unreasonable approach in this factual context. Further, as noted earlier, KDAQ revised the permit to include the lower drift elimination rate sought by Petitioners. As a result, Petitioners have not identified a flaw in the permit and the Petition is denied as to this issue.

For the reasons discussed above, Petitioners failed to demonstrate that the permit is inconsistent with the CAA, or Kentucky's SIP-approved rules. Therefore, Petition 1 is denied with regard to the matters discussed above.

EPA's Response to Petition 2

In Petition 2, Petitioners' issues are primarily related to the installation of the DESP in Permit Revision 3, and whether a decision to include additional controls after the BACT analysis for Permit Revision 2 was completed implicates that prior BACT analysis. Petition 2 at 30-33. First, Petitioners suggest that the addition of the DESP invalidates the prior BACT analysis. Second, Petitioners explain that the BACT limit for PM/PM_{10} should be based on both the PJFF and DESP, which together, Petitioners argue, would be expected to result in a decrease of PM/PM_{10} emissions. *Id.* An overview of the BACT analysis process, as well as the BACT definition, are discussed on page 13 of this Order. As part of the Revision 2 application, LG&E conducted a top-down BACT analysis consistent with applicable requirements for Unit 31. 2004 Application at Appendix I at I-14-I-23. This analysis included the consideration and elimination of a DESP through a top-down BACT methodology. *Id., see also* KDAQ SOB Revision 2 at 18-20. Petitioners raised no concerns with the elimination of the DESP from the PM/PM_{10} BACT analysis at that time.

With regard to Petitioners' first argument – that the BACT analysis is reopened because of the addition of the DESP – Petitioners cite to no support for this conclusion. In fact, there is nothing in the CAA or any other applicable requirement that suggests that merely because a company voluntarily installs a particular control device, that any prior BACT determination is automatically invalidated. The nature of the BACT determination is that control technology may in fact be eliminated through the analysis for a number of reasons including technical or economic infeasibility. *See, e.g.*, 42 U.S.C. § 7479 (3); 40 CFR § 52.21(b)(12). Contrary to Petitioners' assertion, the BACT analysis does not require facilities to add on every possible control technology – but rather, to establish an emission limitation based on the maximum degree of reduction for each pollutant, taking into account energy, environmental, economic impacts, and other costs.[33] *Id.* In the preamble to EPA's 1974 new source review rulemaking, EPA made specific changes to underscore that in the BACT analysis, the emphasis is on the "emissions rather than the presence of any particular control equipment." 30 *Fed. Reg.* 42510, 42514 (December 5, 1974). Further, in 1979, EPA issued a Memorandum entitled, *Guidance for Determining BACT Under PSD*, addressing this issue. Memorandum from David G. Hawkins to Regional Administrators, I-X, *Guidance for Determining BACT Under PSD*, January 4, 1979. Specifically, in the portion of the Memorandum discussing presentation of alternative systems that could achieve a higher degree of emission control, the Memorandum explains,

> [i]f no better control technology is available for an emission point, then such finding should be stated and supported, and <u>no further analysis is required</u>. Other equipment with similar control capabilities need not be presented (e.g., a baghouse versus an equivalent ESP at a particulate emitter). Unrealistic alternatives need not be presented such as placing in series control equipment which is normally used alone (e.g., an ESP followed by a baghouse).

Id. at 6 (emphasis in original). Thus, there is no basis in the CAA or its implementing regulations (or Kentucky law) for the proposition that a prior BACT analysis is automatically invalidated by the subsequent addition of control technology for a non-PSD purpose (and where the addition does not trigger PSD review).

As KDAQ explained, the DESP was added as part of Revision 3 to "ensure that saleable fly ash is captured prior to potential contamination due to [powdered activated carbon] injection for mercury control." KDAQ SOB Revision 3 at 2. Thus, the addition of the DESP has no direct relationship to prior BACT analysis done as part of Revision 2. *See also* 42 U.S.C. § 7412(b)(6) (specifically excluding hazardous air pollutants, including mercury, from PSD review). In response to Petitioners' comment, KDAQ stated,

> Revision 3 does not involve any modification of Emission Unit 31. Therefore, Emission Unit 31 BACT limit for PM is not under review in this permitting action. The project revisions have resulted in insignificant changes to the project's original potential-to-emit as specified in the Statement of Basis Table

[33] BACT is distinguishable from its more stringent, nonattainment new source review counterpart, "lowest achievable emission rate" or LAER. *See, e.g.*, 42 U.S.C. § 7501(3).

> 3.4. Additionally, the PSD applicability on a pollutant-by-pollutant basis and the associated BACT determination for new equipment remain unchanged.

KDAQ RTC Revision 3 at 17. Because the DESP was added to control mercury emissions, the addition does not affect the Revision 2 BACT analysis. KDAQ noted this point in explaining in the SOB for Revision 3 that, "the installation of the DESP does not affect the BACT emission limits for particulate...or filterable particulate...established in the January 2006 Permit...for Emission Unit 31." KDAQ SOB Revision 3 at 12. In this case, Revision 3 was not changing a fundamental parameter of the BACT analysis. Rather, the Revision was including an additional control device for a purpose unrelated to BACT (to result in a saleable fly ash per added mercury controls). Further, there is no indication that the addition of the DESP is a "PSD-triggering" event – that is, emissions are not expected to increase as a result of the addition of a DESP, nor is the DESP expected to impact the facility's compliance with the previously established PM/PM_{10} BACT limit. Notably, both LG&E and KDAQ reviewed the Revision 2 BACT analysis following LG&E's decision to add the DESP as part of Revision 3. For the reasons discussed below (and in greater detail in the 2007 Application), the PM/PM_{10} limits established through the Revision 2 BACT analysis were not changed. Thus, in this case, Petitioners have not demonstrated that the BACT analysis was affected by the addition of the DESP.

Petitioners also suggest that the PM/PM_{10} limit should have been revised because the addition of the DESP "is likely to result in appreciably lower particulate matter emissions than a fabric filter alone." Petition 2 at 32. To support this claim, Petitioners make a series of mathematical calculations; however, as is explained below, a closer look at their analysis shows that Petitioners failed to take into account a number of operational characteristics of fabric filters and DESPs. Further, as was discussed above, the BACT limit is not intended to be the most stringent limit possible (that is, BACT is not the "lowest" achievable emission rate). Thus, even if the addition of the DESP is likely to reduce PM/PM_{10} emissions, Petitioners cite to no authority for the suggestion that the BACT determination must be revisited or the PM/PM_{10} limit must be reduced merely because it could be reduced. In the Revision 2 application, LG&E explains its decision regarding PM/PM_{10} control devices as follows:

> While the bag life of a fabric filter baghouse in this application is uncertain, the use of a fabric filter baghouse instead of an ESP is selected based on the ability of the fabric filter baghouse to maintain emission levels independent of ash characteristics, to provide additional control of mercury and SO_3, to allow lower levels of absorbent/reagent use for mercury and H_2SO_4 while providing greater control, and the fact that fabric filter baghouses have been the technology of choice in recent permits for similar applications.

2004 Application at Appendix I-22. As part of the BACT analysis in Revision 2, LG&E considered a baghouse and ESPs, and decided upon the chosen technology based on the appropriate top-down analysis. In Revision 3, LG&E decided to add a DESP for the following reason:

> [t]he refined design determined the installation of a new dry [ESP] (DESP) for Unit 2 [a/k/a Unit 31] is necessary to separate fly ash out of the Unit 2 exhaust gas

stream prior to the potential injection of PAC. Without the additional dry ESP, fly ash from Unit 2 could never be sellable because of the carbon from the control of mercury emissions...Also, the dry EP reduces the amount of potentially mercury contaminated fly ash. The dry ESP will be located between [Unit 31's] SCR and fabric filter baghouse, thus allowing for the removal of sellable/usable fly ash if that becomes a potential alternative in the future. The addition of the DESP will not affect the permitted particulate emission rate of 0.018 lb/mmBTU, as described in Condition 2a for Emission Unit 31 from the Final Qir Quality Permit issued on January 4, 2006. The addition of the DESP will also not affect the filterable particulate emission rate of 0.015 lb/mmBTU, as described in Condition 2b for Emission Unit 31 from the Final Air Quality Permit issued on January 4, 2006. The DESP will not change the flow or temperature as presented in the 2004 Application. The physical structure of the DESP and the affect of the incorporation of the DESP to the air pollution control technologies were reviewed and incorporated into the downwash for the air dispersion modeling.

2007 Application at 2-10. In this context, the DESP is not intended to achieve a greater reduction of PM/PM_{10}, although KDAQ estimates an "insignificant coincidental benefit" is possible. KDAQ SOB Revision 3 at 23. The reason for this expectation is based in part on the operation of the fabric filter. As explained by LG&E in the 2004 Application, a fabric filter's efficiency for controlling particulate emissions is based upon the buildup of cake and the pressure associated with this buildup. 2004 Application at Appendix I-18. "The collected particulate forms a cake on the bag, which can enhance the bag's filtering efficiency." *Id.* With the addition of the dry ESP before the fabric filter, even the small reduction in particulates from the dry ESP may have an impact on the efficiency of the fabric filter such that the ultimate particulate emissions may remain unchanged. Petitioners' basic calculations in Petition 2 do not take into consideration the potential decrease in efficiency of the fabric filter due to the addition of the dry ESP. Petition 2 at 32. Nonetheless, as was discussed earlier, the addition of the DESP was not a PSD-triggering event and Petitioners fail to demonstrate that a new BACT limit for PM/PM_{10} was required by applicable law. For the reasons discussed above, Petitioners have not demonstrated that in Revision 3, the permit fails to comply with the applicable requirements. Therefore, Petition 2 is denied as to the issues discussed above.

7. Petitioners' Claims Regarding BACT for SAM, PM/PM_{10}, and Ammonia

(Section V.e. Petition 2; Section II.G. Petition 1)

Petitioners' Claims. Petitioners raise concerns regarding BACT for SAM in both Petitions. In Petition 1, Petitioners suggest that the Revision 1 Minor Modification resulted in an increase of SAM emissions of 7 tpy, thus triggering a BACT analysis for SAM (Petitioners also raise similar concerns regarding PM/PM_{10} at Unit 1 and ammonia emissions at Units 1 and 31). Petition 1 at 27. In Petition 2, Petitioners claim that the BACT analysis for SAM was not supported because, according to Petitioners, LG&E reviewed the RBLC and then concluded the BACT limit was based on a WESP; LG&E provided no supporting calculations nor did LG&E explain its assumptions; and that the "lowest emissions level achievable" by this facility was not achieved. Petition 2 at 37-38.

EPA's Response to Petition 1

In Petition 1, Petitioners suggest that the minor modifications undertaken at Unit 1 to decrease emissions of NO_x and SO_2 for netting purposes triggered major PSD review because of increases of SAM and PM/PM_{10}, as well as resulting in increases of ammonia at Units 1 and 31. Specifically, Petitioners state that the decreases of NO_x and SO_2 caused an increase in SAM of 7 tpy and an increase in PM/PM_{10} of 15 tpy. Petition 1 at 27. Petitioners provide no data or analysis to support these statements.[34] The SOB for Revision 1 (Minor Modification) includes a discussion of the creditable decreases of NO_x and SO_2 from Unit 1, as well as a BACT analysis for the six simple cycle natural gas-fired combustion turbines, which did involve significant emissions increases. However, the Revision 1 (Minor Modification) SOB does not indicate that there will be any increases in PM/PM_{10} or SAM as a result of the Unit 1 decreases in NO_x and SO_2. As was discussed earlier, new control technology was not installed for the reductions – the reductions were achieved through increased efficiency of the existing control devices. With regard to the ammonia issues, ammonia is not a PSD regulated pollutant and thus, assuming there were increases in ammonia emissions, there is no obligation for KDAQ to consider those as part of the PSD review process.[35] With regard to the new Unit 31, KDAQ did undertake a BACT analysis that involved SAM and PM/PM_{10}, among other relevant pollutants. KDAQ SOB Revision 2 at 14; *see also* 2004 Application at Appendix I. Petitioners have thus failed to present any information demonstrating that Units 1 or 31 are not properly permitted for SAM, PM/PM_{10}, and ammonia.[36]

EPA's Response to Petition 2

As part of the 2004 Application, LG&E conducted a BACT analysis for SAM emissions associated with the new Unit 31 and other modifications. 2004 Application at Appendix I-27 - I-29. The Application explains that LG&E reviewed the RBLC and considered emission limits at other sources in Kentucky and West Virginia. *Id.* at I-27. LG&E also considered various alternative sulfuric acid emission reduction systems. *Id.* Emission rates associated with the modifications are also discussed in the 2004 Application in Appendix G, "Potential to Emit

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[34] Section 505(b) of the CAA requires that Petitioner make a demonstration that the permit is not in compliance with the requirements of the Act. 42 U.S.C. § 7661d(b). A demonstration thus requires more than mere conclusory allegations. *In the Matter of Al Turi Landfill, Inc.*, Petition No. II-2002-13-A (January 30, 2004); *see also, In the Matter of the New York Organic Fertilizer Company*, Petition No. II-2002-12 at pages 7-8 (May 24, 2002); *In the Matter of Sirmos Division of Bromante Corp.*, Petition No. II-2002-03 at page 7 (May 24, 2002). Broad generic claims "lack sufficient specificity" to satisfy these criteria and will be not be reviewed. *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 239-240 (EAB 2000).

[35] To the extent that Petitioners were attempting to demonstrate that the increase in ammonia demonstrated an increase in SAM, this conclusion is not supported by the record, and Petitioners provide no documentation for such proposition.

[36] Unit 1 was permitted for construction prior to September 1978, and as a result, the emission limits applicable to that Unit are not the same as the ones applicable to the proposed new Unit 31. KDAQ SOB Revision 1 (minor modification) at 2.

Calculations." LG&E supported its decision to evaluate sulfuric acid emission reduction equipment by explaining the relationship between sulfuric acid and SAM. *Id.* at I-27. As part of the BACT analysis, LG&E considered semi-dry scrubber systems; WESP; alkali injection systems; as well as SCRs and baghouses. *Id.* at I-27 - I-29. LG&E concluded that the BACT limit for SAM could be achieved with the use of good combustion controls and a WESP downstream from the WFGD controls. *Id.* at I-29. These controls were chosen in part because of their anticipated collateral reductions of PM/PM_{10} and mercury. *Id.* The permit includes a SAM emissions limit for Unit 31 of no greater than 26.6 lbs/hr based on a three (3) hour rolling average. Permit Revision 3 at 29 (Section B.2.(j)). The permit also includes a Compliance Assurance Monitoring (CAM) Approach for SAM. Permit Revision 3 at 32 (Section B.4.(j)). This analysis was consistent with a top-down BACT analysis because LG&E (1) identified all available control technologies; (2) eliminated technically infeasible options; (3) ranked remaining control technologies by control effectiveness; (4) evaluated the economic, environmental, and energy impacts of the options; and (5) selected BACT. *Prairie State*, slip op. at 17-18.

In Petition 2, Petitioners make additional statements regarding this BACT analysis. First, Petitioners state that "BACT does not ask what other plants are currently achieving, but what can this plant achieve for the future." Petition 2 at 36. There is nothing in the CAA or federal rules, or in the Kentucky rules, that requires the BACT analysis to assess the control that might be applied in the future. As was discussed earlier in this Order, the BACT analysis compares options available at the time of the permitting analysis and takes into account facility-specific factors to determine what is BACT. 40 CFR § 52.21(b)(12); 401 KAR 51:001 § 1(25). Petitioners next state that the SAM limit does not represent the "lowest emissions level achievable by this plant as required by the BACT regulations." Petition 2 at 38. However, the BACT process is not required to result in the development of the "lowest emissions level achievable." Petitioners appear to be intertwining the definitions of BACT and LAER. LAER, which is the standard used in nonattainment areas, is distinct from the BACT methodology and is intended to result in the <u>lowest</u> achievable emissions rate. LAER also does not allow the consideration of certain factors that are allowed under the BACT analysis. *See, e.g.*, 40 CFR Part 51, Appendix S, Section II (18); *see gen'lly*, 44 *Fed. Reg.* 3,274 (January 16, 1979). LG&E did not evaluate LAER for this facility, nor was it required to by any applicable requirements. LG&E did evaluate BACT, and a summary of that review is discussed above.

As described above, the 2004 Application contains a BACT analysis following the top-down analytical methodology. This analysis is also described and discussed in the KDAQ SOB for Revision 2. These documents contain far more than a "conclusion" that BACT is a limit of 26.6 lbs/hr as Petitioners suggest (Petition 2 at 37). In terms of the supporting calculations, the 2004 Application describes the specific calculations performed by LG&E to support the BACT conclusion. *See, e.g.,* Appendices I and G. Contrary to Petitioners' suggestion, and as explained above, the BACT analysis performed by LG&E and KDAQ went beyond simply reviewing the RBLC and comparing the LG&E facility to other facilities in Kentucky and West Virginia. Petition 2 at 38. It also considered what could be achieved at the LG&E facility considering facility-specific factors. For the reasons discussed above, Petitioners have failed to demonstrate that the permit is inconsistent with applicable requirements. Therefore, the Petitions are denied as to the issues discussed above.

8. *Petitioners' Claims Regarding Consideration of $PM_{2.5}$* (Section VI Petition 2)

Petitioners' Claims. Petitioners raise a number of concerns regarding $PM_{2.5}$. Petition 2 at 38-46. Specifically, Petitioners argue that LG&E may not meet its obligations for $PM_{2.5}$ by using PM_{10} as a surrogate; that the LG&E permit cannot lawfully issue without quantification of $PM_{2.5}$ emissions; that the permit failed to contain an air quality analysis for $PM_{2.5}$; and that the permit failed to contain a BACT determination for $PM_{2.5}$.

EPA's Response. EPA grants the Petition on this issue to require further consideration of $PM_{2.5}$. Petitioners' concerns regarding $PM_{2.5}$ raise the threshold issue of whether LG&E may use the PM_{10} surrogate approach to meet the PSD requirements for $PM_{2.5}$. As discussed below, the permit record does not provide an adequate rationale to support the use of the PM_{10} surrogate approach for this permit. As the other concerns raised by Petitioners relate at least in part to whether KDAQ's use of PM_{10} as a surrogate was appropriate, EPA directs KDAQ to address these claims as well.

Petitioners make several arguments to support their view that KDAQ's use of PM_{10} as a surrogate for $PM_{2.5}$ was not appropriate. While EPA does not necessarily agree fully with all of Petitioners arguments, two points raised by Petitioners are particularly persuasive. First, Petitioners essentially argue that KDAQ's permit record does not, as a technical matter, provide support for the use of PM_{10} as a surrogate for $PM_{2.5}$. *See, e.g.*, Petition 2 at 40. Second, while they disagree with the use of the surrogate policy as a general matter, Petitioners emphasize that even the surrogate policy was only intended for use until technical difficulties associated with analysis of $PM_{2.5}$ have been resolved. *See, e.g.*, Petition 2 at 43-45. EPA addresses and elaborates on these and related difficulties with KDAQ's record on this issue below.

Background on $PM_{2.5}$ NAAQS and CAA

EPA establishes NAAQS for certain pollutants, pursuant to Section 109 of the CAA, 42 U.S.C. § 7409. Once a NAAQS is established, the CAA sets forth a process for designating areas in the nation as attainment, nonattainment, or unclassifiable, thus triggering additional requirements consistent with the CAA and its implementing regulations. Following establishment of a NAAQS, EPA also promulgates implementation rules that provide specific details of how states must comply with the NAAQS based on the corresponding designations for areas within the state. Generally, the SIP is the primary means by which states comply with CAA requirements to attain the NAAQS. *See* CAA Section 110(a) and Sections 171 - 193, 42 U.S.C. § 7410(a) and §§ 7501 - 7515.

On July 28, 1997, EPA revised the NAAQS for PM to add new standards for "fine" particulates, using $PM_{2.5}$ as the indicator. 62 *Fed. Reg.* 39,852 (July 28, 1997). On October 17, 2006, EPA revised the NAAQS for both $PM_{2.5}$ and PM_{10}. 71 *Fed. Reg.* 61,236 (October 17, 2006). On October 23, 1997, EPA issued a memorandum from John S. Seitz regarding implementation of the 1997 standards entitled, "*Interim Implementation for the New Source Review Requirements for $PM_{2.5}$*" (Seitz Memorandum). The Seitz Memorandum explained that sources would be allowed to use implementation of a PM_{10} program as a surrogate for meeting $PM_{2.5}$ NSR requirements until certain technical difficulties were resolved. Seitz Memorandum at 1. On April 5, 2005, EPA issued a second guidance memorandum from Stephen D. Page entitled, "*Implementation of New Source Review Requirements in PM-2.5 Nonattainment Areas*" (Page Memorandum), which re-affirmed the October 23, 1997 Memorandum. Page Memorandum at 1. On May 16, 2008, EPA promulgated the final rule entitled "Implementation of the New Source Review (NSR) Program for Particulate Matter Less than 2.5 Micrometers ($PM_{2.5}$) (May 2008 $PM_{2.5}$ NSR Implementation Rule). 96 *Fed. Reg.* 28,321 (May 16, 2008). In the preamble to that rule, EPA explained the transition to the $PM_{2.5}$ NSR requirements beginning on page 28,340. Specifically, EPA concluded that, if a SIP-approved state is unable to implement a PSD program for the $PM_{2.5}$ NAAQS based on that rule, the state may continue to implement a PM_{10} program as a surrogate to meet the PSD program requirements for $PM_{2.5}$ under the PM_{10} Surrogate Policy in the Seitz Memorandum.[37] 96 *Fed. Reg.* at 28,340-28,341.

Use of PM_{10} as a Surrogate for $PM_{2.5}$

When EPA issued the PM_{10} Surrogate Policy in 1997, the Agency did not identify criteria to be applied before the policy could be used for satisfying the $PM_{2.5}$ requirements. However, courts have issued a number of opinions that are properly read as limiting the use of PM_{10} as a surrogate for meeting the PSD requirements for $PM_{2.5}$. Applicants and state permitting authorities seeking to rely on the PM_{10} Surrogate Policy should consider these opinions in determining whether PM_{10} serves as an adequate surrogate for meeting the $PM_{2.5}$ requirements in the case of the specific permit application at issue.

Courts have held that a surrogate may be used only after it has been shown to be reasonable to do so. *See, e.g., Sierra Club v. EPA*, 353 F.3d 976, 982-984 (D.C. Cir. 2004) (stating general principle that EPA may use a surrogate if it is "reasonable" to do so and applying analysis from *National Lime Assoc. v. EPA*, 233 F.3d 625, 637 (D.C. Cir. 2000) that is applicable to determining whether use of a surrogate is reasonable in setting emissions limitations for hazardous air pollutants under Section 112 of the Act); *Mossville Envt'l Action Now v. EPA*, 370 F. 3d 1232, 1242-43 (D.C. Cir. 2004) (EPA must explain the correlation between the surrogate and the represented pollutant that provides the basis for the surrogacy); *Bluewater Network v. EPA*, 370 F.3d 1, 18 (D.C. Cir. 2004) ("The Agency reasonably determined that regulating [hydrocarbons] would control PM pollution both because HC itself contributes to such pollution, and because HC provides a good proxy for regulating fine PM emissions"). Though these court decisions do not speak directly to the use of PM_{10} as a surrogate for $PM_{2.5}$, EPA believes that the overarching legal principle from these decisions is that a surrogate may be used only after it has been shown to be reasonable (such as where the surrogate is a reasonable proxy for the pollutant or has a predictable correlation to the pollutant). Further, we believe that this case law governs the use of EPA's PM_{10} Surrogate Policy, and thus that the legal principle from the case law applies where a permit applicant or state permitting authority seeks to rely upon the PM_{10} surrogate policy in lieu of a $PM_{2.5}$ analysis to obtain a PSD permit.

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[37] The Seitz Memorandum is commonly referred to as EPA's 1997 Surrogate Policy.

With respect to PM surrogacy in particular, there are specific issues raised in the case law that bear on whether PM_{10} can be considered a reasonable surrogate for $PM_{2.5}$. The D.C. Circuit has concluded that PM_{10} was an arbitrary surrogate for a PM pollutant that is one fraction of PM_{10} where the use of PM_{10} as a surrogate for that fraction is "inherently confounded" by the presence of the other fraction of PM_{10}. *ATA v. EPA*, 175 F.3d 1027, 1054 (D.C. Cir. 1999) (PM_{10} is an arbitrary indicator for coarse PM ($PM_{10-2.5}$) because the amount of coarse PM within PM_{10} will depend arbitrarily on the amount of fine PM ($PM_{2.5}$)). In another case, however, the D.C. Circuit held that the facts and circumstances in that instance provided a reasonable rationale for using PM_{10} as a surrogate for $PM_{2.5}$. *American Farm Bureau v. EPA*, 559 F.3d 512, 534-35 (D.C. Cir. 2009) (where record demonstrated that (1) $PM_{2.5}$ tends to be higher in urban areas then in rural areas, and (2) evidence of health effects from coarse PM in urban areas is stronger, EPA reasoned that setting a single PM_{10} standard for both urban and rural areas would tend to require lower coarse PM concentrations in urban areas. The court considered the reasoning from the *ATA* case and accepted that the presence of $PM_{2.5}$ in PM_{10} will cause the amount of coarse PM in PM_{10} to vary, but on the specific facts before it held that such variation was not arbitrary). EPA believes that these cases demonstrate the need for permit applicants and permitting authorities to determine whether PM_{10} is a reasonable surrogate for $PM_{2.5}$ under the facts and circumstances of the specific permit at issue, and not proceed on a general presumption that PM_{10} is always a reasonable surrogate for $PM_{2.5}$

This case law suggests that any person attempting to show that PM_{10} is a reasonable surrogate for $PM_{2.5}$ would need to address the differences between PM_{10} and $PM_{2.5}$. For example, emission controls used to capture coarse particles in some cases may be less effective in controlling for $PM_{2.5}$. 72 *Fed. Reg.* 20,586, 20,617 (April 25, 2007). Petitioners made this specific point in noting that finer material is not as efficiently removed by baghouse as larger particles. Petition 2 at 40. As a further example, the particles that make up $PM_{2.5}$ may be transported over long distances while coarse particles normally travel only short distances. 70 *Fed. Reg.* 65,984, 65,997-98 (November 1, 2005). Under the principles in the case law, any person seeking to use the PM_{10} Surrogate Policy properly would need to consider these differences between PM_{10} and $PM_{2.5}$ and demonstrate that PM_{10} is nonetheless an adequate surrogate for $PM_{2.5}$.

Finally, the PM_{10} Surrogate Policy contains limits. As stated in the 1997 Seitz Memorandum, the PM_{10} Surrogate Policy provided that, in view of significant technical difficulties that existed in 1997, EPA believed that PM_{10} may properly be used as a surrogate for $PM_{2.5}$ in meeting NSR requirements "until these difficulties are resolved." Seitz Memorandum at 1. In their petition, Petitioners presented their explanation for why these technical difficulties have been resolved. Petition 2 at 45. While Petitioner may have overstated this point, subsequent to the filing of the Petition, EPA noted in the May 2008 $PM_{2.5}$ NSR Implementation Rule that "these difficulties have largely been resolved." 73 *Fed. Reg.* at 28,340/2-3.

In this case, the record for the LG&E permit does not provide an adequate rationale to support the use of PM_{10} as a surrogate for $PM_{2.5}$ under the circumstances for this specific permit. Overall, the record does not show how the use of the PM_{10} Surrogate Policy is consistent with the case law discussed above in light of the differences between PM_{10} and $PM_{2.5}$, and does not demonstrate that the use of the Policy here falls within the limits of the Policy. For these reasons and based on the record now before EPA, the Petition is granted on the claim that the permit record does not support the use of PM_{10} as a surrogate for $PM_{2.5}$.[38]

Going forward and without suggesting that the following two steps are necessary or sufficient to demonstrate that PM_{10} is a reasonable surrogate for $PM_{2.5}$, we offer the following as a possible approach to making that demonstration:

First, the source or the permitting authority establishes in the permit record a strong statistical relationship between PM_{10} and $PM_{2.5}$ emissions from the proposed unit, both with and without the proposed control technology in operation. Without a strong correlation, there can be little confidence that the statutory requirements will be met for $PM_{2.5}$ using the controls selected through a PM_{10} NSR analysis. A strong statistical relationship could be established in a variety of ways. In the case where the unit in question is a new unit, the applicant could rely on emissions data from similar units at the facility or at other facilities to develop a correlation that demonstrates the relationship between the two species. In the alternative, if actual emissions test data are not available for a similar unit, the applicant may be able to access and analyze the underlying source test data that has been used to develop emission factors for sources of the same type (including the type of control equipment). In developing such correlation, a simple ratio of AP-42 emissions factors or of the results of a single compliance stack test would not appear to be sufficient. Instead, reasonable consideration would be given to whether and how the $PM_{2.5}$:PM_{10} ratio may vary with source operating conditions, including variations in the fuel rate and in control equipment condition and operation. This consideration may be based on engineering analysis of the facility including the proposed control technology and/or review of existing or new emissions test data across a range of conditions at existing sources that are similar in design to the proposed unit.

Second, the source or the permitting authority demonstrates that the degree of control of $PM_{2.5}$ by the control technology selected in the PM_{10} BACT analysis will be at least as effective as the technology that would have been selected if a BACT analysis specific to $PM_{2.5}$ emissions had been conducted. We present here two possible paths to accomplish this. The first would be to perform a $PM_{2.5}$-specific BACT analysis, in which case the requirement is met if the control technology selected through the PM_{10} BACT analysis is physically the same as what is selected through the $PM_{2.5}$ BACT analysis, in all respects that may affect control efficiency for $PM_{2.5}$. The second path would be to perform a $PM_{2.5}$-specific BACT analysis, and show that while the type and/or physical design of the control technology may be different, the efficiency for $PM_{2.5}$ control of the technology selected through the PM_{10} BACT analysis is equal to or better than the efficiency of the technology selected through the $PM_{2.5}$ BACT analysis, across the range of operating conditions that can be anticipated for the source and the control equipment. This

[38] In 2007, EPA denied a petition requesting that EPA object to the title V permit for Spurlock for failure to include a BACT limit for $PM_{2.5}$ emissions. *In re East Kentucky Power Cooperative*, Petition No. IV-2006-4 at 41-42 (Order on Petition) (August 30, 2007). EPA found that, under the circumstances presented in that matter, KDAQ's use of PM_{10} as a surrogate for $PM_{2.5}$ was appropriate. *Id.* EPA's decision in the present Order reflects the circumstances presented in this LG&E matter, including a more comprehensive petition, and an evolving understanding of the technical and legal issues associated with the use of the PM_{10} Surrogate Policy.

demonstration may be based on engineering review and/or old or new emissions test data from units and control equipment similar to the proposed unit with the proposed control equipment.

Again, these two steps are not intended to be the exclusive list of possible demonstrations that a source or permitting authority would make to show that PM_{10} is a reasonable surrogate for $PM_{2.5}$. Sources and permitting authorities are encouraged to carefully consider the case law and the limits of the Surrogate Policy to determine what information and analysis would need to be included in the permit application and record before relying on the Surrogate Policy.

9. Petitioners' Claims Regarding Units Used for Expressing Emission Limits

(Section VII Petition 2; also addressing where raised in Petition 1 – Pb, SAM, and VOC)

Petitioners' Claims. Petitioners claim that the permit must establish enforceable emission rates in both units of mass per unit time as well as mass per mmBTU in order to demonstrate continuous compliance. Petition 2 at 46. In Petition 1, Petitioners raised this generally with regard to the enforceability of the limits set for lead, SAM, and VOC. Petition 1 at 32, 34, and 35. In Petition 2, Petitioners provide additional discussion in support of their claims regarding the units used for articulating the emission limits. In addition, in Petition 2, Petitioners state their position that hourly rates should have been set for PM and VOC (which references CO because CO is the surrogate for VOC).

EPA's Response. Kentucky's SIP-approved regulations define "emission standard," as "the numerical expression of quantity per unit of time or other parameter that limits the amount of a regulated air pollutant that a source or emission unit is allowed to emit to the ambient air." 401 KAR 52:001 § 1(30). The lbs/mmBTU standard is a limit on the amount of a pollutant that may enter the environment. While a pounds per hour or tons per year limit, as urged by Petitioners, would be a "quantity per unit of time" consistent with Kentucky's SIP-approved regulations, Kentucky's rules also allow units to be expressed in lbs/mmBTU by authorizing use of an "other parameter that limits the amount of a regulated pollutant." 401 KAR 52:001 § 1(30).

With regard to the SAM emissions limit for Unit 31, the permit establishes a pounds per hour emission rate of 26.6 based on a three hour rolling average for Unit 31. Permit Revision 3 at 29 (Section B.2(j)). The pounds per hour unit is a mass per unit time rate, and is thus consistent with Kentucky's SIP-approved regulations.

With regard to the other pollutants, Petitioners have failed to demonstrate that the permit is inconsistent with a requirement under the Act. While Petitioners recognize that the lbs/mmBTU limit can be converted into a pounds per hour limit through a calculation (Petition 1 at 33), Petitioners raise concerns that this calculation involves the use of additional information, such as heat input, which is not directly regulated by the permit. Petition 2 at 46. However, this does not impact the ability to calculate a pounds per hour rate should one be desired – heat input data is generally available from these types of facilities.[39] In support of their position, Petitioners cite to a Region 9 title V permit guidance (Petition 2 at 46),[40] which Petitioners quote as stating, "[t]he title V permit must clearly include each limit and associated information from the underlying applicable requirement that defines the limit." Petition 2 at 46. While Petitioners may prefer a pounds per hour limit, the lbs/mmBTU standard is consistent with applicable requirements and provides the required information. Petitioners also cite to EPA Region 4's comments (reprinted in relevant part in KDAQ RTC Revision 2 at 6). In those comments, Region 4 recommended that limits be expressed in pounds per hour, but did not indicate that such representation was required. EPA believes that pounds per hour emission limits present additional benefits for enforcement purposes, and thus, EPA recommends that permitting authorities utilize those types of limits. However, the applicable requirements for the LG&E facility do not require that such a limit be established, and Petitioners have not demonstrated such limits are necessary to assure compliance. For these reasons, Petitioners have failed to demonstrate that the permit is inconsistent with a requirement under the Act.

For the reasons discussed above, the Petitions are denied as to the above issues.

10. Petitioners' Claims Regarding BACT and Clean Fuels (Section VIII Petition 2)

Petitioners' Claims. In Petition 2, Petitioners argue that the BACT analyses for SAM and PM failed to consider the use of "clean" fuels – such as low sulfur coal for Unit 31. Petition 2 at 48-49. Petitioners explain that LG&E identified emissions differences associated with different coal blends, and none were eliminated as technically infeasible. Petitioners thus conclude that BACT for SAM and PM must include the consideration of low-sulfur coal and/or use of a coal-specific blend. *Id.*

EPA's Response. As was explained earlier, the BACT analysis requires the consideration of fuel alternatives where the source's design is not implicated, and where such fuels have a reasonable expectation to result in lower emissions of the pollutants at issue. *See, e.g., In re East Kentucky Power Cooperative*, Petition No. IV-2006-4 (Order on Petition) (August 30, 2007). Petitioners rely on the *East Kentucky* Petition Order to support their claims for the LG&E facility. In the *East Kentucky* matter, the issue of low-sulfur coal was raised because the facility was subject to PSD review for SO_2, which is not the case with LG&E. There is no indication in the record (or in any information provided by Petitioners) that low-sulfur coal would impact SAM and PM emissions. Moreover, LG&E does discuss low-sulfur coal in its PM BACT

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[39] Petitioners cite to the *East Kentucky Power Cooperative* title V petition order for support of the idea that a heat input limit is required in the LG&E permit. Petition 2 at 47. The *East Kentucky* matter, however, involved a permitting issue where the heat input limit was initially in the permit (as a requirement), and subsequently removed, thus resulting in EPA requiring it to be 'returned' to its place in the permit. No similar situation exists here.

[40] As an initial matter, we note that the Region 9 guidance is simply guidance and does not establish a binding requirement. In any event, it provides no support for Petitioners' contention because it does not speak to the specific issue raised by Petitioners – that these limits should be expressed in pounds per hour.

analysis, and Petitioners do not demonstrate any deficiencies with that discussion. 2004 Application at I-15-I-16.

Further, LG&E did include specific information about coal blends as part of its 2004 Application. 2004 Application at Appendix I (coal blends are discussed for the pollutants identified by Petitioners – PM and SAM). For PM/PM_{10}, LG&E included coal blends as part of its BACT analysis. *Id.* at Appendix I-14. LG&E evaluated other facilities' PM/PM_{10} rates and coal blends, as well as pointing out differences between the LG&E project and the facilities identified in the application. The PM/PM_{10} BACT analysis then evaluated different coal related options including low-sulfur coal and coal washing, and ultimately concluded that none of the different coal options was likely to result in lower PM/PM_{10} emissions. *Id.* at Appendix I-16. Thus, contrary to Petitioners' claims, LG&E did consider different coal options, but they were subsequently eliminated through the BACT process for PM/PM_{10}. With regard to SAM, the BACT analysis does not include as detailed a coal discussion as the PM BACT analysis. *Id.* at Appendix I-27-29. In that analysis, LG&E concludes that, "[e]ffective controls for H_2SO_4 include only post-combustion controls." *Id.* at I-28. Petitioners provide no information demonstrating why this conclusion is incorrect. Further, while Petitioners generally raise the SAM BACT analysis as a concern, Petitioners' claims regarding SAM appear more related to PM BACT (i.e., that sulfur levels are related to the formation of the condensable fraction of total PM) than to the SAM BACT analysis. Petition 2 at 48; *Id.* Accordingly, Petitioners provide no information demonstrating that further consideration of coal blends as part of the SAM BACT analysis is required.

For additional support of their claims, Petitioners cite to their Exhibit 15 (attached to Petition 2), a document provided to Petitioners as part of the administrative appeal on the permit. Exhibit 15 is a document produced by LG&E that includes performance guarantee information from various companies/vendors that relate to the anticipated performance of the air pollution control train for Unit 31, as described in the application. *See* Petition 2 Exhibit 15 (Cover Letter). There is nothing that indicates that this document was a part of the permit record before KDAQ at the time of Revision 2 or 3, or that it was ever provided to KDAQ. These documents are internal LG&E engineering documents regarding the construction of modifications at LG&E Trimble which Petitioners obtained as part of the permit appeal process. Petitioners interpret Exhibit 15 as demonstrating that Coal Type B has the lowest sulfur content, and in conjunction with a wet ESP, would result in lower emissions of SAM than the performance coal or Test Coal A. Petition 2 at 28; Petition 2 Exhibit 15 at 0021862. LG&E's BACT analysis for SAM explains the basis for choosing good combustion controls, a wet ESP, and a WFGD as the controls necessary to achieve the SAM limit. 2004 Application at Appendix I-29. LG&E explains that this suite of controls has additional benefits of reducing PM/PM_{10} and mercury, as well as SAM. Further, the BACT analyses did consider coal blends (even though they were not a part of the application). Exhibit 15 does not demonstrate that a particular coal blend <u>is</u> reasonably likely to lead to significant additional emission reductions for either PM or SAM, instead focusing on the suggestion that coal blends <u>may</u> result in lower SAM emissions. Further, Petitioners fail to explain why LG&E's rejection of coal blends was inconsistent with the applicable requirements, and thus have failed to demonstrate that the permit is not consistent with applicable requirements.

For the reasons discussed above, the Petitions are denied as to the above issues.

C. Petitioners' Claims Regarding Enforceability of Permit Terms and Compliance Assurance Monitoring

(Section III.A and B of Petition 1)

In Section III of the Petition, Petitioners raise various concerns associated with the enforceability of specific permit terms. Petition 1 at Section III (beginning on page 28). In Order 1, EPA responded to the vast majority of the issues raised in this section, with the exception of issues pertaining to PM/PM_{10}, mercury, and SAM because these matters were either affected by Revision 3 or Petitioners raised additional issues in Petition 2. In some circumstances, the nature of EPA's response in Order 1 did cover an issue regarding PM/PM_{10}, mercury, or SAM as raised in Section III of Petition 1. In this Order, EPA is responding to any remaining issues raised in Section III that were not addressed in Order 1.

1. Petitioners' Claims that the Permit Fails to Include Compliance Provisions Contained in the SOB and CAM Provisions are not Enforceable

(Section III.A, B, E, F, G. of Petition 1)

Petitioners' Claims. Petitioners allege that the permit fails to incorporate compliance limitations and testing parameters specified in the SOB for PM/PM_{10}, SAM, and mercury. Specifically, Petitioners take issue with the fact that Table 5.4 in the SOB (KDAQ SOB Revision 2 at 26-27) is not included in the permit. Petition 1 at 28-29.[41] Petitioners also state that the permit contains SAM monitoring, but includes it in Section B.4.j. in Table 1 and appear concerned that this is not sufficient to establish an enforceable requirement. Petition 1 at 29.

EPA's Response.

a. SOB Concern

Pursuant to federal regulations at 40 CFR § 70.7(a)(5), a permitting authority is required to provide "a statement that sets forth the legal and factual basis for the draft permit conditions (including references to the applicable statutory or regulatory provisions)." This document, referred to as the statement of basis or "SOB," must be sent to EPA in support of the "proposed permit" and to any other person who requests it. The SOB must also be included as part of the permit record. However, the SOB is not a part of the permit even though it may provide background information, including the rationale for specific permit conditions or background on the permitting authority's interpretation of an element in the permit.

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[41] Petitioners do not specify the unit to which this comment applies, instead referring to "PC boiler" which could be either Unit 1 or 31. Because the Permit at issue involves construction of a new PC boiler (Unit 31) and does not purport to modify or establish new emission limits for Unit 1, EPA interprets the comment as applying to new Unit 31.

With regard to Petitioners' specific claims that Table 5.4 of the SOB is not included in the permit, we note that the permit conditions for each emissions unit list the applicable requirements for PM/PM_{10}, SAM, and mercury, including testing requirements. The permit incorporates the applicable emission limitations and testing parameters specified in the SOB, as well as initial and periodic stack testing, and limits, for PM/PM_{10}, SAM, and mercury. *See, e.g.*, Revision 3 at 27-36 and 59-60 (Section D, "Source Emission Limitations and Testing Requirements"). For Unit 31, in addition to "Table 1: CAM Monitoring Approach" (Permit Revision 3 at 32), Parts 5-7 of Section B describe in detail the various recordkeeping, reporting, and monitoring requirements. Revision 3 at 32-36. Table 5.4 (Revision 2 SOB) only provides citations to applicable regulations and summarizes the requirements of those cited regulations. In contrast, the permit includes all the information from Table 5.4, albeit in a narrative form that is broken down by specific unit. There is no requirement that the SOB be incorporated by reference or otherwise included in a permit; nor is there a requirement that the permit contain a summary table (similar to Table 5.4) of the applicable requirements. The permit at issue is much more specific than the SOB. Petitioners have not identified a specific parameter included in Table 5.4 that is not included in the permit.

We also note that the same concern raised in the Petition to EPA was raised by Petitioners to KDAQ during the Commonwealth's public comment period. While KDAQ did not fully agree with all of the concerns raised by Petitioners, KDAQ made changes to the permit in response to Petitioners' comments. *See* KDAQ RTC Revision 2 at 27-28 (explaining that annual performance testing for VOC and lead were added to the permit). Petitioners do not explain why the changes made by KDAQ do not address the concerns they raised to the Commonwealth. In the Petition, Petitioners simply restate the same claims raised to the Commonwealth and fail to explain why KDAQ's response and subsequent changes were insufficient to address their concerns. The permit contains specific limits and associated testing requirements for PM/PM_{10}, SAM, and mercury and Petitioners do not specify how the included terms are inadequate.[42]

For the above reasons, the Petitions are denied as to the issues raised above.

General Background on CAM

On October 22, 1997, EPA promulgated final rule revisions to implement CAM for major stationary sources under title V, consistent with the CAA, as amended in 1990. 62 *Fed. Reg.* 54,900. This rulemaking resulted in changes to federal regulations found at 40 CFR part 64. These rules were intended to be implemented through the title V major source operating permit program. 62 *Fed. Reg.* at 54,901. One purpose of the rules is to ensure that permits provide a reasonable assurance of compliance with applicable requirements under the CAA where the underlying standard does not do so on its own. *Id.* at 54,900. The CAM rule specifically

[42] Petitioners also note the differences in emission limits between Units 1 and 31. This is due primarily to the fact that PSD review occurred for Unit 1 in approximately 1978. Thus, even though Unit 1 is a PC boiler, emission limitations and control technology on Unit 1 will not be the same as the new Unit 31. This difference is primarily due to technological changes from 1978 to present as well as federal and Kentucky rule changes.

exempts from coverage NSPS and National Emission Standards for Hazardous Air Pollutants proposed after the CAA was amended in 1990 (i.e., after November 15, 1990), as well as units subject to CAA acid rain program requirements. *See* 62 *Fed. Reg.* at 54,904 (codified at 40 CFR § 64.2(b) ("Exemptions")). Additionally, the CAM rule applies only to a pollutant-specific emissions unit (PSEU), which is defined as a unit that: (1) is subject to an emission limitation or standard[43] for the applicable regulated air pollutant (or a surrogate thereof); (2) uses a control device to achieve compliance with any such emission limitation or standard; and (3) has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source. 40 CFR § 64.2(a).

For PSEUs to which CAM applies, the owner/operator must develop monitoring that meets specified criteria for selecting appropriate indicators of control performance, establishing ranges for those indicators, and for responding to any excursions from those ranges. 40 CFR § 64.3; 62 *Fed. Reg.* at 54,902. The CAM rule also establishes numerous recordkeeping and reporting requirements to ensure compliance. 40 CFR §§ 64.4, 64.9. The analysis of whether CAM applies at a particular unit is done on a pollutant-by-pollutant basis such that CAM may apply for certain pollutants at a unit but not for others. 62 *Fed. Reg.* at 54,922. The concept of the CAM approach is that compliance with an emission standard is assured through requiring monitoring of the operation and maintenance of the control equipment and, if applicable, operating conditions of the PSEU. 62 *Fed. Reg.* at 54,918. The CAM analysis is that "[o]nce an owner or operator has shown that the installed control equipment can comply with an emission limit, there will be a reasonable assurance of ongoing compliance with the emission limit as long as the emissions unit is operated under the conditions anticipated and the control equipment is operated and maintained properly." *Id.* More specific information regarding the CAM rule can be found in the preamble to the October 1997 rulemaking, the rules themselves (40 CFR part 64), and in the CAM Technical Guidance Document (August 1998), available on the EPA Web site.

With regard to indicator parameters and the correlation between pollutants, the preamble to the CAM rule provides:

> The CAM approach builds on the premise that if an emissions unit is proven to be capable of achieving compliance as documented by a compliance or performance

[43] For CAM purposes, the term "emission limitation or standard" is defined as:

> any applicable requirement that constitutes an emission limitation, emission standard, standard of performance or means of emission limitation as defined under the Act. An emission limitation or standard may be expressed in terms of the pollutant, expressed either as a specific quantity, rate or concentration of emissions...or as the relationship of uncontrolled to controlled emissions...An emission limitation or standard may also be expressed either as a work practice, process or control device parameter, or other form of specific design, equipment, operational, or operation and maintenance requirement.

40 CFR § 64.1.

> test and is thereafter operated under the conditions anticipated and if the control equipment is properly operated and maintained, then there will be a reasonable assurance that the emissions unit will remain in compliance. In most cases, this relationship can be shown to exist through results from the performance testing without additional site-specific correlation of operational indicators with actual emission values.

62 *Fed. Reg.* at 54,926. The preamble to the CAM rule further provides that:

> The presumptive approach for establishing indicator ranges in part 64 is to establish the ranges in the context of performance testing. To assure that conditions represented by performance testing are also generally representative of anticipated operating conditions, a performance test should be conducted under conditions specified by the applicable rule or, if not specified, generally under conditions representative of maximum emission potential under anticipated operating conditions. In addition, the rule allows for adjusting the baseline values recorded during a performance test to account for the inappropriateness of requiring that indicator conditions stay exactly the same as during a test. The use of operational data collected during performance testing is a key element in establishing indicator ranges; however, other relevant information in establishing indicator ranges would be engineering assessments, historical data and vendor data. Indicator ranges do not need to be correlated across the whole range of potential emissions.

62 *Fed. Reg.* at 54,927. In addition, EPA has explained that established CAM parameters are not enforceable limits. The CAM rule preamble addressed this by pointing out that:

> The obligation to correct excursions as expeditiously as practicable is the enforceable component associated with establishing an indicator range under part 64. Part 64 does not establish that an excursion from an indicator range constitutes an independent violation by itself.

Id. at 54,931; *see also Id.* at 54,928. Thus, CAM provides a reasonable assurance of compliance with emission limits and consequently, the adoption of CAM as "enhanced monitoring" meets the requirement of the CAA but does not convert the CAM parameters to enforceable permit limits.

With regard to the LG&E facility, KDAQ determined that CAM requirements applied to SAM and fluorides at Unit 31. KDAQ SOB Revision 2 at 12-13. Specifically KDAQ explained,

> Pre-control emissions of SO_2, NO_x, PM/PM_{10}, [SAM] and fluorides are each greater than 100 tpy. CAM requirements under 40 CFR 64.2(b) will be met for SO_2, NO_x, and PM/PM_{10}, by compliance with the Acid Rain program and compliance with a post-November 15, 1990 NSPS standard. In accordance with Part 64, LG&E has submitted additional information on its CAM plan for [SAM]

and fluorides. Pursuant to 401 KAR 52:020, the plan will receive public notice to ensure federal enforceability.

KDAQ SOB Revision 2 at 13. This is consistent with the requirements of 40 CFR § 64.2(b) which exempts units from CAM that are regulated by the CAA acid rain program or by a post-November 15, 1990 NSPS. The terms of the CAM Plan for SAM and fluorides are discussed in the SOB (Table 4.1 on page 13) and are also included in Revision 3 at page 32.

b. CAM Issue in Section III.B. of Petition 1

Petitioners raise the issue that CAM should also be required for other pollutants such as lead and total PM/PM_{10}. Petition 1 at 30. The only support for this statement is a parenthetical "the CEMS [continuous emissions monitoring system] only measures filterable" (Petition 1 at 30), which appears to apply specifically to PM/PM_{10} and not lead. As was noted earlier, CAM requirements do not apply where Acid Rain program requirements apply. 40 CFR § 64.2(b)(1)(iii). KDAQ explained in the SOB for Revision to that "CAM requirements under 40 CFR § 64.2(b) will be met for SO_2, NO_x, and PM/PM_{10}, by compliance with the Acid Rain program and compliance with a post-November 15, 1990 NSPS." KDAQ SOB Revision 2 at 13. There are a number of compliance provisions in the permit for PM/PM_{10}. These are discussed in greater detail below, in response to Petitioners' concerns regarding the enforceability of the PM/PM_{10} limits. Furthermore, the permit requires CEMS, which provides for continuous measurement of emissions and thus provides a reasonable assurance of compliance. KDAQ SOB Revision 2 at 28. KDAQ also explained that it made some changes to the permit per Petitioners' comments (adding PM/PM_{10} testing requirements to the permit), and that KDAQ approved an alternative method for compliance with PM/PM_{10}. KDAQ RTC Revision 2 at 33. Petitioners have failed to demonstrate that the permit does not comply with a requirement under the Act, and thus, the Petitions are denied for the reasons discussed above, and those enumerated below with regard to PM/PM_{10}.

EPA addressed the majority of the lead issues raised in Order 1 at 20-21. With regard to Petitioners' contention that a CAM plan was required for lead, KDAQ explained that Unit 31 is not a PSEU for lead. KDAQ RTC Revision 2 at 29. Petitioners provide no information demonstrating that KDAQ erred in reaching this conclusion. Thus, Petition 1 is denied with respect to lead because Petitioners have failed to demonstrate that the permit is not out of compliance with a requirement under the Act.

2. Petitioners' Claims that CAM Compliance Provisions for SAM are not Adequate to Ensure Compliance with Permit Limits
(Section III.E. of Petition 1)

Petitioners' Claims. Petitioners raise four issues associated with their claim that the SAM limit in the permit is not enforceable: (1) that the limit should be expressed in mass per unit time instead of firing rates; (2) that a 30-day rolling average cannot be determined from a 3-hour stack test; (3) that CAM cannot be used to assure compliance with BACT limits such as this one; and (4) SO_2 is not a good indicator of SAM because they are related in a complex, non-linear way. Petition 1 at 34-35.

EPA's Response. With regard to the first issue about the units for the SAM emissions limit, contrary to Petitioners' claim, the permit establishes an emission rate of 26.6 pounds per hour (lbs/hr) based on a three hour rolling average for Unit 31. Permit Revision 3 at 29 (Section B.2(j)). The pounds per hour units are a mass per unit time rate. The same rate and units were also included in Permit Revision 2. For a broader discussion of Petitioners' concerns regarding how emissions are measured, we refer to our response in section 9, above.

With regard to the remaining issues, the permit establishes a 26.6 lbs/hr limit based on a three hour rolling average. Permit Revision 3 at 29 (Section B.2(j)). Further, in response to comments by Petitioners and EPA, KDAQ did make some changes to the permit to clarify the monitoring/compliance provisions. *See* KDAQ RTC Revision 2 at 7, 32. The permit also establishes a CAM approach to provide a reasonable assurance of compliance. Permit Revision 3 at 32. The CAM approach includes the emission limit, an association with the SO_2 CEMS, initial testing to establish the correlation between SAM and SO_2, continuous monitoring of SO_2, weekly coal sampling, in addition to other recordkeeping and quality assurance/quality control requirements. *Id.* The various compliance assurance mechanisms established for SAM are included in the permit. The issue of surrogate pollutants and CAM was discussed in the September 10, 2008 Order, in Part IV. B. and is relevant here (but not repeated). The SOB provides relevant background information not only to support the CAM approach, but also to support the use of SO_2 as a surrogate for SAM. *See* KDAQ SOB Revision 2 at 21-22. In the SOB, KDAQ explained the relationship between SAM and SO_2. KDAQ did not claim or suggest that the relationship is linear, but at the same time, KDAQ provided a reasoned explanation for why SO_2 is an appropriate surrogate. Specifically, the SOB states that, "sulfuric acid is present in the flue gasses generated from combustion of coal because a fraction of the [SO_2] produced is further oxidized to sulfur trioxide (SO_3). SO_3 reacts with water in flue gas to form sulfuric acid vapor [i.e., SAM]." *Id.* at 21. Petitioners provide no information suggesting that applicable requirements dictate that pollutants must be linearly related to serve as surrogates for each other.

Finally, as was discussed earlier in this Order, EPA's final CAM rule clearly allows for the use of appropriate surrogate pollutants and SO_2 is routinely used across the United States as a surrogate for demonstrating compliance with SAM. The applicability section of the CAM rule explains that part 64 applies "to a pollutant-specific emissions unit at a major source...if the unit satisfies all of the following criteria," including that the "unit is subject to an emission limitation or standard for the applicable regulated air pollutant (<u>or a surrogate thereof</u>)..." 40 CFR § 64.2(a)(1)(*emphasis added*). EPA's preamble to the CAM rule further explains the use of surrogate pollutants as follows:

> The Agency also notes that the applicability provisions in part 64 include a "surrogate" of a regulated air pollutant to address situations in which the emission limitation or standard is expressed in terms of a pollutant (or other surrogate) that is different from the regulated air pollutant that is being controlled.

62 *Fed. Reg.* at 54,912. Further, CAM can apply to any limit in a permit. There is nothing in the CAM rule (including 40 CFR § 64.2, "Applicability") that prevents CAM from applying to a BACT limit, or the SAM limit to which it is applied in the LG&E permit. Petitioners fail to

explain that KDAQ's analysis was inconsistent with applicable requirements, or unreasonable considering the options available (i.e., no continuous emissions monitors specifically for SAM). For these reasons, the Petitions are denied as to these issues.

3. ***Petitioners' Claims that the Unit 31 Mercury Limit is not Enforceable*** (Section III.F of Petition 1)

Petitioners' Claims. Petitioners allege that the mercury limit set for Unit 31 is not enforceable because (1) the permit does not indicate whether the megawatt hours are gross or net; and (2) the averaging time is ambiguous and excessively long. Petition at 35.

EPA's Response. The permit sets a limit for mercury at 13 x 10^{-6} lbs/megawatt (MW) hour (Gross output) based on a 12-month rolling average. Permit Revision 3 at 29 (Section B.1.). The permit further notes that this limit ensures compliance with the CAA Section 111 New Source Performance Standard (NSPS) found at 40 CFR § 60.45Da. With regard to the issue of whether the megawatt hours are gross or net, KDAQ revised the permit in light of Petitioners' concerns and clarified that the megawatt hours are in fact gross output. KDAQ RTC Revision 2 at 32; Permit Revision 3 at 29 (Section B.2.l). With regard to the averaging time, the applicable requirement (40 CFR § 60.45Da) establishes a 12-month rolling average as the acceptable averaging time. This is the averaging time included in the permit. A CEMS will be installed for mercury – to ensure compliance with the established emission limits. Permit Revision 3 at 29 (Section B.4(a)). The averaging times are clearly established in the permit, as is the compliance mechanism, and inspectors will have access to the CEMS data and be able to assure compliance. KDAQ also explained this point in its response to comments. KDAQ RTC Revision 2 at 32. Although Petitioner's claims regarding the enforceability of the mercury limit are not supported, we note that the limit is based on the NSPS for mercury that was vacated by the court in *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008), *cert. denied*, 77 U.S.L.W. 3148 (U.S. Feb. 23, 2009) (vacating Clean Air Mercury Rule). Because that rule was vacated by the Court, and as provided in section D, below, of this Order, we have objected to the current revision to the permit (Revision 4) on the basis that Kentucky is required to perform a case-by-case Section 112(g) analysis for mercury and other hazardous air pollutants. Because Kentucky is required to consider mercury limits pursuant to the Section 112(g) analysis, Petitioners' claims are moot.

4. ***Petitioners' Claims that the PM/PM_{10} Limits are not Enforceable*** (Section III.H of Petition 1)

Background Information on Particulate Matter and CEMS

Particulate matter (PM and PM_{10}) emitted from a coal-fired boiler typically includes both "filterable" and "condensable" PM.[44] Filterable PM is directly emitted from a stack or other device, and it can be a solid or liquid. This type of PM can be "caught" on a filter and controlled by, for example, the PJFF included in the permit for LG&E. Condensable PM is formed within the boiler exhaust gas flow as the result of reactions, cooling, and dilution. This PM can be

[44] The PM/PM10 BACT discussion earlier in this Order also provides some relevant background information relating to the enforceability of the PM/PM10 emission limits.

liquid or solid, but tends to have a diameter of less than 10 micrometers (therefore, within the PM_{10} size range). Controls for condensable PM emissions include those included in the LG&E permit: lime injection, WFGD, and WESP. EPA has established different reference test methods for evaluating emissions of filterable and condensable PM. The standard reference method for measuring filterable PM is EPA Method 5, described in 40 CFR Part 60, Appendix A. This method is suitable for most industrial sources, and provides a measure of the total amount of filterable solid particulate matter emitted from a stack at the source. EPA Methods 201/201A, described in 40 CFR Part 51, Appendix M, are another common method for measuring filterable PM_{10}. These methods use an in-stack cyclone that separates the PM_{10} from the total PM. If condensable PM_{10} emissions are also an issue, then EPA Method 202, or an approved variation can be applied. *See* 40 CFR Part 51, Appendix M (describing Method 202).

A continuous emission monitoring system or CEMS is the total equipment necessary for the determination of a gas or particulate matter concentration or emission rate using pollutant analyzer measurements and a conversion equation, graph, or computer program to produce results in units of the applicable emission limitation or standard. Performance Specifications are used for evaluating the acceptability of the CEMS at the time of or soon after installation and whenever specified in the regulations. Quality assurance procedures in federal rules (and Kentucky's rules) are used to further ensure the effectiveness of quality control (QC) and quality assurance (QA) procedures and the quality of data produced by any CEMS that is used for determining compliance with the emission standards on a continuous basis as specified in the applicable regulation. In summary, the purpose of PM CEMS is to quantify PM emissions as accurately and precisely as possible to ensure compliance with the applicable PM emission limits. *See, e.g.*, 69 *Fed. Reg.* 1,786, 1,789 (PS-11 Final Action).

To meet the objectives of the PM CEMS, EPA described performance specification (PS)-11 for PM/PM_{10}. Rules regarding the use of PS-11 and PM CEMS were first published in the *Federal Register* on April 19, 1996, as part of the proposed Hazardous Waste Combustion Maximum Available Control Technology standard. PS-11 was published again on December 30, 1997, for public comment on revisions made to these procedures. On January 12, 2004, EPA published a final rule regarding PS-11 and PM CEMS (69 *Fed. Reg.* 1,786). PS-11 and associated QA/QC procedures ensure that PM CEMS are properly installed, operated, and maintained. The final PS-11 rules describe installation, operation, and maintenance procedures. EPA has also published guidance on the selection and use of PM CEMS in the PM CEMS Knowledge Document (available at: http://www.epa.gov/ttn/emc/cem/pmcemsknowfinalrep.pdf) which may be revised periodically to incorporate additional guidance, example calculations, and other information that assists with understanding and complying with PS-11 applicable QA/QC procedures.

PM Limits in the LG&E Permit

Permit Revision 3 includes two separate particulate limits for Unit 31 (both of which were also included in Permit Revision 2). Permit Revision 3 at 28 (Section B.2(a) and (b)). The first limit is specific to PM_{10}, and sets a limit whereby the unit may not exceed 0.018 lb/mmBTU (for filterable and condensable) of heat input based on the average of three one-hour tests. *Id.* Compliance with this limit is determined by a CEMS and specifics regarding reporting and maintaining CEMS data are included in the permit. *Id.* at 32-36, 59. As is described in the SOB, there are two primary control devices necessary for Unit 31 to comply with this PM_{10} limit – a pulse jet fabric filter (PJFF) and a wet electrostatic precipitator (WESP). KDAQ SOB Revision 2 at 18-20. As explained by KDAQ, a PJFF is a type of baghouse that uses fabric bags as filters to collect filterable particulates. *Id.* at 18. The WESP is another type of particulate control whereby particulates are removed by charging fly ash particles. ESPs can be wet or dry; the LG&E facility initially was permitted with just a wet ESP but added a dry ESP as part of Revision 3. KDAQ SOB Revision 3 at 12. In the SOB for Revision 2, KDAQ evaluated the different options and determined that a WESP represented a control sufficient for LG&E Unit 31 to meet the condensable PM_{10} limit. KDAQ SOB at 19-20. The PM_{10} limit described above is consistent with Kentucky rules at 401 KAR 59:016 §§ 3 and 6.

In addition to the above-described PM_{10} limit, the permit also imposes a PM/PM_{10} limit specific to filterable particulate emissions that is consistent with federal new source performance standards (NSPS) found at 40 CFR § 60.42a(c). Permit Revision 3 at 28 (Section B.2(b)). The permit further requires that compliance with the PM/PM_{10} limit be demonstrated by data provided from the PM CEMS. Where the PM CEMS is not sufficient to demonstrate compliance with the applicable limit (i.e., for condensable PM), LG&E is required to use an applicable reference method. Permit Revision 3 at 59 (Section D.4). In summary, the permit sets a limit for both filterable and condensable PM/PM_{10}, and requires that compliance be demonstrated through use of the PM CEMS and, where CEMS are not sufficient, through applicable reference methods, which includes EPA Method 202 for condensable PM emissions. As a result, Petitioners failed to demonstrate a flaw in the permit.

Petitioners' Claims. Petitioners allege that the PM/PM_{10} limits in the permit are not enforceable for the following reasons: (1) the PM CEMS is not a sufficient monitoring system to ensure "continuous" compliance because it only measures the filterable fraction of PM/PM_{10}; annual stack tests are also not sufficient to ensure compliance; (2) the limit is not expressed in units of mass per unit time; (3) for Unit 1, the concern that opacity is an indicator for PM/PM_{10}; (4) for Unit 31, the limit for PM/PM_{10} is a "sum of filterable and condensable" particles but the permit does not include any monitoring to determine compliance with the limit; (5) permit sets a drift rate from the cooling tower but has no supporting monitoring to demonstrate compliance because the limit does not specify testing frequency, methods, or location. Petition 1 at 36-38. Except for numbers 3 and 5 above, all the issues appear to regard the new Unit 31.

EPA's Response. With regard to issues 1 and 4 above regarding the demonstration of continuous compliance for both filterable and condensable PM/PM_{10} emissions, the permit establishes use of the PM CEMS as well as applicable reference methods for determining compliance. Petitioners state that "annual stack tests for PM/PM_{10} are not adequate to assure continuous compliance," (Petition 1 at 36) but the permit requires more than an annual stack test. As was explained above, the permit establishes compliance mechanisms through the use of the PM CEMS and other applicable reference methods (which would include Method 202). Petitioners are simply incorrect in stating that "there are no U.S. EPA approved alternative methods for measuring condensable PM/PM_{10}." Method 202 is such a method, and it is required by the permit. Thus, Petitioners have not demonstrated that the permit is not in compliance with the Act.

Issue 2 above regards the units used to express the PM/PM_{10} limit. This issue is discussed previously in this Order and will not be repeated here. Additionally, we note that the Kentucky SIP-approved rules establish PM/PM_{10} limits in terms of lbs/mmBTU. *See, e.g.*, 401 KAR 59:016 § 3; *see also* 401 KAR 52:001 § 1(30). For this reason, as well as those discussed in previous sections, the PM/PM_{10} limits expressed in the LG&E permit are consistent with applicable requirements.

Issue 3 above regards Unit 1, which is the original coal-fired boiler at the facility. As was noted earlier in this Order, that unit was permitted and constructed in the late 1970s, and thus, is not necessarily required to include all the same control technology or emission limits as the new Unit 31. The BACT analysis for Unit 1 is not at issue in Revisions 2 and 3 to the permit. At the time of construction of Unit 1, and even today depending on the circumstances, opacity was an acceptable indicator for PM/PM_{10}. *See, e.g.*, 62 *Fed. Reg.* at 54,912 (CAM Rule). Further, Petitioners did not raise this issue in their comments to KDAQ, and provide no information supporting their statement about opacity and Unit 1. Petition 1 Exhibit A at 21-22. Thus, Petitioners have failed to meet the minimum procedural requirements in CAA section 505(b) for this issue, and have failed to demonstrate that the permit is not in compliance with the Act.

With regard to issue 5, the permit sets a drift elimination rate for Unit 41 – the new Linear Mechanical Draft Cooling Tower – of 0.0005% drift elimination. This is consistent with what the Petitioners identify in Petition 1 as BACT (Petition 1 at 18-22). Permit Revision 3 at 48 (Section B, Emissions Unit 41). The drift rate is related to prevention of droplet loss, which in turn, has a relationship to PM emissions at the facility. Generally, the lower the drift rate, the lower the PM emissions. The permit requires an initial performance test to verify drift percent achieved by the drift eliminator, which is to be conducted consistent with the "Cooling Technology Institute (CTI) Acceptance Test Code (ATC) # 140." *Id.* In addition to the initial performance test, there is additional monitoring of the total dissolved solids in the circulating water on a monthly basis, which is an indicator of future drift. *Id.* Sections E (Source Control Equipment Requirements) and F (Monitoring, Record Keeping, and Reporting Requirements) of the permit (Permit Revision 3 at 60-61) also apply to Unit 41. Thus, Petitioners are not correct that the permit has "no supporting monitoring." Petition at 37. KDAQ responded to Petitioners' comments regarding the drift rate by adding some additional monitoring into the permit for this issue. In their Petition, Petitioners continue to raise concerns with the level of monitoring for the drift rate, but cite to no authority to explain that the permit limits are inconsistent with applicable requirements. Petition 1 at 37-28. Nor do Petitioners explain why KDAQ's response was insufficient.

For the reasons described above, Petitioners have not demonstrated that the permit fails to comply with a requirement under the Act. As a result, Petition 1 is denied as to the issues raised regarding the PM/PM_{10} limits and enforceability.

5. Petitioners' Claims Regarding Other Conditions that are not Enforceable

(Section III.J. of Petition 1 – Bullets 5-8)

Petitioners' Claims. In Petition 1, Petitioners include a bulleted list of issues that they believe render the permit unenforceable. These include improper reliance on manufacturer specifications not included in the permit itself; permit does not identify test methods used to determine requirements for pollutants, e.g., PM/PM_{10}; emissions caps on NO_x and SO_2 are unenforceable due to permit's lack of explanation regarding how such emissions are calculated when the CEMS are not measuring NO_x and SO_2; and failure of the permit to ensure that the project's net increase in emissions of NO_x and SO_2 continue to remain below the significance levels by omitting any ongoing requirements to measure emissions of NO_x and SO_2.[45] Petition 1 at 39-41.

EPA's Response. As a general matter, conclusory allegations regarding a permit or the permitting authority are insufficient and will not raise an objectionable issue under section 505(b) of the Act because such allegations generally do not demonstrate a specific flaw in the permit. Petitioners must make some level of demonstration and provide EPA with sufficient information to understand how the permit is defective. *In the Matter of Al Turi Landfill, Inc.*, Petition No. II-2002-13-A (Order on Petition) (January 30, 2004); *see also, In the Matter of the New York Organic Fertilizer Company*, Petition No. II-2002-12 at pages 7-8 (Order on Petition) (May 24, 2002); *In the Matter of Sirmos Division of Bromante Corp.*, Petition No. II-2002-03 at page 7 (May 24, 2002). Broad generic claims "lack sufficient specificity" to satisfy these criteria and will be not be reviewed. *In re Steel Dynamics, Inc.*, 9 E.A.D. at 239-240.

With regard to the bulleted list of items on pages 39-41 of Petition 1, Petitioners cite only to CAA Section 504(a) but fail to explain how the permit is inconsistent with a requirement under the Act. Further, it is not apparent that these individual concerns were raised in comments to KDAQ, thus the procedural requirements in section 505(b) of the CAA do not appear to have been satisfied. *See* Petition 2 Exhibit A. To the extent that some of these issues are duplicative with issues raised earlier in the Petitions, we refer to the responses already provided. Below is a brief explanation of why each of the issues raised by Petitioners is denied.

With regard to their claim that the manufacturer specifications for control equipment are not included in the permit, we note that PSD permits are preconstruction permits issued prior to construction of a particular unit. As a result, the manufacturers' specifications are not necessarily available at the time the permit is issued by the permitting authority. While the permit directs the permittee to install a particular type of control technology, the permittee does not necessarily have a contract established with a specific provider at the time of permit issuance. For this reason, PSD permits typically do not include the specific manufacturers' specifications. There is no EPA-approved regulation that requires inclusion of the manufacturers' specifications into the text of the permit. The LG&E applications (2004 and 2007) do contain some manufacturers information for certain portions of the modification. *See, e.g.*, 2004 Application, Appendices C and D. Petitioners do not identify how this information should be included into the permit, or why that would be required. However, the permit does also require that final design information be provided to KDAQ and be accessible to the public. Permit Revision 3 at

[45] These issues are issues 5-8 in the referenced section of Petition 1. We responded to issues 1-4 in the previous Order dated September 10, 2008.

66 (Section G. 18). Section E of the permit (Permit Revision 3 at 60) also discusses the permittee's obligation to comply with operation and maintenance procedures. With regard to this issue, the Petitioners failed to demonstrate that the permit is not in compliance with the Act.

The issue raised regarding test methods to determine compliance for PM/PM_{10} and other pollutants were raised previously in the Petition and responded to in those sections. This Order has thus already discussed what test methods are applicable to a variety of pollutants, including PM/PM_{10}. Petitioners are simply incorrect in alleging that "the permit does not identify the test methods that would be used to determine compliance with regulated pollutants and coal quality parameters." Petition 1 at 40. In addition to Section D (Permit Revision 3 at 59), each section of the permit applicable to specific units also contains test method information. Thus, Petitioners failed to demonstrate that the permit is not in compliance with the Act.

Petitioners' claims that the emissions caps for NO_x and SO_2 are unenforceable and that the permit lacks ongoing requirements to measure those pollutants are incorrect. The permit contains numerous testing, reporting, and recordkeeping requirements for NO_x and SO_2 associated with many units, but specifically, Units 1 and 31 – the two coal-fired boilers. In addition, the permit includes specific requirements for periods when the CEMS associated with certain units are not operational. *See, e.g.*, Permit Revision 3 at 31 (Section B.2.(h) for Unit 31). As was previously discussed in the netting section, one requirement for netting is that the reductions of NO_x and SO_2 be enforceable. In this case, the reductions were taken as lower permit limits in Revision 1 (Minor Modification). *See* KDAQ SOB Revision 1 (Minor Modification). Compliance with the new NO_x and SO_2 limits is demonstrated by use of a continuous emissions monitor. *See* Permit Revision 3 at 3, "Compliance with nitrogen oxide and sulfur dioxide emissions." Thus, Petitioners failed to demonstrate that the permit is not in compliance with the Act. The issues regarding netting were also addressed in detail earlier in this Order.

For the above reasons, Petition 1 is denied as to these issues.

D. Petitioners' Claims Regarding the Maximum Achievable Control Technology Determination

Petitioners' Claims. Petitioners allege that the permit lacks a maximum achievable control technology (MACT) determination for mercury and other HAP for the Unit 31 construction. Petition 2 at 16-27. Petitioners explain their understanding of why the case-by-case MACT requirements described in CAA Section 112(g) apply to the Unit 31 construction. Petitioners also suggest that to the extent that a 112(g) determination was done, KDAQ did not follow the proper procedures for undertaking a 112(g) determination and that the analysis is procedurally and substantively flawed. In general, they claim that KDAQ misapplied the 2-step 112(g) process by failing to properly establish a MACT floor and failing to properly undertake a beyond-the-floor analysis.

EPA's Response. On June 5, 2009, EPA issued a letter objecting to the most recent permit revision for LG&E on the basis that KDAQ must undertake a Section 112(g) analysis for all hazardous air pollutants with respect to Unit 31 in order to comply with all applicable CAA requirements. *See also* 40 CFR § 70.5(a)(1)(ii). The legal basis of the objection is explained briefly in the letter, and is also summarized below. Because of EPA's objection, EPA is denying the Petition as moot on this issue.

On January 7, 2009, EPA issued a Memorandum entitled, "*Application of CAA Section 112(g) to Coal- and Oil-Fired Electric Utility Steam Generating Units that Began Actual Construction or Reconstruction Between March 29, 2005 and March 14, 2008.*" In that Memorandum, EPA explained that coal- and oil-fired electric utility steam generating units (EGU's) remain on the Section 112(c) list and therefore are subject to Section 112(g). In addition, the Memorandum addresses the applicability of Section 112(g) to EGUs that are major sources and that began actual construction or reconstruction between the March 29, 2005 promulgation of the 112(n) Revision Rule (removing EGUs from the CAA Section 112(c) list) and the March 14, 2008 vacatur of that rule, and concludes that those EGUs are required to comply with Section 112(g). LG&E began actual construction of Unit 31 between March 29, 2005 and March 14, 2008, and for that reason, EPA objected to the most recent permit revision for LG&E.

V. CONCLUSION

For the reasons set forth above, and pursuant to Section 505(b) of the CAA and 40 CFR § 70.8(d), I hereby grant in part and deny in part the issues in the Petitions submitted on March 2, 2006, and April 29, 2008, and which were not previously addressed in the Order dated September 10, 2008.

8/12/09
Dated

Lisa P. Jackson
Administrator

PRO Fact Sheet No. 103

Partner Reported Opportunities (PROs) for Reducing Methane Emissions

Install Electric Compressors

Technology/Practice Overview

Description

Gas-fired engines are often used to run compressors, generators, and pumps. In some operations, part of the produced gas stream is used to power these engines. Methane emissions result from leaks in the gas supply line to the engine, incomplete combustion, or during system upsets. The majority of the gas from a "system upset" comes from compressor blowdown emissions and is the same for both gas engine and electric motor driven compressors.

Partners reported that installing electric motors in place of gas-fired units can decrease gas losses. Electric motors reduce the chance of methane leakage by eliminating the need for fuel gas, require less maintenance, and improve operational efficiency.

Operating Requirements

An electrical power supply is needed to implement this technology.

Applicability

Remote facilities with an available electrical power source and high maintenance cost may be good candidates for this technology.

Methane Emissions

Methane emissions savings are based on an emissions factor of 2.11 Mcf per year horsepower.[1] Partners have reported methane savings ranging from 40 Mcf per year up to 16,000 Mcf per year.

- [x] Compressors/Engines
- [ ] Dehydrators
- [ ] Directed Inspection & Maintenance
- [ ] Pipelines
- [ ] Pneumatics/Controls
- [ ] Tanks
- [ ] Valves
- [ ] Wells
- [ ] Other

Applicable Sector(s)

- [x] Production
- [x] Processing
- [x] Transmission
- [ ] Distribution

Other Related Documents:

Install Electric Motor Starters, PRO No. 105

Convert Gas Driven Chemical Pumps, PRO No. 202

Economic and Environmental Benefits

Methane Savings

Estimated annual methane emission reductions	*32,800 Mcf per 5 reciprocating compressors replaced*

Economic Evaluation

Estimated Gas Price	Annual Methane Savings	Value of Annual Fuel Gas Savings*	Estimated Implementation Cost	Incremental Operating Cost	Payback (months)
$7.00/Mcf	32,800 Mcf	$11,900,000	$6,050,000	$6,200,000	13 Months
$5.00/Mcf	32,800 Mcf	$8,500,000	$6,050,000	$6,200,000	32 Months
$3.00/Mcf	32,800 Mcf	$5,100,000	$6,050,000	$6,200,000	Does not payback

** Only the value of fuel gas savings were considered, since the avoided methane emissions from the compressor are unburned hydrocarbons and, therefore, are included in the fuel gas savings.*

Additional Benefits

- Reduced fuel gas consumption
- Increased operational efficiency and reduced maintenance costs
- Faster permitting due to lower noise output and no emissions

Install Electric Compressors (Cont'd)

Economic Analysis

Basis for Costs and Emissions Savings

Methane emissions reductions of 32,800 Mcf per year apply to the replacement of two 2,650 hp, two 4,684 hp, and one 893 hp reciprocating engines.

One partner reported replacing two 2,650 hp, two 4,684 hp, and one 893 hp reciprocating compressors with four 1,750 hp electric compressors. The total cost of replacement was $6,050,000 and includes the cost of the motor and the compressor.

Fuel gas savings of 1,700,000 Mcf per year apply to the 5 compressors replaced assuming 20% efficiency, a heat content of 1,020 Btu per scf of gas, and 8,760 hours of operation per year. When estimating the value of gas savings, only the value of fuel gas savings were considered since the avoided methane emissions attributed to the compressor are unburned hydrocarbons and are therefore considered to be included in the fuel gas savings.

Incremental operating costs are primarily electricity costs. Reduced maintenance costs would offset some of the electricity costs, and are assumed to be approximately 10% of the capital costs. Assuming 50% efficiency for the four 1,750 hp electric compressors and 8,760 hours of operation per year at a price of $0.075 per kw-hr, electricity costs would be $6,800,000 per year.

Discussion

Installing an electric motor in place of a gas driven engine will increase operational efficiency, reduce maintenance costs, and yield significant methane savings. The capital costs and the electricity costs, however, are higher for an electric motor compared to those for a gas driven engine. The primary reasons for implementation of this project are fuel gas savings and maintenance savings. An additional benefit is the faster permitting process as a result of lower noise output and no emissions. It should be noted, however, that the economics may vary significantly for transmission companies as a result of contractual agreements and ownership of the gas which would be responsible for the additional revenue included in this economic analysis.

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

[1] Emission factor is based on Annex 3 of the Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990—2009. The emission factor is for Compressor Gas Engine Exhaust and is calculated as shown below:

0.24 scf/HPhr x 8,760 hrs / 1000 = 2.1 Mcf CH4/HPyr

Before The

State Of Wisconsin

DIVISION OF HEARINGS AND APPEALS

In the Matter of an Air Pollution Control Construction Permit Issued to Wisconsin Electric Power Company for the Elm Road Generating Station, Permit No. 03-RV-166, located in Oak Creek, Wisconsin	Case No.: IH-04-03

FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

Background

Wisconsin Electric Power Company ("Wisconsin Electric"), 231 West Michigan Street, Milwaukee, Wisconsin, submitted an air pollution control permit application to construct a new electric generating station that would be located on or adjacent to property at its existing Oak Creek Power Plant (OCPP) site in Milwaukee County.

The proposed new facility is identified as the Elm Road Generating Station (ERGS). The ERGS as proposed would consist of two super-critical pulverized coal (SCPC) units and a single integrated coal gasification combined cycle (IGCC) unit, which would have a collective capacity of approximately 1,830 megawatts of coal-based generating power. The two proposed SCPC units are each sized at 615 megawatts, and the IGCC unit is sized at 600 megawatts. Wisconsin Electric originally proposed to construct the SCPC units first, placing one in service in 2008 and the other in 2009. Wisconsin Electric originally proposed to construct the IGCC unit thereafter, with an original planned in service date of 2011.

On January 14, 2004, the DNR issued a construction permit authorizing Wisconsin Electric to build the ERGS as proposed, with two SCPC units and one IGCC unit.

Wisconsin Electric sought also to have the Public Service Commission of Wisconsin ("PSC") issue a Certificate of Public Convenience and Necessity ("CPCN") for the ERGS project configured with the two SCPC units and the single IGCC unit. In a decision dated November 10, 2003, the PSC approved construction of the two SCPC units, but delayed by one year the respective dates for each to be placed in service. The PSCW denied the request for a CPCN to construct the IGCC unit.

By order dated November 29, 2004, the circuit court in Dane County vacated the PSC's issuance of a CPCN and remanded the matter to the PSC for further proceedings. Appellate review of the circuit court order is presently pending before the Wisconsin Supreme Court.

Pursuant to due notice, a hearing was conducted by the Division of Hearings and Appeals in Milwaukee on October 18, 19 & 20, 2004 before the undersigned Administrative Law Judge ("ALJ"). The Parties filed simultaneous principal and responsive briefs pursuant to an established briefing schedule, with the final responsive briefs being filed on December 30, 2004. Also, the Northeast States for Coordinated Air Use Management ("NESCAUM") was granted leave to file a brief as *amicus curiae*, which was filed on November 30, 2004.

In accordance with Wis. Stat. §§ 227.47 and 227.53(1)(c), the PARTIES to this proceeding are certified as follows:

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Summary of Issues and Rulings

On May 21, 2004, the Petitioners duly filed an "Issues List and Statement of Requested Relief." By orders dated August 3, 2004, and August 30, 2004, the ALJ delimited the scope of the contested case hearing by striking certain issues and pre-filed evidence from consideration, and delimiting the scope of other certain issues. The ALJ recasts the issues that remain and that were litigated in the contested case hearing as follows:

1. Did the DNR err in excluding IGCC from its BACT/LAER analysis of the SCPC units? (Petitioners' Issues 11 & 12).

RULING: The DNR did not err.

2. Did the DNR err in not establishing a more stringent mercury emissions limit for the IGCC unit? (Petitioners' Issue 10).

RULING: The DNR did not err.

3. Did the DNR comply with the requirement that it determine that the benefits of the proposed project significantly outweigh its environmental and social costs based upon an analysis of alternative sites, sizes, production processes and environmental control techniques? (Petitioners' Issues 6, 7 & 8).

RULING: The DNR complied with the requirement.

4. Did the DNR err in determining that all major stationary sources operated by Wisconsin Electric in the state were in compliance or on a schedule of compliance with all applicable emission limits? (Petitioner's Issue 9).

RULING: The DNR did not err.

There being no demonstrated error in the DNR's issuance of the Air Pollution Control Construction Permit number 03-RV-166, the issuance of the permit is accordingly AFFIRMED.

FINDINGS OF FACT

Background

1. On June 18, 2002, and in subsequent submittals, the applicant, Wisconsin Electric Power Company ("Wisconsin Electric"), submitted an application (the "Application") to the Wisconsin Department of Natural Resources ("DNR") for an air pollution control construction permit under Wis. Stat. § 285.60 and related administrative regulations. The DNR determined the Application to be complete in October 2003.

2. The Application sought a permit to construct a three-unit generating station located on and adjacent to property of Wisconsin Electric's existing Oak Creek Power Plant ("OCPP").

3. The proposed project is to be known as the Elm Road Generating Station ("ERGS"). The ERGS would be situated along the shore of Lake Michigan in both the City of Oak Creek and the Town of Caledonia.

4. All three generating units in the ERGS would use bituminous coal as the original fuel source.

5. Wisconsin Electric and certain affiliated entities also applied for a certificate of public necessity and convenience ("CPCN") for the proposed ERGS project from the Wisconsin Public Service Commission ("PSC") under Wis. Stat. § 196.491(3).

6. The PSC issued a CPCN on November 10, 2003. The PSC approved the construction of two super critical pulverized coal ("SCPC") units, with the first unit to be placed in service in 2009 and the second to be placed in service in 2010. The PSC denied the request to construct the IGCC unit, which Wisconsin Electric had proposed to construct after the SCPC units.

7. The PSC and the DNR prepared an environmental impact statement ("EIS") in conjunction with the CPCN and the various permits and approvals required from the DNR. The PSC issued its final decision on the EIS as part of its CPCN decision. The DNR issued a separate decision on the EIS on December 17, 2003.

8. The DNR issued air pollution control construction permit number 03-RV-166 (the "Permit") on January 14, 2004. The Permit authorizes Wisconsin Electric to construct the two SCPC units and the single IGCC unit as it had applied for, even though the DNR was aware that the PSC had earlier denied the request for a CPCN to build the IGCC unit.

9. The Petitioners requested a contested case hearing on the Permit on February 6, 2004. The DNR granted the hearing request on February 23, 2004.

IGCC as BACT/LAER for SCPC

10. The area in which the ERGS would be located is in attainment of national ambient air quality standards (NAAQS) for all criteria pollutants except for ozone, for which the area has been designated to be a severe nonattainment area.

11. The ERGS is required to be subject to the best available control technology (BACT) for all criteria pollutants except for ozone.

12. Emissions from the ERGS of an ozone precursor, volatile organic compounds (VOC's), must be at the lowest achievable emissions rate (LAER).

13. In the SCPC process, water is heated to higher temperatures and pressure so that the energy content of the steam delivered to the turbines is greater, thereby reducing the amount of fuel consumed per unit of electrical output. In the IGCC process, coal is "gasified" to produce a synthetic gas ("syngas"), which is used as fuel for combustion turbines. Waste heat from this process is also used to produce steam for steam turbine use.

14. The DNR determined not to include IGCC in the BACT/LAER analysis for the ERGS SCPC units for the stated reason that IGCC is a "different type of process technology" from SCPC.

15. The ERGS SCPC and IGCC units would use the same fuel stock of Pittsburgh No. 8 bituminous coal.

16. The ERGS IGCC unit would emit fewer pollutants per unit of power generated than either of the ERGS SCPC units.

17. Gasification of coal in the IGCC production process is not a combustion process. The chemical reactions that occur within an IGCC gasifier are different than the reactions that occur during coal combustion, and the products of those reactions are different.

18. Each of the ERGS SCPC units is composed of a power block, an air quality control equipment block, and the waste handling and byproduct systems.

19. The power block for the ERGS SCPC units is the portion of the plant where coal is burned and electricity is generated. Coal is pulverized to a powdery consistency and then transferred to the boiler where it is combusted as fuel for the steam generator to heat steam. The heated steam turns the steam turbine, which is connected to the electric generator that generates the desired end product -- electricity. The steam then passes through the steam condenser, where it is cooled and then routed to the steam generator.

20. In the air quality control equipment block of the ERGS SCPC units, the exhaust gases from the power block are routed through the air quality control equipment. This equipment includes the following: the baghouse, where particulate is removed; the flue gas desulfurization scrubber, which removes acid gases (SO_2); the selective catalytic reduction (SCR) system, which converts NO_x into nitrogen and oxygen gas; and the wet electrostatic precipitator, which removes sulfuric acid mist and fine particulates.

21. The waste handling and byproduct systems of the ERGS SCPC units include the forced oxidation gypsum plant, the limestone system, the stack, and the systems for handling gypsum and fly ash.

22. An IGCC unit has three separate components: the gasification block, the acid gas removal equipment, and the power block. The gasification block is composed of the air separation unit and the gasifier. The acid gas removal equipment is composed of the acid gas recovery unit and the sulfuric acid plant. The power block is composed of the combustion turbines, heat recovery steam generator, and the steam turbine generator.

23. The ERGS IGCC unit would include the following components: an air separation unit; three oxygen-blown coal gasifiers; two combustion turbines; two heat recovery steam generators; a steam turbine generator; an acid gas recovery unit; a sulfuric acid production facility; a coal slurry/preparation facility; slag handling equipment; and a flare.

24. In order to replace a SCPC coal unit with an IGCC unit, the following major equipment for the SCPC units would have to be removed: components of the power block (steam generator, steam turbine, generator, condenser); air quality control equipment (SCR, baghouse, flue gas scrubber, wet precipitator, stack and limestone handling system); and waste and byproduct handling systems (gypsum system, bottom and fly ash systems).

25. To complete the replacement of a SCPC unit with an IGCC unit, the following equipment would have to be added: an air separation unit; three oxygen-blown coal gasifiers; two combustion turbines; two heat recovery steam generators; a steam turbine generator; an acid gas recovery unit; a sulfuric acid production facility; the coal slurry/preparation facility; slag handling equipment; a storage facility for the slag; a 200-foot tall gas flare.

26. The footprint of an IGCC unit is 200% to 350% the size of an SCPC unit.

27. There are fourteen IGCC facilities generating electricity in the world. Of those fourteen, four are designed to operate with coal as the primary feedstock, and only three of these four are presently operating. These four facilities each have approximately 250 megawatts of generating capacity.

28. No permitting authority has established IGCC as the BACT or LAER for a coal fired power plant.

29. IGCC and SCPC are different process technologies for the production of electricity from coal feedstock. To substitute either of the ERGS SCPC units with an IGCC unit would redefine the design of the ERGS.

Mercury Emissions from ERGS IGCC

30. The Permit set the mercury emissions limit for the ERGS IGCC based upon a determination that the carbon bed filter or equivalent control technology to be employed was capable of achieving 95% removal of mercury from the syngas before combustion.

31. The use of a single carbon bed filter in an IGCC electric generating plant may achieve 99% mercury removal from the syngas, but a removal rate of greater than 95% has never been verified.

32. None of the four IGCC facilities existing worldwide that are designed to generate electricity from coal feedstock has employed carbon bed filter technology to remove mercury from syngas.

33. No IGCC facility anywhere has employed dual carbon bed filters to remove mercury from syngas. It is not known whether use of a dual carbon bed filter to remove mercury from syngas would achieve 99% or greater removal of mercury from the syngas.

Analysis of Alternatives to ERGS

34. The DNR determined that the benefits of construction of ERGS significantly outweighed the environmental and social costs imposed as a result of its location and construction.

35. The DNR summarized its analysis of alternatives in the preliminary determination for the ERGS air permit, which references information provided by Wisconsin Electric, and the Final Environmental Impact Statement (FEIS) that was prepared jointly by the DNR and the PSC.

36. The FEIS assessed the negative economic impact of developing additional generating capacity that risked being unreliable or too expensive.

37. The FEIS assessed the need for sizing the ERGS at approximately 1830 megawatts of generating capacity.

38. Wisconsin Electric considered alternate sites for locating the ERGS and settled on its existing location at OCPP, where there was existing infrastructure and existing land use compatible with the proposed project.

39. The DNR identified and assessed alternatives to the ERGS project in the FEIS. Alternatives considered included: increasing energy efficiency and conservation to reduce overall demand; renewable resources such as wind turbines, biomass, solar power, fuel cells; natural gas; and nuclear power. The FEIS included specific consideration of a proposed natural gas fired generating plant in Fond du Lac County, proposed by Calpine. The DNR also assessed the ERGS IGCC in the FEIS, including addressing the maturity and reliability of IGCC technology.

40. The DNR conducted air quality modeling and determined that emissions from the ERGS project would comply with the NAAQS for criteria pollutants, as well as the PSD increments for those Pollutants.

41. Wisconsin Electric set emissions limits for the ERGS that met all applicable air pollution control standards, including BACT/LAER and required emissions offsets for VOC's. The DNR determined that the ERGS would not likely pose a significant inhalation risk if operated according to required standards.

42. The DNR conducted an additional impact analysis to determine the effects of the project on visibility, secondary growth, soils, and vegetation, and found these impacts to be within acceptable levels under state and federal regulations.

43. The DNR did not attempt to quantify the potential human health impacts resulting either from ERGS air emissions or from alternative power sources or sites for the ERGS.

44. In its analysis of alternative energy sources and alternative sites, the DNR did not attempt to include among the environmental and social costs of the ERGS any quantification in dollar or human terms of the health impacts of the ERGS or of any alternative power sources or sites.

Compliance Status of Other Facilities

45. The DNR contacted its compliance engineers for each facility that Wisconsin Electric operates in Wisconsin. Based upon that review, the DNR determined that Wisconsin Electric's sources were in compliance with all applicable air regulations on the date the ERGS air permit was issued.

DISCUSSION

I. IGCC as BACT or LAER for SCPC Units

The DNR was required to determine that the proposed project utilized the best available control technology ("BACT") for criteria pollutants for which the area was in attainment of national ambient air quality standards (NAAQS). Wis. Stat. § 285.63(3)(a); Wis. Admin. Code Chap. NR 405. The area in which the ERGS is to be located is in attainment of the NAAQS for all criteria pollutants except for ozone.

As for ozone, the DNR was required to determine that the proposed project utilized the lowest achievable emission rate ("LAER"). Wis. Stat. § 285.63(2)(b); Wis. Admin. Code Chap. NR 408. In the case of the ERGS, the LAER would apply to emissions of the ozone precursor "volatile organic compounds" (VOC's).

BACT is defined generally in Wis. Stat. § 285.01(12) as follows:

> "Best available control technology" means an emission limitation for an air contaminant based on the maximum degree of reduction achievable as specified by the department on an individual case-by-case basis taking into account energy, economic and environmental impacts and other costs related to the source.

BACT is defined more specifically within the DNR rule titled "Prevention of Significant Deterioration," Wis. Admin. Code Chapter NR 405, as follows:

> "Best available control technology" or "BACT" means an emissions limitation, including a visible emissions standard, based on the maximum degree of reduction for each air contaminant subject to regulation under the act which would be emitted from any proposed major stationary source or major modification which the department, on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including clean fuels, fuel cleaning or treatment or

> innovative fuel combination techniques for control of the air contaminant. . . .

Wis. Admin. Code § NR 405.02(7).

The DNR rule titled "Construction Permits for Direct Major Sources in Nonattainment Areas," Chapter NR 408 of the Wisconsin Administrative Code, contains the substantially identical definition of BACT in section NR 408.02(4) as that set forth above in Chapter NR 405.

The more detailed definition of BACT in the Wisconsin Administrative Code echoes the definition of BACT contained in the federal Clean Air Act, which is as follows:

> The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this title emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant….

42 U.S.C. § 7479(3).

LAER, the emissions limitation that must be established for ERGS for VOC's, is defined in Wis. Stat. § 285.01(23) as follows:

> "Lowest achievable emission rate" means the rate of emission which reflects the more stringent of the following:
>
> (a) The most stringent emission limitation which is contained in the air pollution regulatory program of any state for this class or category of source, unless an applicant for a permit demonstrates that these limitations are not achievable; or
>
> (b) The most stringent emission limitation which is achieved in practice by the class or category of source.

The DNR employs EPA's recommended "top down" methodology for BACT and LAER analysis. The "top down" methodology requires an applicant first to rank order control technologies in descending order of effectiveness. As to BACT analysis, the top alternative must be selected as the BACT for a pollutant unless it is shown that technical considerations, or energy, environmental, or economic impacts, justify a conclusion that this most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on, until the BACT is established. See *ADEC v. EPA*, 540 U.S. 461, 475-76 (2004), quoting EPA's "New Source Review Workshop Manual (Draft Oct. 1990)" [hereinafter referred to as "NSR Manual"].

The principal difference in BACT and LAER analysis is that LAER analysis does not consider economic factors, except to the extent that LAER is not considered "achievable" if the cost of the control is determined to be prohibitive.

During the application review process, counsel for one of the Petitioners asked the DNR to consider IGCC in its analysis of BACT and LAER for the proposed SCPC units. (Ex. 53). The Secretary of the DNR provided a written response to this request, stating that BACT and LAER analysis "does not specifically allow for consideration of different process technologies." (Ex. 54). The Secretary recognized that while SCPC and IGCC both utilize coal as feedstock, "they do so using very different methods." The Secretary concluded that IGCC and SCPC were "different process technologies," so that the DNR did not intend to include IGCC in the top down BACT/LAER review for the SCPC units. Consistent with the Secretary's response, the DNR did not consider IGCC process technology in its analysis of BACT and LAER for the proposed SCPC generating units. The Petitioners contend that the DNR was required to do so by law.

The DNR and Wisconsin Electric assert that "production processes" or "available methods, systems and techniques" for pollutant reduction that would "redefine the design of the source" are not required to be included in BACT/LAER analysis. The most direct statement of this principle is set forth in the <u>NSR Manual</u>, which the Supreme Court had quoted at length in *ADEC v. EPA.* The salient portion of the <u>NSR Manual</u> provides as follows:

> CONSIDERATION OF INHERENTLY LOWER POLLUTING PROCESSES/PRACTICES
>
> Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives. For example, applicants proposing to construct a coal-fired electric generator have not been required by EPA as part of a BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product (in this case electricity). However, this is an aspect of the PSD permitting process in which states have the discretion to engage in a broader analysis if they so desire. Thus, a gas turbine normally would not be included in the list of control alternatives for a coal-fired boiler. However, there may be instances where, in the permit authority's judgment, the consideration of alternative production processes is warranted and appropriate for consideration in the BACT analysis. A production process is defined in terms of its physical and chemical unit operations used to produce the desired product from a specified set of raw materials. In such cases, the permit agency may require the applicant to include the inherently lower-polluting process in the list of BACT candidates.

The evidence establishes that the design of the ERGS as proposed by Wisconsin Electric would be redefined if IGCC units were substituted for either or both of the proposed SCPC units. The DNR did not err in not including IGCC in the BACT/LAER analysis for the SCPC units.[1]

The SCPC and IGCC units employ radically different processes to produce electricity from coal. These different processes require radically different physical plants. The main commonality is that, as proposed by Wisconsin Electric, both types of units would use coal as the fuel stock (though IGCC plants can be constructed to use fuel stocks other than coal, such as petroleum coke). Beyond the fuel stock, however, there are few similarities between IGCC and SCPC units.

A SCPC unit combusts pulverized coal to create electricity. An IGCC unit "gasifies" the coal in a chemical reaction, and thereafter combusts the syngas product to power its combustion turbines.

An IGCC unit employs a chemical reaction to convert coal into a gaseous stream that consists primarily of hydrogen and carbon monoxide. The raw syngas is cleaned before it is fed to a combined cycle combustion turbine and combusted. This syngas combustion in a combined cycle combustion turbine bears greater similarity to a natural gas combustion turbine than it does to a coal-fired power plant boiler. (Tr. 839). Combustion turbines used to combust syngas in an IGCC plant are similar to those employed in a natural gas fired power plant. (*Id.*). Combustion turbines are designed for gaseous or liquid fuels and cannot burn pulverized coal. (Tr. 754). Combustion turbines designed for an IGCC plant could not be used in a SCPC plant. (*Id.*).

An IGCC unit includes a number of components that do not exist in a SCPC plant. These include the following: a cryogenic air separation unit, which generates oxygen for the gasifier and nitrogen for the combustion turbine (Tr. 752); coal gasifiers, which chemically convert a mixture of coal and water into synthetic gas ("syngas") and acid gas (Tr. 753); an acid-gas recovery unit, which separates out the sulfur from the syngas (Tr. 755); a coal-slurry production facility (Tr. 755); slag handling equipment (Tr. 756); a sulfuric acid production facility (Tr.753); a 200-foot tall flare (tr. 756); a heat recovery steam generator (Tr. 754).

An SCPC unit includes components that do not exist in an IGCC unit. These include components of the power block (steam generator, steam turbine, generator, and condenser), the air quality control equipment (baghouse, flue gas scrubber, the forced

[1] The pre-hearing motions of Wisconsin Electric and the DNR for summary judgment on this issue were denied in the ALJ's order dated August 3, 2004 upon the conclusions that the record on summary judgment was "insufficient to establish as a matter of law that DNR acted within the law in determining not to identify IGCC in the BACT/LAER analysis for the coal-fired SCPC units" and that "[d]evelopment of a fuller factual record will lead to a more informed decision on these potentially complicated and mixed questions of law and fact." Order, p. 12. The factual record on this issue has now been fully developed and establishes that the DNR did not err in excluding IGCC from its BACT/LAER analysis for the SCPC units.

oxidation the wet precipitator, the limestone system, the stack), and the byproduct and waste handling systems, including the gypsum plant.

Because of the different processes and components of IGCC and SCPC, the footprint for an IGCC unit would be from two to three and one-half times the size of the footprint of an SCPC unit with similar generating capacity. Exhibits, 69, 70, and 71 aptly depict the different processes and components of the two types of power plants.

Another innate difference between IGCC and SCPC units is the different regulatory treatment of their respective combustion technologies. The new source performance standards (NSPS) for the combustion units of a SCPC unit are specified by Section NR 440.20 for "electric steam generating units," Wis. Admin. Code, while the NSPS for the gas combustion turbines of the IGCC unit are specified by section NR 440.50, respecting "stationary gas turbines." These different regulatory treatments support the conclusion that IGCC and SCPC are different process technologies, and that to substitute one for the other would redefine the design of the source.

The <u>NSR</u> <u>Manual</u> illustrates the "redefining the design of the source" limitation on BACT analysis with one concrete example. The manual instructs that requiring an applicant for a coal-fired power plant to construct a natural gas-fired plant would be an example of redefining the design of the source that BACT analysis does not require. Thus, the longstanding EPA protocol in administering the statutory BACT requirement under the federal Clean Air Act and implementing regulations (which are mirrored by Wis. Stat. Chapter 285 and DNR rules) is to exclude a natural gas-fired power plant from the BACT analysis for a coal-fired power plant.

The emissions from a syngas-fired IGCC unit would be significantly less than emissions from the proposed SCPC units, just as the emissions from a natural gas-fired plant are significantly less than from any coal-fired plant. Substantial design and process differences exist between syngas-fired and coal-fired plants, as they exist between natural gas and coal-fired plants. (Tr. 838-39). SCPC and IGCC thus represent "different process technologies," as characterized by the Secretary of the DNR. (Ex. 54). The great weight of the evidence demonstrates that substitution of IGCC's different process technology for either or both of the proposed SCPC units at the ERGS would "redefine the design of the source," so that inclusion of IGCC in the BACT analysis for the SCPC units is not required.

The approach described in the <u>NSR</u> <u>Manual</u> is consonant with the regulatory definition of BACT, which requires considering the "*application* of production processes or available methods, systems and techniques" to control contaminants from a "proposed" source. Wis. Admin. Code §§ 405.02(7) [emphasis supplied]. The source as proposed by Wisconsin Electric included two coal-fired SCPC units. IGCC is not a "production process" or an "available method, system, or technique" that can be *applied* or incorporated into the design of an SCPC unit. Rather, IGCC is an altogether different method of generating electricity that would involve the wholesale substitution of one type of physical plant for another. The definition of BACT allows for the exclusion from the top down analysis of a "production process or available method, system or technique" that can not be applied or incorporated into a proposed source without fundamentally altering the source as proposed. As the NSR Manual puts it, the BACT requirement is not "a means to redefine the design of the source when considering available control alternatives."

The NSR Manual recognizes that permitting authorities may exercise discretion to require an applicant to include control technologies and processes in the BACT analysis that could result in a redefinition of the design of the source. It is apparent that this is what the permitting authorities in Illinois, New Mexico, and West Virginia have done by recently considering IGCC in the BACT analysis for coal-fired power plants.[2] In contrast, permitting authorities in Wyoming (Ex. 77), Montana (Ex. 76; Tr. 855-56), and Kentucky (Ex. 78) have recently determined not to include IGCC in the BACT analysis for a coal-fired plant on the rationale that selection of IGCC as BACT would redefine the design of the proposed coal-fired plants. The varying determinations of different state permitting authorities on inclusion of IGCC in a BACT analysis for a coal-fired plant reflect the discretion that the law accords them to include in the BACT analysis a production process that would redefine the design of the source. See *In re Kendall New Century Development*, PSD Appeal No. 03-01, 2003 WL 21213227, n.14 (E.P.A. April 29, 2003)("redefinition of the source is not always prohibited" but "is a matter for the permitting authority's discretion").

The decision *In the Matter of Hawaiian Commercial & Sugar Co.*, PSD Appeal No. 92-1, 4 E.A.D. 95, 99-100, 1992 WL 191948 (July 20, 1992), is instructive on this issue. There the state permitting authority issued a permit for the construction of a boiler that would be fueled by coal, fuel oil, or biomass. The permit was challenged in part on the basis that the permitting authority should have required a combined cycle facility that would not be fueled by coal. The Environmental Appeals Board concluded that regulations for determination of BACT "do not mandate that the permitting authority redefine the source in order to reduce emissions." *Id.* at 99. The board ruled that requiring a combined cycle facility over the coal-fired facility "would in effect redefine the source." *Id.* at 100. The Board quoted at length the NSR Manual respecting "redefining" a source in BACT analysis, observing that "the [state] permitting authority is entitled to a wide latitude in how broad a BACT analysis it wishes to conduct in this regard." *Id.* at 99-100. Accord, *In re Kendall New Century Development* (affirming state permitting authority's determination that the addition of heat recovery steam generator to transform a single cycle

[2]Of these states, permitting authorities in Illinois and West Virginia have made BACT determinations, and neither selected IGCC as BACT or LAER for the proposed coal fired units. The permitting authority in New Mexico has yet to make its BACT determination.

gas turbine to a combined cycle turbine system would "redefine the source" and was not required in BACT analysis).

The range of control options evaluated under LAER is generally the same as those evaluated under a BACT analysis. (Tr. 237). The principal difference between the LAER and BACT analysis is the substantially diminished role that cost considerations have in establishing the LAER for a source or for a particular emissions unit within a source. As with BACT analysis, the DNR was not required to include IGCC in establishing the LAER for VOC's for either or both of the SCPC units. To require this would likewise have resulted in a redefinition of the design of the source.

The DNR considered the Petitioners' assertion that the DNR should consider IGCC in the BACT/LAER analysis for the proposed SCPC units. The DNR reasonably applied settled protocols in the conduct of the established methodology in determining not to include IGCC in the top down BACT/LAER analysis for the SCPC units.

II. IGCC Mercury Emissions

The Petitioners claim that the emission rate for mercury for the permitted IGCC unit is "insufficiently stringent because DNR failed to consider available techniques that could lower mercury emissions from IGCC units." (Petitioners' Issue 10). The Permit set the mercury emissions limit for the IGCC unit based upon a determination that "carbon bed filter" control technology would achieve 95% removal of mercury from the syngas before combustion. (Ex. 43, p. 118).

A verified 95% removal rate utilizing a single carbon bed filter has been achieved at an IGCC plant operated by Eastman Chemical Company. (Ex. 13). The Eastman Chemical plant is not an electricity generating facility, however, but rather it uses IGCC to create syngas to use as a feedstock to produce chemicals. No existing IGCC power plant utilizes the carbon bed filter technology to remove mercury from syngas, and thus there is no historical data on how this technology would perform as part of an IGCC power plant.

In Wisconsin Electric's permit application, its analysis for mercury included discussion of the carbon bed filter technology employed at the Eastman Chemical plant, stating that "we expect that the use of carbon should provide approximately 99% overall mercury control." (Ex. 39, Att. 4, p. 6). It is apparent that Wisconsin Electric viewed carbon bed filter technology to be capable of being applied in its proposed IGCC unit. (Ex. 13, p. 22). The DNR apparently agreed and included use of carbon bed filter or similar technology in establishing the mercury emissions limit.

In September 2002, a study prepared for the Department of Energy titled "The Cost of Mercury Removal in an IGCC Plant" indicated that mercury removal of better than 99% may be achievable by using *dual* carbon bed filters in a series, in contrast to a single carbon bed filter as employed at the Eastman Chemical plant. (Ex. 13). The report noted, however, that mercury removal from syngas at a rate higher than 95% has "not yet been verified." (Ex. 13, p. 5). The use of *dual* carbon bed filter technology has not been employed in any IGCC plant.

Section NN of the Permit requires Wisconsin Electric to "submit information for reevaluating BACT … at least 18 months prior to the commencement of construction of any permitted processes that may have not begun construction within eighteen months from the date of the issuance of the final permit." (Ex. 43, p. 140). The DNR's formal response to a public comment that the proposed ERGS IGCC mercury emissions limit was insufficiently stringent makes it apparent that the DNR expected to revisit the mercury emissions limitation for the ERGS IGCC unit before construction of the unit began:

> The BACT/LAER analysis for the IGCC unit is based on the current state of technology, the best engineering judgment of the performance of similar units and current expected economics, energy and other impacts. If construction of the IGCC unit does not begin within 18 months of the permit issuance, then Wisconsin Electric is required to undergo a reevaluation of the BACT/LAER in the future, but no later than 18 months prior to beginning construction. The current BACT/LAER analysis cannot predict what may be considered as BACT/LAER several years in the future.

(Ex. 40, Tab 4.D.).

Wisconsin Electric expected to be able to achieve "approximately 99% overall mercury control" with a single carbon bed filter. (Ex. 39, Attachment 4, page no. 6)(Tr. 818). However, since a mercury removal rate of greater than 95% has never been verified, the prospect of achieving a greater reduction is not a certainty. (Ex. 39, Attachment 4, page numbered "6")(Tr. 818). With respect to the use of a single carbon filter, achieving 99% mercury removal remains a rate that is considered possible, but possible in theory only. (Tr. 818-19). And with respect to potential use of *dual* carbon filters, achieving 99% or better mercury removal is the unexplained and unconfirmed conclusion of the authors of the September 2002 DOE study. (Ex. 13).

When the Permit was issued it was a virtual certainty that Wisconsin Electric would not under any likely scenario begin construction of the permitted IGCC unit within eighteen months of the January 14, 2004 issuance of the Permit. Wisconsin Electric thus will likely be required to resubmit to the DNR updated information on control technology for mercury before commencing construction on the permitted IGCC unit. If the time ever comes for Wisconsin Electric to commence construction of the permitted IGCC unit, Wisconsin Electric's reevaluation of control technology for mercury should explicitly address the efficacy of a dual carbon bed filter technology posited by the September 2002 study commissioned by the DOE. Given the expectation for achieving 99% reduction utilizing a single carbon bed filter, the DNR acted reasonably in establishing the IGCC mercury emissions limitation at an anticipated 95% removal rate to allow for a margin to assure that the permittee would achieve compliance consistently. See *In re Masonite Corp.*, 5 E.A.D. 551, 560-61 (EAB 1994)(where an expected optimal removal efficiency had never been proven, a permitting authority has "a certain degree of discretion to set the emissions limitation at a level that does not necessarily reflect the highest possible control efficiency, but will allow the permittee to achieve compliance consistently").

III. Alternatives Analysis

By virtue of the ERGS being located in a nonattainment area for ozone, the DNR was required to conduct an "analysis of alternatives" before issuing the permit. Section 285.63(2)(d), Stats., prescribes this "alternatives analysis" as follows:

> (2) REQUIREMENTS FOR PERMITS FOR NEW OR MODIFIED MAJOR SOURCES IN NONATTAINMENT AREAS. The department may approve the application for a construction permit ... for a major source that is a new source or a modified source and is located in a nonattainment area if the department finds that all of the following conditions are met:
>
> * * * *
>
> (d) *Analysis of alternatives.* Based on an analysis of alternative sites, sizes, production processes and environmental control techniques for any major source that is located in an area designated under 42 USC 7407(d), that the benefits of the construction or modification of the major source significantly outweigh the environmental and social costs imposed as a result of the major source's location, construction or modification.

In implementing this statutory requirement, the DNR has by rule required an applicant for a permit to "demonstrate to the satisfaction" of the DNR that the proposed source satisfies the required alternatives analysis:

> By means of an analysis of alternative sites, sizes, production processes and environmental control techniques for proposed new or modified stationary source, the owner or operator of the proposed stationary source or modification can demonstrate to the satisfaction of the department that the benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction or modification.

Wisconsin Admin. Code § NR 408.08(2).

These provisions of state law establish the same requirement contained in the federal Clean Air Act, 42 U.S.C. 7503(a)(5), enacted in 1977, which imposed this and other requirements on proposed sources located in nonattainment areas. 42 U.S.C. §§ 7501-08.

The statutes and rules contain no express standards respecting the particular content of the "alternatives analysis," and neither the DNR nor the EPA has promulgated a rule or regulation specifying a methodology for the required analysis. *In re Campo Landfill Project*, NSR Appeal No. 95-1, 6 E.A.D. 505, 1996 WL 344522 (EAB 1996); *City of Seabrook v. EPA*, 659 F.2d 1349, 1361-63 (5th Cir. 1981). The Environmental Appeals Board has characterized the "alternatives analysis" as "inherently subjective." *Campo*

Landfill Project, 6 E.A.D. at 521. As recently as last year, EPA Region V (which encompasses Wisconsin) officially expressed its view that a "case-by-case" approach to the alternatives analysis comports with federal law. (Ex. 88).

In the DNR's preliminary determination on Wisconsin Electric's application, the DNR found that the ERGS project withstood this alternatives analysis. (Ex. 39: Vol. 1, p. 67; Vol. 2, Tab 13). The Department's analysis referred to the Final Environmental Impact Statement ("FEIS") dated July 2003 that was prepared jointly by the PSC and the DNR, particularly Chapters 3 and 4, which are respectively titled "Need for Baseload Capacity in Southeastern Wisconsin" and "Alternatives to Proposed Project." The DNR relied as well on the PSC's determination that increased capacity was needed to address energy needs in the state, and on the DNR's own determinations that the proposed project would meet BACT/LAER emission limits and all applicable air quality requirements. (Ex. 40, Tab 4-D, response to comments 7 & 8). Upon issuing the Permit, the DNR made the ultimate finding that the application met the criteria of Wis. Stat. § 285.63, which includes the "alternatives analysis" requirement. (Ex. 39, p. 3, "Finding of Fact" 6).

The Petitioners claim the alternatives analysis was inadequate. The gist of their contention is that the DNR should have quantified the "environmental and social costs" resulting from the emissions from the proposed project as well as from "alternative sites, sizes, production processes, and environmental control techniques," such as for example natural gas fired units or IGCC units. After having quantified the "environmental and social costs" of the various alternatives, the Petitioners contend that the DNR then should have weighed these alternative costs in determining whether the benefits of the proposed project "significantly outweighed" its environmental and social costs. The Petitioners assert that the required alternatives analysis is not complete until these alternative costs are quantified, compared, and then weighed against the benefits of the project. In their argument, the Petitioners have particularly focused on human health impacts as "environmental and social costs" that it asserts could have been empirically determined, including predicting the economic health care costs caused by emissions from a specific source.

The DNR certainly could have attempted to conduct such an alternatives analysis, if in its discretion it had deemed it possible, practicable, or necessary in assessing the environmental and social costs of the project. Nothing in the law or administrative rule, however, requires utilization of this form of analysis, either in general or with respect to this particular permit.

There was abundant information before the DNR from which it could reasonably (1) compare the proposed project with alternative sites, sizes, production processes and environmental control techniques, and then (2) weigh the environmental and social costs of the proposed project and alternatives against the benefits of the proposed project. This information included the material submitted and collected in the permitting process and in the preparation of the joint FEIS with the PSC. An air permitting authority may utilize an environmental impact statement prepared by another agency in making an alternatives analysis under the federal Clean Air Act. See *In re Campo Landfill* (EPA regional office did not err in relying on an environmental impact statement prepared by another federal agency as part of its "alternatives analysis"). Wisconsin statutes contemplate the DNR and the PSC engaging in a coordinated process in the review and processing of applications for construction of an electric generating facility. See Wis. Stat. § 196.491(3).

A. *Benefits of the proposed project.*

In making its alternatives analysis, the DNR expressly relied on Chapter 3 of the FEIS, which explored the need for the proposed 1,830 megawatts of electricity generating capacity in southeastern Wisconsin in the coming years. The FEIS observed that the absence of sufficient baseline capacity in southeastern Wisconsin would lead to an "unreliable" electric system that "would impose a tremendous economic cost on the economy" that would be difficult to estimate but that "would likely be substantial in dollar and qualitative terms." (Ex. 41, Vol. 1, p. 75).

B. *Alternative Sites.*

The FEIS recounts that Wisconsin Electric preliminarily considered 140 potential sites. Many of these were eliminated "through a process that evaluated the sites on various social, environmental, and technical/economic parameters that were embodied in 55 screening criteria and weighted according to their importance." (Ex. 41, Vol. 1, p. 95). This winnowing process explicitly evaluated "environmental and social" factors (i.e., "costs"), as is required in an "alternatives analysis" under NR 408.08(2). From these 140 original site possibilities, five site alternatives were identified, each in a different county -- Milwaukee, Kenosha, Sheboygan, Ozaukee, and Oconto. An important factor in the selection of these five sites was the ability to locate all three proposed units at a single site, and the potential re-use of existing infrastructure, as at the "brownfield" sites in Milwaukee and Kenosha counties. (Ex. 41, Vol. 1, p. 95). The fact that a new facility is proposed on a brownfield site and will be able to utilize existing facilities is a valid basis upon which to reject other sites for purposes of the alternatives analysis. See *In re Operating Permit Formaldehyde Plant Borden Chemical, Inc.*, Permit No. 2631-VO, Petition No. 6-01-1 (Dec. 22, 2000).

C. *Alternative Sizes*

The FEIS concluded that Wisconsin Electric's forecast of demand in ten years was "not unreasonable" but "may be on the high side." (Ex. 41, p. 45). In its assessment of alternatives, the FEIS considered the option of not building the proposed project. The FEIS also considered the alternative of increasing "energy efficiency" (which connotes conservation, load management, fuel switching) as a means of reducing the need for additional generating capacity. (Ex. 41, Vol. 1, pp. 48-53). The FEIS provided sufficient information on the required size of the electric generating facility to enable the PSC to determine whether the proposed project was appropriately sized to meet future needs.

Before it issued the Permit, the DNR certainly knew that the PSC had determined not to issue a CPCN for the IGCC unit, applying its expertise in assessing the need and the state of IGCC technology for generating power. It was appropriate for the DNR to rely on the expertise of the PSC to determine the size of the project that would best serve the public convenience and necessity, and for the DNR to focus on the air quality impacts of the proposed project.

D. *Alternative Production Processes and Environmental Control Techniques*

The FEIS includes an assessment of fuel alternatives including noncombustible renewable resources (wind, solar, hydro), and combustible renewable resources (fuel cells fueled by hydrogen, and biomass fuel). (Ex. 41, Vol. 1, pp. 53-61). This analysis included a discussion of the availability and efficacy of these renewable resources and processes as well as recognition that they generally constituted a cleaner means of generating electricity than coal or gas combustion, particularly the noncombustible renewable resources.

Chapter 4 of the FEIS also included an analysis on the relative merits of natural gas combined cycle or simple cycle plants, or purchasing the electricity from an independent power producer, including specifically consideration of a natural gas fired project in Fond du Lac County. (Ex. 41, Vol. 1, pp. 65, 417-30). The FEIS included assessments of the relative environmental impacts of this Fond du Lac County project. *Id.*

Despite the present statutory prohibition on construction of new nuclear power plants, the FEIS nevertheless considered nuclear power among the potential alternatives because the construction bar could be lifted by the year 2010. (Ex. 41, Vol. 1, pp. 76-77).

The FEIS analyzed the environmental impacts of natural gas extraction and compared it with the impacts from coal mining and coal transport. The FEIS explored in detail the uncertainties that would accompany increased reliance on natural gas power plants. (Ex. 41, pp. 79-93). The FEIS also assessed the proposed ERGS IGCC and SCPC units, noting differences in capacity and efficiency factors, as well as obstacles to reliability of IGCC compared to SCPC. (*Id.* at 103-20).

The FEIS elsewhere includes extensive information on the differing levels of emissions from SCPC units and IGCC units (Ex. 41, Vol. 1, Chap 7), as well as a comparison of air emissions from the two proposed SCPC units compared emissions from similar sized natural gas-fired units. (Ex. 41, Vol. 1, pp. 429-430). Between the three processes, SCPC has the greatest volume of emissions per unit of power generated, while as between IGCC and natural gas, natural gas is less polluting for some pollutants but higher for others. The DNR recognized that fewer emissions means lower environmental and social costs, though it observed nonetheless that the inhalation risk posed by the proposed project would not “be likely to cause to a significant inhalation risk.” (Ex. 41, Vol. 3, p. 20).

The DNR certainly knew that natural gas and IGCC plants emit fewer pollutants than SCPC plants. As addressed above in part I of this Discussion, the DNR reasonably determined not to include those production processes as control technologies in establishing the BACT/LAER for the SCPC units. The BACT analysis is by definition a case-by-case analysis that takes into consideration "energy, environmental and economic impacts and other costs," Wis. Admin. Code § NR 408.02(4), and to this extent bears relevance to the environmental and social costs that are to be considered in an alternatives analysis. The DNR expressly took into account the effect of BACT/LAER analysis on the ERGS emissions in its assessment of the "environmental and social costs" in the alternatives analysis. (Tr. 387). This was an appropriate consideration, and it was similarly appropriate for the DNR to consider that the proposed project would comply with the "offset" requirements for VOC's, which would lead to a net reduction of current levels of VOC emissions. See, e.g., *Borden Chemical,* at 39-40.

E. *Environmental and Social Costs of the Proposed Project*

Chapter 7 of the FEIS was authored principally by the DNR and extensively addressed the air quality impacts of the proposed project. (Ex. 41, Vol. 1). The FEIS recognized that "coal-burning power plants can create harmful impacts to the environment and to human health" and that "[r]egardless of whether the facility meets existing standards, there is often a question whether sensitive individuals are adequately protected." *Id.* at 134-35. Elsewhere in the FEIS, the DNR recognized that emissions from coal-fired power plants, even those that do not result in any violation of state or federal standards, carry environmental and social costs, implicitly recognizing that these emissions have no intrinsic benefit. (Ex. 41, Vol. 3, pp. 20-21). The FEIS did not attempt to quantify those health impacts in human or dollar terms for either the project as proposed or for any alternative forms of the project. The FEIS noted, that "[p]ast DNR analyses … have found that, from an inhalation perspective, the risks resulting from well controlled facilities with tall stacks are low," so that a "facility that meets applicable Wisconsin DNR requirements would not be likely to cause a significant inhalation risk." Id. at 20.

F. *Weighing Costs and Benefits*

The EPA has recently adopted an air dispersion model known as CALPUFF as the "preferred technique for assessing long range transport of pollutants and their impacts on Federal Class I areas." 68 Fed. Reg. 18,440 (April 15, 2003). Some experts in the field believe the CALPUFF model and similar models may be employed to provide a reasonably reliable calculation of the human health costs and impacts of air emissions from a specific source. (Ex. 44, Tab 2, p. 4019-20). Indeed, in the process of developing the FEIS, the Petitioners had submitted a study prepared by a Harvard University professor and associates that relied at least in part on the CALPUFF model. This study undertook to quantify the human health impacts that would result from the $PM_{2.5}$ emissions from the ERGS as proposed and under alternative configurations, including a scenario of powering the ERGS wholly by natural gas. (Ex. 44, Tab 1, pp. 4013-14).

Despite the apparent emergence of analytical techniques that attempt to quantify the adverse health impacts from a particular source with some reasonable degree of reliability, the Petitioners have not identified any air permit authorities in any jurisdiction that have required such quantification as a component of an alternatives analysis. Presumably, there are none. No precedent from any state or federal authority suggests that such a study should be conducted as a part of an alternatives analysis under the federal Clean Air Act or its state analogs. Absent any such precedent, the burden of demonstrating that the DNR acted unreasonably in not conducting this type of study is quite high. The Petitioners have not met this burden.

Owing in large part to its "inherently subjective" nature (*Campo Landfill* at 521), there is ample room within an alternatives analysis for reasonable persons to disagree on whether the benefits of a proposed project significantly outweigh its environmental and social costs. This is certainly true with respect to the ERGS project. Though reasonable persons may disagree, it falls to the DNR to see that an alternatives analysis is done and to make a determination upon it. The Petitioners have not demonstrated that the matters that the DNR either considered or did not consider in this endeavor were unreasonable or that the alternatives analysis failed to meet minimum legal requirements.

IV. <u>Compliance of Other Wisconsin Electric Facilities</u>

Because the ERGS is located in a nonattainment area for ozone, the DNR was required to determine that all of Wisconsin Electric's other major sources in Wisconsin "are in compliance, or on a schedule to come in compliance with all applicable emissions limitations and standards under the federal clean air act." Wis. Stat. § 285.63(2)(c); <u>see also</u> Wis. Admin. Code § NR 408.08(1); 42 U.S.C. § 7503(a)(3).

In its permit application, Wisconsin Electric stated that all its major sources in Wisconsin were in compliance with applicable emissions limitations. (Ex. 40, Attachment 4-D, response to comment 9). The DNR permit engineer responsible for processing the application consulted the DNR's air compliance engineers involved in inspecting and monitoring Wisconsin Electric's major sources. These compliance engineers had monitoring and compliance records available to them, and they confirmed that all of Wisconsin Electric's major sources in the state were in compliance with all applicable emission limits. (*Id.*; Tr. 413-14, 419, 434-35).

Wisconsin Electric's permit application was completed on October 1, 2003. Some five months earlier, on April 29, 2003, the United States had filed a complaint against Wisconsin Electric in federal district court alleging that since 1982 Wisconsin Electric had modified and thereafter operated coal-fired electricity generating units in Wisconsin and Michigan without first obtaining required permits. (Ex. 46). The same day that the complaint was filed, a proposed "Amended Consent Decree" was also filed with the federal district court, that if approved by the district court would resolve the dispute. The proposed Amended Consent Decree recited that Wisconsin Electric denied having violated the air pollution control laws as alleged in the complaint. (Ex. 48). The federal district court has not yet approved or disapproved the proposed consent decree. (Ex. 47).

The DNR was aware of the federal lawsuit and proposed amended consent decree at the time that it determined Wisconsin Electric to be in compliance with all applicable emissions limitations. The DNR was not obliged by virtue of the federal complaint to make an independent determination on the validity of the allegations in the federal complaint. It was entitled to reasonably rely on periodic compliance reports and records respecting Wisconsin Electric's other major sources in the state in determining that Wisconsin Electric was in compliance with all applicable emissions limits. No evidence beyond the bare allegations of the federal complaint were offered in the contested case hearing that would show that Wisconsin Electric was not in compliance with all applicable emissions limitations when the DNR issued the Permit. The DNR did not err in allowing the matter alleged in the federal lawsuit to take its course and in reasonably relying on the information in its possession regarding Wisconsin Electric's compliance with emission standards. The DNR reasonably concluded that other major sources owned or operated by Wisconsin Electric in the state were in compliance with all applicable emission limits.

V. Other Issues Raised in Petitioners' Issues List

The Division's Order dated August 3, 2004 limited the scope of the Petitioners' enumerated issues 1, 2, 3, 4, 14 and 15. In their post hearing briefs, the Petitioners have not presented evidence or made any assertions within the remaining scope of issues 1, 2, 3, 4, 14 and 15, so there is nothing further to determine respecting those issues beyond the matters determined by the Order of August 3, 2004.

In their enumerated issue 5, the Petitioners claimed that the "air dispersion modeling upon which the Air Permit is based is flawed" for several stated reasons. The Petitioners have presented no evidence and made no argument respecting issue 5 and have thus not met their burdens of proof and persuasion on this issue. Wis. Stat. § 285.81(1)(b); Wis. Admin. Code § NR 2.13(3)(b). The Petitioners have likewise not met their burdens or proof or persuasion regarding issue 13, which challenges application of hazardous air pollutant regulations.

CONCLUSIONS OF LAW

1. The Division of Hearings and Appeals has authority to hear contested cases relating to air pollution permits. Wis. Stat. §§ 227.43 and 285.81(a). "Following the hearing the [DNR's] action may be affirmed, modified or withdrawn." Wis. Stat. § 285.81(1)(b).

2. The BACT and LAER analyses and the air quality review for the ERGS project complied with all applicable requirements of Wis. Admin. Code §§ NR 405.08 and NR 408.04.

3. An applicant for an air pollution control construction permit is not required to redefine the design of the proposed source in selecting control technologies or production processes for inclusion in the BACT or LAER analysis. Wis. Stat. § 283.63.

4. Selection of IGCC process technology in a BACT/LAER analysis for a SCPC unit would result in redefining the design of the proposed source. The DNR was not required to include IGCC process technology in the top down BACT/LAER analysis for either or both SCPC units for the proposed ERGS. The DNR acted within its discretion in not requiring Wisconsin Electric to include the IGCC process technology in the BACT/LAER analysis for the ERGS SCPC units. Wis. Stat. § 283.63.

5. The DNR reasonably established the ERGS IGCC mercury emissions limitation based upon a verified rate of 95% mercury removal that had been demonstrated by control technology in use in another IGCC plant. Wis. Stat. § 283.63.

6. The DNR considered alternative sites, sizes, production processes and environmental control techniques to the ERGS project. Wis. Stat. §285.63(2)(d); Wis. Admin. Code § NR 405.08(2).

7. The DNR considered environmental and social costs of the ERGS and alternatives to the ERGS. Wis. Stat. §285.63(2)(d); Wis. Admin. Code § NR 405.08(2).

8. The DNR weighed environmental and social costs of the ERGS against its benefits. Wis. Stat. §285.63(2)(d); Wis. Admin. Code § NR 405.08(2).

9. The DNR reasonably determined that the benefits of the ERGS project would significantly outweigh the environmental and social costs that it would impose. Wis. Stat. §285.63(2)(d); Wis. Admin. Code § NR 405.08(2).

10. The DNR reasonably determined that all of Wisconsin Electric's facilities in Wisconsin were in compliance or on a schedule for compliance as of the date of permit issuance. Wis. Stat. § 285.63(2)(b); Wis. Admin. Code § NR 408.08(l).

ORDER

WHEREFORE, IT IS ORDERED that the Department’s issuance of Air Pollution Control Construction Permit No. 03-RV-166 on January 14, 2004 is affirmed.

Dated at Milwaukee, Wisconsin on February 3, 2005.

STATE OF WISCONSIN
DIVISION OF HEARINGS AND APPEALS
819 North 6th Street, Room 92
Milwaukee, Wisconsin 53203-1685

By: ______________________________
William S. Coleman, Jr.
Administrative Law Judge

NOTICE

Set out below is a list of alternative methods available to persons who may desire to obtain review of the attached decision of the Administrative Law Judge. This notice is provided to insure compliance with Wis. Stat. § 227.48 and sets out the rights of any party to this proceeding to petition for rehearing and administrative or judicial review of an adverse decision.

1. Any party to this proceeding adversely affected by the decision attached hereto has the right within twenty (20) days after entry of the decision, to petition the secretary of the Department of Natural Resources for review of the decision as provided by Wisconsin Administrative Code § NR 2.20. A petition for review under this section is not a prerequisite for judicial review under Wis. Stat. §§ 227.52 and 227.53.

2. Any person aggrieved by the attached order may within twenty (20) days after service of such order or decision file with the Department of Natural Resources a written petition for rehearing pursuant to Wis. Stat. § 227.49. Rehearing may only be granted for those reasons set out in Wis. Stat. § 227.49(3). A petition under this section is not a prerequisite for judicial review under Wis. Stat. §§ 227.52 and 227.53.

3. Any person aggrieved by the attached decision which adversely affects the substantial interests of such person by action or inaction, affirmative or negative in form is entitled to judicial review by filing a petition therefor in accordance with the provisions of Wis. Stat. §§ 227.52 and 227.53. Said petition must be filed within thirty (30) days after service of the agency decision sought to be reviewed. If a rehearing is requested as noted in paragraph (2) above, any party seeking judicial review shall serve and file a petition for review within thirty (30) days after service of the order disposing of the rehearing application or within thirty (30) days after final disposition by operation of law. Since the decision of the Administrative Law Judge in the attached order is by law a decision of the Department of Natural Resources, any petition for judicial review shall name the Department of Natural Resources as the respondent. Persons desiring to file for judicial review are advised to closely examine all provisions of Wis. Stat. §§ 227.52 and 227.53, to insure strict compliance with all its requirements.

Woodland Pulp LLC **Washington County** **Baileyville, Maine** **A-215-77-15-A**	**Departmental** **Findings of Fact and Order** **New Source Review** **NSR #15**

FINDINGS OF FACT

After review of the air emission license application, staff investigation reports, and other documents in the applicant's file in the Bureau of Air Quality, pursuant to 38 Maine Revised Statutes (M.R.S.) § 344 and § 590, the Maine Department of Environmental Protection (the Department) finds the following facts:

I. REGISTRATION

A. Introduction

FACILITY	Woodland Pulp LLC (Woodland Pulp)
LICENSE TYPE	06-096 C.M.R. ch. 115, Major Modification
NAICS CODES	322121
NATURE OF BUSINESS	Pulp and Paper Mill
FACILITY LOCATION	144 Main Street, Baileyville, Maine 04694

B. NSR License Description

Woodland Pulp LLC (Woodland Pulp) has applied for a New Source Review (NSR) license to construct and operate two new tissue machines (TM3 and TM4) at their facility located in Baileyville, Maine.

Woodland Pulp previously licensed two tissue machines (TM1 and TM2) in NSR license A-215-77-6-A (issued 3/8/13). In that license, Woodland Pulp accepted an emissions cap in order to keep the project minor. As part of the current project, Woodland pulp has requested the removal of this cap.

C. Emission Equipment

The following are emission units addressed in this NSR license:

Production Equipment

Equipment	Maximum Capacity	Fuel Type	Pollution Control Equipment
TM1 Tissue Machine Dryer Burners	187.4 ADTFP/day[1] 50 MMBtu/hr (total)	N/A Natural Gas	Dust Collectors/Venturi Scrubber Low NO_x Burners
TM2 Tissue Machine Dryer Burners	187.4 ADTFP/day[1] 50 MMBtu/hr (total)	N/A Natural Gas	Dust Collectors/Venturi Scrubber Low NO_x Burners
TM3 Tissue Machine Dryer Burners	276 ADTFP/day[1] 183 MMBtu/hr (total)	N/A Natural Gas	Dust Collectors/Venturi Scrubber Ultra-Low NO_x Burners
TM4 Tissue Machine Dryer Burners	187.4 ADTFP/day[1] 50 MMBtu/hr (total)	N/A Natural Gas	Dust Collectors/Venturi Scrubber Ultra-Low NO_x Burners

1. ADTFP/day = air-dried tons of finished product per day

D. Acronym List

The following acronyms and units of measurement are used in this license:

ADTFP/day	air-dried tons of finished product per day
ADT	air-dried tons
AGL	above ground level
BACT	Best Available Control Technology
BPT	Best Practical Treatment
C.F.R.	Code of Federal Regulations
C.M.R.	Code of Maine Rules
CO	Carbon Monoxide
CO_2e	Carbon Dioxide equivalent
EPA or US EPA	United States Environmental Protection Agency
GHG	Greenhouse Gases
HAP	Hazardous Air Pollutants
LAER	Lowest Achievable Emission Rate
lb	pound
lb/ADT	pounds per air-dried ton
lb/hr	pound per hour

lb/MMBtu	pound per million British thermal units
LDC	lightweight dry crepe
LNB	low NOx burner
M.R.S.	Maine Revised Statutes
MMBtu	Millions of British Thermal Units
MMBtu/hr	Million British Thermal Units per hour
MNWR-Baring	Moosehorn National Wildlife Refuge – Baring Unit
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NOx	Nitrogen Oxides
NSPS	New Source Performance Standards
NSR	New Source Review
NWS	National Weather Service
PM	Particulate Matter less than 100 microns in diameter
PM_{10}	Particulate Matter less than 10 microns in diameter
$PM_{2.5}$	Particulate Matter less than 2.5 microns in diameter
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
RBLC	RACT-BACT-LAER Clearinghouse
SO_2	Sulfur Dioxide
TAD	through-air-dried
ton/hr	ton per hour
ton/yr	ton per year
tpy	ton per year
ULNB	ultra low NOx burner
USEPA	US Environmental Protection Agency
USFWS	US Fish & Wildlife Service
VOC	Volatile Organic Compounds

E. Application Classification

All rules, regulations, or statutes referenced in this air emission license refer to the amended version in effect as of the issued date of this license.

The application for Woodland Pulp does not violate any applicable federal or state requirements and does not reduce monitoring, reporting, testing, or recordkeeping requirements.

The modification of a major source is considered a major or minor modification based on whether or not expected emissions increases exceed the "Significant Emissions Increase" levels as given in *Definitions Regulation*, 06-096 Code of Maine Rules (C.M.R.) ch. 100.

For a major stationary source, the expected emissions increase from each modified or affected unit may be calculated as equal to the difference between the post-modification projected actual emissions and the baseline actual emissions for each NSR regulated pollutant.

1. Baseline Actual Emissions

Baseline actual emissions for existing affected emission units are equal to the average annual emissions from any consecutive 24-month period within the ten years prior to submittal of a complete license application. The selected 24-month baseline period can differ on a pollutant-by-pollutant basis. However, there are no existing emission units which are considered "affected" by this project.

There will be no increase in production from the pulp mill due to this project. The pulp mill operates at or near capacity. Any pulp produced in excess of the mill's needs is sent to the pulp dryer and then shipped off-site. The additional pulp required by this project will simply reduce the amount sent to the pulp dryer. Therefore, none of the pulp mill equipment are considered affected units for this project.

There will be no increase in steam demand from the boilers due to this project. Hot air within the yankee dryer hoods of TM1, TM2, and TM4 will be heated by direct-fired natural gas burners that are included as part of these new emission units. Both the yankee dryer hood and through-air-dryer of TM3 will be heated by direct-fired natural gas burners that are included as part of this new emission unit. The yankee drums on all four TMs are heated with steam, but there is no expected increase in steam load from the facility's boilers. Steam will be diverted from other sources, such as the pulp dryer, which is expected to dry less pulp as a result of this project. Therefore, none of the mill's boilers are considered affected units for this project.

Tissue Machines TM1, TM2, TM3, and TM4 are all conservatively being treated as new units for the purposes of this license. Baseline actual emissions for new equipment are considered to be zero for all pollutants; therefore, the selection of a baseline year is unnecessary.

2. Projected Actual Emissions

Emission units (TM1, TM2, TM3, and TM4) must use potential to emit emissions for projected actual emissions. Those emissions are presented in the following table.

Projected Actual Emissions

Equipment	PM (ton/yr)	PM_{10} (ton/yr)	$PM_{2.5}$ (ton/yr)	SO_2 (ton/yr)	NO_x (ton/yr)	CO (ton/yr)	VOC (ton/yr)	CO_2e (ton/yr)
TM1 (and dryers)	13.0	14.7	13.3	0.1	19.8	18.0	35.4	25,818
TM2 (and dryers)	13.0	14.7	13.3	0.1	19.8	18.0	35.4	25,818
TM4 (and dryers)	13.0	14.7	13.3	0.1	19.8	18.0	35.4	25,818
TM3 (and dryers)	19.2	21.6	19.7	0.5	39.3	66.0	54.7	94,493
Total	**58.2**	**65.7**	**59.6**	**0.8**	**98.7**	**120.0**	**160.9**	**171,947**

__Note:__ PM_{10} and $PM_{2.5}$ emissions are higher than PM emissions due to condensable particulate being included in the definitions of PM_{10} and $PM_{2.5}$ but not in the definition of PM.

3. Emissions Increases

The differences between the baseline actual emissions and projected actual emissions are compared to the significant emissions increase levels.

Pollutant	Baseline Actual Emissions (ton/year)	Projected Actual Emissions (ton/year)	Emissions Increase (ton/year)	Significant Emissions Increase Levels (ton/year)
PM	0	58.2	+58.2	25
PM_{10}	0	65.7	+65.7	15
$PM_{2.5}$	0	59.6	+59.6	10
SO_2	0	0.8	+0.8	40
NO_x	0	98.7	+98.7	40
CO	0	120.0	+120.0	100
VOC	0	160.9	+160.9	40
CO_2e	0	171,947	+171,947	75,000

__Note:__ The emission rates listed above for particulate matter include estimates for fugitive emissions. For the remainder of this license, only readily quantifiable stack emissions will be addressed.

4. Classification

Since emissions increases exceed significant emissions increase levels, this NSR License is determined to be a major modification for PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC, and CO_2e under *Minor and Major Source Air Emission License Regulations,* 06-096 C.M.R. ch. 115. Woodland Pulp has submitted an application to incorporate the requirements of this NSR license into the facility's Part 70 air emission license.

II. BEST PRACTICAL TREATMENT (BPT)

A. Introduction

In order to receive a license, the applicant must control emissions from each unit to a level considered by the Department to represent Best Practical Treatment (BPT), as defined in 06-096 C.M.R. ch. 100. Separate control requirement categories exist for new and existing equipment as well as for those sources located in designated non-attainment areas.

BPT for new sources and modifications requires a demonstration that emissions are receiving Best Available Control Technology (BACT), as defined in 06-096 C.M.R. ch. 100. BACT is a top-down approach to selecting air emission controls considering economic, environmental, and energy impacts.

B. Nonattainment New Source Review

The proposed project results in a significant emission increase for NO_x and VOC, ground-level ozone precursor pollutants. Although Maine is classified as in attainment for ozone, the project is required to be reviewed under Nonattainment New Source Review (NNSR) due to Maine's inclusion in the Ozone Transport Region (OTR). NNSR requirements for ozone include obtaining offsets for each ton of pollutant increase (NO_x and VOC) as described in *Growth Offset Regulation,* 06-096 C.M.R. ch. 113 and applying Lowest Achievable Emission Rate (LAER) instead of BACT for these pollutants.

1. NO_x Waiver

Maine currently has an EPA approved NO_x waiver issued under section 182(f) of the Clean Air Act. The NO_x waiver exempts significant emission increases of NO_x from NNSR requirements. Instead, significant emission increases of NO_x are processed under the requirements of the Prevention of Significant Deterioration (PSD) program. PSD does not require offsets and BACT is applied instead of LAER.

2. LAER

This project must address VOC offsets and LAER. LAER for this project is addressed later in this license.

3. Emission Offset Credits

   a. Identification of Emission Offset Credits

   The proposed VOC emissions increase for this project is 160.9 tpy. Pursuant to the requirements of 06-096 C.M.R. ch. 113, an offset ratio of 1.15 has been applied resulting in an offset requirement of 185.0 tons.

   Woodland Pulp certified 100.3 tons of NO_x offset credits and 84.9 tons of VOC offset credits from the permanent shutdown of their "Chip n' Saw" facility in offset certification A-126-71-R-O, dated 6/12/18. The trading of NO_x emissions credits for VOC without the application of an additional ratio is allowed by 06-096 C.M.R. ch. 113, § 3.E.(1)(b) since reductions of NO_x emissions in Maine are just as effective at reducing ground-level ozone as reductions in VOC emissions.

   The 185.2 tons of offset credits certified in A-126-71-R-O shall be applied to this project to satisfy the offset requirement. By doing so, Woodland Pulp has satisfied the requirement to obtain and permanently retire 185.0 tons of emissions reduction credits to offset the VOC emission increase from the project.

   b. Interprecursor Trading

   In a letter to EPA dated June 14, 2018, the Department provided information demonstrating that either NO_x or VOC emission offset credits can be used to achieve the same potential ozone reductions for this project.

   All areas in Maine are currently designated as attainment/unclassifiable for the current 2015 Ozone National Ambient Air Quality Standard (NAAQS). A trajectory analysis was provided which showed that emissions from Maine do not significantly contribute to any areas which are classified as nonattainment and that neither reductions of NO_x or VOC will help reduce ozone levels in those areas. In addition, an analysis of monitoring performed in Maine demonstrate that areas of the state where ozone events have occurred are transitional, meaning the majority of the time the creation of ozone is neither limited by NO_x nor VOC. In such cases, reductions of NO_x emissions would be equally effective in limiting ozone creation as reductions in VOC. Therefore, using NO_x emission offset credits in lieu of VOC emission offset credits would result in the same potential reductions in ozone.

   EPA has stated to the Department that the written comments supplied by EPA on Woodland Pulp's draft license amendment are intended to fulfill the requirement in 06-096 C.M.R. ch. 113, § 3(E)(1)(b) for written notification of approval.

C. Tissue Machines

1. Project Description

Woodland Pulp is proposing to install and operate two new tissue machines, TM3 and TM4, and remove the emissions cap from the facility's two existing tissue machines, TM1 and TM2.

TM1 and TM2 are both 200-inch lightweight dry crepe (LDC) machines, each with a maximum production capacity of approximately 187.4 air-dried tons (ADT) of finished product per day of bath, towel, and napkin grade tissue products, with production volume varying depending on the final grade mix of products to be manufactured. Each machine utilizes a yankee dryer, which includes a large steam-heated drum and a hood in which hot air produced by direct-fired natural gas burners with a heat input capacity of approximately 50 MMBtu/hr (total per machine) impinges on the paper sheet. The tissue is separated from the drum by a doctor blade. The yankee drum is heated by steam provided by the existing steam plant. TM1 and TM2 are co-located adjacent to the machine building that formerly housed the No. 4 Paper Machine. A tissue winder/combiner now occupies the former No. 4 Paper Machine building.

Similar to TM1 and TM2, TM4 will be a LDC machine with a maximum production capacity of 187.4 ADT/day of finished product. TM4 will also have a yankee dryer which operates in the same manner as described above for the yankee dryers on TM1 and TM2. The hot air in the hood of the yankee dryer for TM4 will be heated by direct-fired natural gas burners with a combined maximum heat input capacity of 50 MMBtu/hr, and the drum will be heated by steam from the existing steam plant. TM4 will be similar in size and production capacity to TM1 and TM2.

TM3 will be a through-air-dried (TAD) machine with a maximum production capacity of approximately 276 ADT/day. In addition to utilizing a yankee dryer as described above, TM3 will also utilize a through-air dryer. The yankee dryer and through-air dryer on TM3 will both be heated by direct-fired natural gas burners with a combined maximum heat input capacity of approximately 183 MMBtu/hr.

2. Exhaust Points

Each tissue machine has multiple exhaust points to the atmosphere as well as fugitive emissions. The primary exhaust points from each tissue machine include wet end exhausts, the dust stack, and the yankee hood/through-air-dryer stack.

There are no reliably quantifiable PM or combustion pollutants emitted from the wet end exhausts. However, VOC emission may occur at these locations.

The dust stacks collect and exhaust emissions in areas where PM emissions are expected to be highest, including the creping doctor blade at the yankee drum and the reel.

The yankee hood and through-air-dryer (TAD) stacks collect and exhaust emissions of products of combustion and some additional PM from the gas-fired yankee dryer hoods and through-air-dryer.

3. Best Available Control Technology (BACT)

The following is a summary of the BACT determination for the Tissue Machines, by pollutant.

a. Particulate Matter: $PM/PM_{10}/PM_{2.5}$

PM emissions from the Tissue Machines are attributable to both the combustion and process sides of each unit. PM emissions from natural gas-fired sources are generally minimal and are comprised of filterable and condensable PM generated both from the carryover of noncombustible trace constituents in the fuel and as products of incomplete combustion. PM emissions from the process side of each unit are generated by the tissue making process itself as dust particles are freed from the paper web during drying and as the dried sheet is removed from the yankee cylinder by the doctor blade. Potential control technologies for PM emissions include add-on pollution control equipment such as fabric filters (baghouses), electrostatic precipitators (ESP), wet scrubbers, cyclones, combustion of clean fuels, and good combustion practices.

Mechanical separators include cyclonic and inertial separators. In a cyclone, centrifugal force separates larger PM from the gas stream. The exhaust gas enters a cylindrical chamber on a tangential path and is forced along the outside wall of the chamber at a high velocity, causing the PM to impact collectors on the outer wall of the unit and fall into a hopper for collection. Mechanical separators have typical removal efficiencies of 40 to 90 percent for PM_{10} and zero to 40 percent for $PM_{2.5}$. The use of cyclones is considered a technically and economically feasible option for the control of PM emissions from the Tissue Machines. Almost all of the projects found in the RBLC review employed dust collection and cyclone systems that are integral to the tissue machine itself. TM1 and TM2 include cyclone systems that are built in to the design of the machine itself. Similarly, TM3 and TM4 will have these built-in, integral cyclone systems. Therefore, the BACT analysis for all other particulate matter control technologies are based on emissions after the cyclones.

Fabric filters, commonly referred to as baghouses, use fabric filter media to remove PM (filterable) from the exhaust gases of air emission sources. Baghouses consist of a matrix of fabric bags surrounded by an outer shell. Air enters the bags at the bottom and passes through the fabric filter media of the bags. Particles too large to fit through the pore spaces in the fabric are trapped on the inside of the bag, while the exhaust gas continues on to the stack. The bags are then emptied into a hopper located at the bottom of the unit at preset intervals. Baghouses can achieve filterable PM removal efficiencies of up to 99.9 percent. Due to the high moisture loading of the Tissue Machines' exhaust and ventilation streams, baghouses would be blinded and not effective in this application; therefore, baghouses are considered technologically infeasible for this application.

ESPs remove filterable PM from a gas stream through the use of electric fields. Exhaust gas entering the ESP is ionized, which negatively charges the filterable PM and causes it to be attracted to and collected on positively charged plates. These plates are then rapped mechanically to dislodge the PM at preset intervals into a hopper for appropriate collection and disposal. Collection efficiency is affected by several factors, including particle resistivity, gas temperature, chemical composition (of both the particles and the gas), and particle size distribution. Removal efficiencies for ESPs are 99+ percent of total filterable PM and up to 98 percent for PM in the range of 0-5 microns. Wet ESPs are specifically designed to collect PM from wet air streams and are thus considered technically feasible. However, it has been estimated that it would cost an additional $1,677,450 per tissue machine to install a wet ESP. This change would result in a reduction of PM emissions, above what cyclones can remove, of 0.22 tpy, resulting in a cost of $765,240/ton of PM controlled. The high capital and operating costs associated with wet ESPs make this option economically unjustifiable. A review of similar projects from the US EPA's RACT-BACT-LAER Clearinghouse (RBLC) did not indicate that any tissue machines currently employ the use of a wet ESP.

Wet scrubbers remove PM from gas streams primarily through impaction and, to a lesser extent, other mechanisms such as interception and diffusion. A scrubbing liquid (typically water) is sprayed countercurrent to the exhaust gas stream. Contact between the larger scrubbing liquid droplets and the suspended particulates removes the PM from the gas stream. Entrained liquid droplets then pass through a mist eliminator (coalescing filter) which causes the droplets to become heavier and fall out of the exhaust stream. Wet scrubbers typically have removal efficiencies of 90 to 99 percent for emissions of PM_{10} and significantly lower efficiencies for $PM_{2.5}$ (as low as 50 percent for spray tower scrubbers). High-efficiency scrubbers such as venturi scrubbers can be used to achieve greater removal efficiencies of $PM_{2.5}$ due to the high velocities and pressure drops at which they operate. Although considered technically feasible, the higher capital and operating costs associated with wet scrubbers as compared to cyclones make this option economically unjustifiable. A review of the RBLC did identify one tissue machine employing the use of a wet scrubber. However, the air permit application for that tissue machine indicated the wet scrubber is needed for industrial hygiene and is not cost effective.

It has been estimated that it would cost an additional $223,660 per tissue machine to install wet scrubbers. This change would result in a reduction of PM emissions, above what cyclones can remove, of 0.22 tpy, resulting in a cost of $32,410/ton of PM controlled. The use of wet scrubbers on the tissue machines is determined not to be economically justifiable.

The combustion of clean fuels to minimize PM emissions is accomplished by burning fuels with a minimal amount of impurities in conjunction with good combustion practices. Good combustion practices include keeping the air-to-fuel ratio at the manufacturer's specified setting and having the proper air and fuel pressures at the burner. The facility has proposed to burn natural gas in the tissue machine dryers which has an inherently low PM content compared to other fuel alternatives.

The Department finds the use of a dust collection system to capture PM emissions and minimize fugitive emissions from the dry end of the Tissue Machines, routing the wet dust through cyclone separators, and the following emission limits on the dryer outlets and dust stacks to represent BACT for particulate matter emissions from the Tissue Machines:

Pollutant	Unit	Emission Limit
PM	TM1, TM2, and TM4 [each]	1.29 lb/hr
	TM3	1.90 lb/hr
PM_{10}	TM1, TM2, and TM4 [each]	2.44 lb/hr
	TM3	3.59 lb/hr
$PM_{2.5}$	TM1, TM2, and TM4 [each]	2.38 lb/hr
	TM3	3.51 lb/hr

Due to the wide variety of products that can be made on the tissue machines, rate-based emission limits in units of lb/ADT are not indicative of optimal operation of control equipment. Different grades of tissue can impact emissions of particulate matter in various ways and in a non-linear manner. Therefore, particulate matter emission limits in units of lb/hr only were determined to be most appropriate for this equipment.

Compliance with the PM lb/hr emission limits for TM1, TM2, and TM4 shall be demonstrated by conducting performance testing on the yankee hood stack and dust stack (both stacks tested simultaneously) on either TM1 or TM2 by July 27, 2021, in accordance with 40 C.F.R. Part 60, Appendix A, Method 5 or other method as approved by the Department.

Compliance with the PM lb/hr emission limit for TM3 shall be demonstrated by conducting performance testing on the TAD stack and dust stack (both stacks tested simultaneously) within 180 days of startup of TM3 in accordance with 40 C.F.R. Part 60, Appendix A, Method 5 or other method as approved by the Department.

To date, EPA has not published a test method to measure condensable particulate matter from a saturated wet plume such as from the tissue machines. Therefore, compliance with the emission limits listed above for PM_{10} and $PM_{2.5}$ shall be demonstrated by the following work practice standards to ensure the control equipment is properly maintained and operated.

(1) Monthly inspections of the wet dust collection system and cyclone separator on each tissue machine; and
(2) Recordkeeping of all maintenance, malfunctions, inspections, and downtime of the wet dust collection system and cyclone separators.

Records of these work practice standards shall be maintained and are considered periodic monitors.

b. Sulfur Dioxide: SO_2

Emissions of SO_2 from tissue machines are attributable to the oxidation of sulfur compounds contained in the fuel used to generate heat in the dryers. Pollution control options to reduce SO_2 emissions include flue gas desulfurization by means of wet scrubbing and firing fuels with an inherently low sulfur content, such as natural gas.

Flue gas desulfurization by means of wet scrubbing works by injecting a caustic solution, such as limestone or lime, into a scrubber unit to react with the SO_2 in the flue gas to form a precipitate and either carbon dioxide or water. Flue gas desulfurization by means of wet scrubbing can have control efficiencies upwards of 90 percent. For a low-sulfur fuel such as natural gas, the installation costs, annual operating and maintenance costs, costs for the caustic solution used in the scrubber, and the increased use of energy make this option technologically and economically infeasible.

The Department finds the use of clean fuels such as natural gas, which inherently has a low sulfur content, and SO_2 emission limits of 0.03 lb/hr each from TM1, TM2, and TM4 and 0.11 lb/hr from TM3 to represent BACT for SO_2 emissions from the Tissue Machines. Compliance shall be demonstrated by monthly records of the amount of natural gas fired in each tissue machine.

c. Nitrogen Oxides: NO_x

Emissions of NO_x from the Tissue Machines are attributable to the combustion of natural gas in the yankee hood and TAD burners. NO_x from the combustion process are generated through one of three mechanisms: fuel NO_x, thermal NO_x, and prompt NO_x. Fuel NO_x is produced by the oxidation of nitrogen in the fuel source, with low nitrogen content fuels such as distillate fuel and natural gas producing less NO_x than fuels with higher levels of fuel-bound nitrogen. Thermal NO_x forms in the high temperature area of the combustor and increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel needed to consume all the available oxygen, also known as the equivalence ratio. The lower this ratio is, the lower the flame temperature; thus, by maintaining a low fuel ratio (lean combustion), the potential for NO_x formation can be reduced. In most modern burner designs, the high temperature combustion gases are cooled with dilution air. The sooner this cooling occurs, the lower the formation of thermal NO_x. Prompt NO_x forms from the oxidation of hydrocarbon radicals near the combustion flame; this produces an insignificant amount of NO_x.

Control of NO_x emissions can be accomplished through one of three methods: the use of add-on controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR), the use of combustion control techniques, such as low excess air firing, burner modifications, water/steam injection, and flue gas recirculation (FGR), and the combustion of clean fuel, such as distillate fuel or natural gas.

Add-on pollution control technology for the reduction of NO_x include SCR, where NO_x is reduced with the aid of a catalyst into diatomic nitrogen and water using a reductant, and SNCR, where either ammonia or urea is injected into the firebox of a combustion unit where the flue gas is between 1,400 and 2,000 degrees Fahrenheit to react with the NO_x produced by combustion to create diatomic nitrogen, carbon dioxide, and water. SCR and SNCR are primarily used on large industrial and utility boilers. It has been estimated that it would cost an additional $250,000 per tissue machine to install a SCR. This change would result in a reduction of annual NO_x emissions of 4.3 tpy per machine, resulting in a cost of $30,700/ton of NO_x controlled. It has been estimated that it would cost an additional $85,000 per tissue machine to install a SNCR. This change would result in a reduction of annual NO_x emissions of 8.6 tpy per machine, resulting in a cost of $15,100/ton of NO_x controlled. The use of SCR or SNCR on the tissue machines is determined not to be economically feasible. Additionally, the use of controls which utilize injection of ammonia or urea could adversely affect the quality of the product should the reagent be absorbed into the tissue during the manufacturing process. A review of similar projects from the RBLC did not indicate that any tissue or paper machines used an add-on control technology for NO_x emissions.

Combustion controls for control of NO_x emissions include low excess air firing, FGR, low NO_x burners (LNB), and ultra-low NO_x burners (ULNB). Low excess air firing involves limiting the net excess air flow to the combustion chamber to under 2%. FGR is a system where a portion of the flue gas is recirculated back into the main combustion chamber; this helps to decrease the formation of thermal NO_x by lowering the peak flame temperature and reducing the oxygen concentration surrounding the flame zone. FGR systems require moderately high capital costs due to the ductwork needed to span from the burner outlet to the combustion air duct and the operating costs associated with the energy requirements of recirculation fans. Additionally, FGR systems can affect heat transfer and system pressures. A review of the RBLC did not identify any tissue or paper machines using low excess air firing or FGR to control NO_x emissions from dryer burners.

LNBs reduce NO_x by causing combustion to occur in stages; this delays the combustion process and results in a cooler flame that suppresses thermal NO_x formation. Similar to FGR systems, LNBs also require moderately high capital costs for the combustion technology. LNBs have been observed to have NO_x emission reductions of 40 to 85 percent relative to uncontrolled emission levels. LNBs are considered technically and economically feasible for control of NO_x emissions from the dryer burners.

ULNBs employ staged combustion similar to LNBs while also allowing for the injection of flue gas at the burner. This allows the flue gas and fuel gas to mix prior to combustion which serves to reduce flame temperature substantially and greatly suppress the formation of thermal NOx. ULNBs are capable of reducing NO_x emissions by 60 to 90 percent relative to uncontrolled emission levels. ULNBs represent the greatest NO_x emissions reduction potential, but also represent the highest capital cost of all the combustion control options. It has been estimated that it would cost an additional $61,275 per tissue machine to install ULNBs instead of LNBs. This change would result in a reduction of annual NO_x emissions of 3.8 tpy per machine, resulting in a cost of $16,125/ton of NO_x controlled. Although technically feasible, the higher costs and minimal additional emission reductions of using ULNBs instead of LNBs makes their use economically unjustifiable.

The final method for controlling NO_x from combustion sources is the combustion of fuel with less fuel bound nitrogen. Woodland Pulp proposes to burn natural gas in the dryers on the Tissue Machine which inherently has a low nitrogen content.

The Department finds the use of LNBs on TM1, TM2, TM3, and TM4, firing natural gas, and emission limits of 4.52 lb/hr for TM1, TM2, and TM4 (each) and 8.97 lb/hr for TM3 to represent BACT for NO_x emissions from the tissue machines.

Compliance with the NO_x lb/hr emission limits for TM1 and TM2 shall be demonstrated by conducting performance testing on the yankee hood stack on either TM1 or TM2 by July 27, 2021 in accordance with 40 C.F.R. Part 60, Appendix A, Method 7 or other method as approved by the Department.

Compliance with the NO_x lb/hr emission limit for TM3 shall be demonstrated by conducting performance testing on the TAD stack within 180 days of startup of TM3 in accordance with 40 C.F.R. Part 60, Appendix A, Method 7 or other method as approved by the Department.

Compliance with the NO_x lb/hr emission limit for TM4 shall be demonstrated by conducting performance testing on the yankee hood stack within 180 days of startup in accordance with 40 C.F.R. Part 60, Appendix A, Method 7 or other method as approved by the Department.

In addition, within 180 days of conducting NO_x performance testing for lb/hr limits on either TM1 or TM2, Woodland Pulp shall propose, and apply to amend their license to incorporate, NO_x limits in units of ppm for TM1 and TM2. Woodland Pulp shall propose, and apply to amend their license to incorporate, NO_x limits in units of ppm for TM3 and TM4 (each) within one year of each individual machine's startup.

d. Carbon Monoxide: CO

Emissions of CO from the Tissue Machines are attributable to the incomplete combustion of organic compounds contained in the natural gas fired in the yankee hood burners and TAD burners. Potential technologies for the control of CO emissions from the Tissue Machines include add-on controls, such as oxidation catalysts, and combustion control techniques, such as good combustion practices and ULNBs.

Add-on pollution control technology for the reduction of CO from combustion sources primarily includes oxidation catalysts, where CO is oxidized with the aid of a catalyst into carbon dioxide. Catalytic oxidation can achieve upwards of 90% removal efficiency of CO. Oxidation catalysts are commonly used on large natural gas-fired internal combustion sources such as stationary engines and stationary combustion turbines to reduce CO and VOC emissions, but their use has recently emerged on newer boilers. A review of the RBLC, however, did not indicate that any paper or tissue machines use oxidation catalysts for the control of CO emissions. This fact, in addition to the cost of installation, associated annual operating and maintenance costs, and increased energy consumption from use of an oxidation catalyst, make this option economically infeasible.

Potential combustion control techniques for the control of CO emissions from fuel combustion include good combustion practices and the use of ULNBs. ULNBs have historically been associated with higher CO emissions due to the limited oxygen available for complete combustion after the introduction of flue gas into the burner. Newer ULNB technology, however, uses sophisticated burner management control systems to maintain optimal fuel-to-air ratios; this allows newer ULNBs to reduce both NO_x and CO emissions considerably. These newer burners can reduce CO emissions between 65 and 85 percent compared to the burners they replace. The high capital costs associated with installing ULNBs for the control of CO alone, however, makes this option economically and technologically infeasible.

The Department finds the use of good combustion practices and CO emission limits of 4.12 lb/hr for TM1, TM2, and TM4 and 15.07 lb/hr for TM3 to represent BACT for CO emissions from the Tissue Machines.

Compliance with the CO lb/hr emission limits for TM1 and TM2 shall be demonstrated by conducting performance testing on the yankee hood stack on either TM1 or TM2 by July 27, 2021, in accordance with 40 C.F.R. Part 60, Appendix A, Method 10 or other method as approved by the Department.

Compliance with the CO lb/hr emission limit for TM3 shall be demonstrated by conducting performance testing on the TAD stack within 180 days of startup of TM3 in accordance with 40 C.F.R. Part 60, Appendix A, Method 10 or other method as approved by the Department.

Compliance with the CO lb/hr emission limit for TM4 shall be demonstrated by conducting performance testing on the yankee hood stack within 180 days of startup in accordance with 40 C.F.R. Part 60, Appendix A, Method 10 or other method as approved by the Department.

In addition, within 180 days of conducting CO performance testing for lb/hr limits on either TM1 or TM2, Woodland Pulp shall propose, and apply to amend their license to incorporate, CO limits in units of ppm for TM1 and TM2. Woodland Pulp shall propose, and apply to amend their license to incorporate, CO limits in units of ppm for TM3 and TM4 (each) within one year of each individual machine's startup.

e. Greenhouse Gas: GHG

GHG emissions from the Tissue Machines are attributable to the hot air dryers, which emit carbon dioxide (CO_2) as a product of the combustion process. No GHG emissions control technologies can be identified that may be considered technically feasible for application to these units. The Department finds the use of natural gas, a clean-burning fuel, to limit GHG emissions to represent BACT for GHG emissions from the Tissue Machines. Compliance shall be demonstrated by the recordkeeping requirements contained in this license.

f. Visible Emissions

BACT for visible emissions from the Tissue Machines shall be the following:

Visible emissions from each Tissue Machine and its associated fuel-burning equipment shall not exceed 10% opacity on a six-minute block average basis.

4. Lowest Achievable Emission Rate (LAER)

The following is a summary of the LAER determination for VOC for the Tissue Machines.

VOC emissions from the Tissue Machines are attributable to many different sources. Small amounts of VOC are present in the water carrying the pulp to the Tissue Machines and dryers and may be released as the water is removed from the sheet. The most often detected compound from this source is methanol, a byproduct of the chemical and mechanical pulping and bleaching processes. VOC are also present in papermaking additives (defoamers, slimicides, retention aids, wet strength agents, wire and felt cleaners, etc.) and may be released in the papermaking process. On tissue machines with direct-fired dryers, VOC are also emitted from the combustion of fuel.

A significant emissions increase of a nonattainment pollutant is required to meet the Lowest Achievable Emission Rate (LAER). LAER is defined in 06-096 C.M.R. ch. 100 to mean "*the most stringent emission limitation which is contained in the implementation plan of any State for that class or category of source, unless the owner or operator of the proposed source demonstrates that those limitations are not achievable; or the most stringent emission limitation which is achieved in practice by that class or category of source, whichever is more stringent. In no event may LAER result in emissions of any pollutant in excess of those standards and limitations promulgated pursuant to Section 111 or 112 of the United States Clean Air Act as amended, or any emission standard established by the Department.*"

A review of the RBLC identified a wide variety of VOC limitations on tissue machines, with some permits containing no VOC emission limitations whatsoever. None of the tissue machines identified employed any type of control technology for VOC. The most stringent VOC emission rate identified was for Irving Consumer Products (Irving) in Macon, GA, at 0.062 lb/ADT; however, achieving this emission rate would not be feasible for Woodland Pulp. The Irving emission rate appears to be based on a paper machine emission factor of 0.069 lb/ADT, published in Table 4.16 of NCASI TB 884, which is not an appropriate factor for tissue machines, which require a different set of additives and chemicals to create the special properties of tissue. The next most stringent emission rates identified were 0.58 lb/ADT and 0.75 lb/ADT for Gorham Paper and Tissue and Catalyst Paper Operations, respectively. These values are only technically achievable if the facility completely changes the product portfolio it currently produces and intends to produce on the Tissue Machines. Including these processes in the LAER analysis would involve fundamentally redefining the project. BACT and LAER do not require source redefinition as their intent is not to regulate the applicant's purpose or objective for the proposed facility.

The next most stringent VOC limit for tissue machine process emissions is 1.01 lb/ADT at Sofidel American in Circleville, OH. This limit is achievable based on actual, historical chemical/additive use for TM1 and TM2. Woodland Pulp has proposed a more stringent target limit on process VOC emission of 1.00 lb/ADT. This limit assumes 100% of the VOC in chemicals/additives is volatilized. This is a highly conservative approach to estimating VOC emissions from tissue machines since many paper/tissue machine additives will react with the web substrate, limiting actual VOC emissions to the unreacted portion of VOC only. In addition, some of the VOC retained in the white water recycle loop may be controlled by the wastewater treatment plant, and some of the VOC will volatilize in the drying sections of the machine where the paper web is exposed to higher temperatures.

VOC emitted from combustion sources, such as tissue machine dryers, are the result of incomplete combustion of fuel in the form of unburned hydrocarbons. VOC emissions from combustion sources are controlled through control equipment, such as oxidation catalysts, and good combustion controls. A review of the RBLC did not identify any tissue or paper machines using control equipment for the control of VOC emissions from the dryers. Therefore, the Department has determined the use of good combustion controls represents LAER for VOC emissions from the combustion of natural gas in the Tissue Machine dryers.

The Department finds good combustion controls and the following emission limits to represent LAER for VOC emissions from the Tissue Machines:

a. A process VOC limit of 1.00 lb/ADT for each Tissue Machine;
b. A combustion VOC limit of 0.27 lb/hr each for TM1, TM2, and TM4; and
c. A combustion VOC limit of 0.99 lb/hr for TM3.

5. Emission Limits

The BACT emission limits for the four Tissue Machines and associated dryers firing natural gas are the following:

Unit	PM lb/hr	PM_{10} lb/hr	$PM_{2.5}$ lb/hr	SO_2 lb/hr	NO_x lb/hr	CO lb/hr
TM1	1.29	2.44	2.38	0.03	4.52	4.12
TM2	1.29	2.44	2.38	0.03	4.52	4.12
TM3	1.90	3.59	3.51	0.11	8.97	15.07
TM4	1.29	2.44	2.38	0.03	4.52	4.12

The LAER emission limits for the four Tissue Machines and associated dryers firing natural gas are the following:

Unit	VOC (Combustion only) lb/hr	VOC (Process only) lb/ADT
TM1	0.27	1.00
TM2	0.27	1.00
TM3	0.99	1.00
TM4	0.27	1.00

Emissions of VOC from combustion of natural gas are well known and documented. The combustion VOC emission limits listed above will be met provided the burners are operating correctly. Thus, compliance with the combustion VOC emission limits shall be demonstrated by compliance with the NO_x emission limits contained in this license.

Demonstrating compliance with the process VOC emission limits through performance testing is technically difficult as some VOC emissions are fugitive and do not exit through stacks. Woodland Pulp has proposed demonstrating compliance with the process VOC emission limits for the tissue machines by recordkeeping, including tracking the VOC content and volume of chemical additives used on each tissue machine. Process VOC emissions shall be assumed to be the total of all VOC contained in the chemical additives used on each machine. This method estimates emissions conservatively high as it does not take credit for any VOC that remains in the product or VOC that remains with the wastewater and controlled by the wastewater treatment plant. Therefore, compliance with the process VOC emission limits shall be demonstrated by the following recordkeeping:

(1) Monthly records of the amount of each VOC-containing chemical additive used on each machine;
(2) Records of the VOC content for each chemical additive used;

(3) Monthly records of the amount (ADT) of finished tissue product produced on each machine; and
(4) Monthly calculations demonstrating compliance with the process VOC emission limits.

These records are considered periodic monitors.

6. Periodic Monitoring

a. Periodic monitoring for the control equipment on the Tissue Machines shall include the following, as applicable:

(1) Monthly inspections of the wet dust collection system, venturi scrubber, and cyclone separator on each tissue machine;
(2) Recordkeeping to document all maintenance, malfunctions, inspections, and downtime of the wet dust collection systems, venturi scrubbers, and cyclone separators; and
(3) Monitoring and recordkeeping of the flow rate through and pressure drop across each venturi scrubber at least once per shift.

b. Periodic monitoring for all four Tissue Machines shall include the following:

(1) Monthly records of the amount of each VOC-containing chemical/additive used on each machine;
(2) Records of the amount of VOC in each chemical additive used;
(3) Monthly records of the amount (ADT) of finished tissue product produced on each machine;
(4) Monthly calculations demonstrating compliance with the process VOC emission limits; and
(5) Monthly records of fuel use for each tissue machine.

The records above shall be used to demonstrate compliance with the LAER limit of 1.00 lb/ADT of process VOC emissions. Compliance with the combustion VOC emission limits shall be based on fuel use records and the EPA emission factor for natural gas combustion of 5.5 lb VOC per million standard cubic feet.

7. Regulatory Applicability

a. Federal Regulations

(1) New Source Performance Standards

New Source Performance Standards (NSPS) require new, modified, or reconstructed individual industrial or source categories to control emissions to the level achievable by the best-demonstrated technology. Sources subject to an NSPS are also subject to the general provisions established in *General Provisions*, 40 C.F.R. Part 60, Subpart A.

There are no potentially applicable NSPS that could apply to the new Tissue Machines or their natural gas-fired dryers.

(2) National Emission Standards for Hazardous Air Pollutants

National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations establish emission standards for air pollutants not covered by the National Ambient Air Quality Standards (NAAQS), primarily hazardous air pollutants (HAP). The standards for source categories establish requirements for the installation of the maximum available control technology (MACT), as determined by the United States Environmental Protection Agency (EPA).

The Tissue Machines at Woodland Pulp are not subject to *NESHAP: Paper and Other Web Coating*, 40 C.F.R. Part 63, Subpart JJJJ. EPA has determined that 40 C.F.R. Part 63, Subpart JJJJ does not apply to size presses or on-machine coaters used in the paper industry. Since the Tissue Machines do not have off-machine coaters, they are not subject to this subpart.

The Tissue Machines at Woodland Pulp are not subject to *NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*, 40 C.F.R. Part 63, Subpart DDDDD. The burners on the Tissue Machine dryers produce heat/exhaust that comes into direct contact with the product; therefore, the dryers are not considered process heaters as defined in 40 C.F.R. Part 63, subpart DDDDD.

b. State Regulations

(1) *Visible Emissions Regulation*, 06-096 C.M.R. ch. 101

The Tissue Machines are subject to *Visible Emissions Regulation*, 06-096 C.M.R. ch. 101. This chapter establishes opacity limitations for emissions from several categories of air contaminant sources. The Tissue Machines are subject to Section 2(B)(3)(d) of the chapter, which limits visible emissions from any general process source not specifically listed in 06-096 C.M.R. ch. 101 to 20% opacity on a six-minute block average basis, except for no more than one six-minute block average in a one-hour period. This limit shall be streamlined to the more stringent BACT limit of 10% opacity on a six-minute block average basis.

(2) *Fuel Burning Equipment Particulate Emission Standard*, 06-096 C.M.R. ch. 103

The Tissue Machines are not subject to *Fuel Burning Equipment Particulate Emission Standard*, 06-096 C.M.R. ch. 103, which applies to all fuel burning equipment that has a rated heat input capacity of 3 MMBtu/hr or greater. The natural gas-fired yankee hood and through-air dryers on TMs 1-4 have rated heat input capacities greater than 3 MMBtu/hr, but do not meet the definition of "fuel burning equipment" as defined in 06-096 C.M.R. ch. 100; therefore, the dryers are not subject to 06-096 C.M.R. ch. 103.

(3) *General Process Source Particulate Emission Standard*, 06-096 C.M.R. ch. 105

The Tissue Machines are subject to *General Process Source Particulate Emission Standard*, 06-096 C.M.R. ch. 105, which applies to any source except fuel-burning equipment, incinerators, mobile sources, open burning sources, and sources of fugitive dust, and establishes a limitation on the amount of particulate emissions allowed from the source determined on the basis of the size and rate at which the process operates.

The Tissue Machines have the potential to generate PM emissions, and are therefore subject to the applicable limitations in Table 105A of 06-096 C.M.R. ch. 105. Based on their maximum production rates of 187.4 ADT/day, TM1, TM2, and TM4 are each subject to a PM emission limit of 12.7 lb/hr. Based on its maximum production rate of 276 ADT/day TM3 is subject to a PM emission limit of 16.1 lb/hr. These limits are less stringent than the BACT limits for PM emissions from the Tissue Machines; therefore, the limits provided by 06-096 C.M.R. ch. 105 shall be streamlined to the units' BACT emission limits.

D. Additional Requirements

As part of their application, Woodland Pulp performed a refined modeling analysis to determine the facility's impact on ambient air quality. The facility was not able to demonstrate compliance with National Ambient Air Quality Standards (NAAQS) and Class I and Class II Increment Standards at the BACT emission rates listed above. In order to demonstrate compliance, Woodland Pulp has proposed additional controls and emission limits beyond what is considered BACT as outlined in this section. These requirements may be modified or removed through a license amendment that includes an updated ambient air quality analysis demonstrating compliance with NAAQS and Class I and II Increment Standards.

1. TM1, TM2, TM3, & TM4: Particulate Matter

To comply with NAAQS and Class I and II Increment Standards for particulate matter from the tissue machines, Woodland Pulp proposes the following additional requirements:

a. The use of venturi scrubbers on the dust stacks for all four tissue machines;
b. Increasing the stack height of each of the yankee/through-air-dryer sections on TM1 and TM2 to at least 117.3 feet AGL;
c. Exhausting emissions from the yankee/through-air-dryer sections of TM3 and TM4 to separate stacks that are each at least 117.75 feet AGL;
d. Compliance with the following emission limits:

Pollutant	Unit	Emission Limit
PM	TM1, TM2, and TM4 [each]	0.84 lb/hr
	TM3	1.23 lb/hr
PM_{10}	TM1, TM2, and TM4 [each]	0.82 lb/hr
	TM3	1.20 lb/hr
$PM_{2.5}$	TM1, TM2, and TM4 [each]	0.81 lb/hr
	TM3	1.19 lb/hr

The Department has determined that inclusion of the additional requirements listed above for particulate matter emissions from the tissue machines are appropriate for demonstrating compliance with NAAQS and Class I and II Increment Standards.

Compliance with the PM emission limit shall be demonstrated by conducting performance testing in accordance with 40 C.F.R. Part 60, Appendix A, Method 5 or other method as approved by the Department.

To date, EPA has not published a test method capable of measuring condensable particulate matter from a saturated wet plume such as from the tissue machines. Therefore, compliance with the emission limits listed above for PM_{10} and $PM_{2.5}$ shall be demonstrated by the following work practice standards to ensure the control equipment is properly maintained and operated:

(1) Monthly inspections of the wet dust collection system and cyclone separator on each tissue machine; and
(2) Recordkeeping of all maintenance, malfunctions, inspections, and downtime of the wet dust collection system and cyclone separators.

Records of these work practice standards shall be maintained and are considered periodic monitors.

2. TM3 & TM4: NO_x

To comply with NAAQS and Class I and II Increment Standards for NO_x from the tissue machines, Woodland Pulp proposes the following additional requirements:

a. The use of ULNB on TM3 and TM4;

b. Compliance with the following emission limits:

Pollutant	Unit	Emission Limits
NO_x	TM3	5.74 lb/hr
	TM4	1.57 lb/hr

Compliance shall be demonstrated by conducting performance testing in accordance with 40 C.F.R. Part 60, Appendix A, Method 7 or other method as approved by the Department.

In addition, Woodland Pulp shall propose, and apply to amend their license to incorporate, NO_x limits in units of ppm for TM3 and TM4 (each) within one year of each individual machine's startup.

The Department has determined that inclusion of the additional requirements listed above for NO_x emissions from TM3 and TM4 are appropriate for demonstrating compliance with NAAQS and Class I and II Increment Standards.

3. Existing Equipment: $PM_{2.5}$

$PM_{2.5}$ has not previously been addressed in Woodland Pulp's license. To comply with NAAQS and Class I and II Increment Standards, Woodland Pulp has proposed incorporating the following new $PM_{2.5}$ emission limits into their license:

Pollutant	Unit	Emission Limit
$PM_{2.5}$	#9 Power Boiler	84.4 lb/hr[1]
		76.0 lb/hr[2]
	Smelt Dissolving Tank	10.0 lb/hr
	Lime Kiln	20.8 lb/hr[3]
		15.0 lb/hr[4]

[1] When firing #6 fuel oil in combination with other fuels.
[2] When firing natural gas or propane in combination with other fuels.
[3] When firing #6 fuel oil.
[4] When firing natural gas or propane.

The Department has determined that inclusion of the additional requirements listed above for $PM_{2.5}$ emissions from #9 Power Boiler, the Smelt Dissolving Tank, and the Lime Kiln are appropriate for demonstrating compliance with NAAQS and Class I and II Increment Standards.

4. Existing Equipment: SO_2

Woodland Pulp's current air emission license allows them to demonstrate compliance with SO_2 emission limits using a combined emission limit for #3 Recovery Boiler and #9 Power Boiler for up to 300 hours per calendar year. To comply with NAAQS and Class I and II Increment Standards, Woodland Pulp has proposed lowering the existing combined SO_2 emission limit for #3 Recovery Boiler and #9 Power Boiler from 793 lb/hr (based on a 3-hour block average) to 600 lb/hr (based on a 3-hour block average) when firing #6 fuel oil in combination with other fuels or 559 lb/hr (based on a 3-hour block average) when firing natural gas or propane in combination with other fuels.

The Department has determined that the lowering of the combined SO_2 emission limits for #3 Recovery boiler and #9 Power Boiler as described above are appropriate for demonstrating compliance with NAAQS and Class I and II Increment Standards.

E. Incorporation into the Part 70 Air Emission License

The requirements in this 06-096 C.M.R. ch. 115 New Source Review license shall apply to the facility as specified in the Order section of this license. Per *Part 70 Air Emission License Regulations*, 06-096 C.M.R. ch. 140 § 1(C)(8), for a modification at the facility that has undergone NSR requirements or been processed through 06-096 C.M.R. ch. 115, the source must apply for an amendment to their Part 70 license within one year of commencing the proposed operations, as provided in 40 C.F.R. Part 70.5. Woodland Pulp submitted an application to incorporate the requirements of this NSR License into their Part 70 License on May 15, 2018.

F. Annual Emissions

1. Emission Totals

For annual fee purposes, the following represents the annualized total of licensed emission limits applicable to Woodland Pulp for the emission units listed. The listed emission units at Woodland Pulp shall be restricted to the following annual emissions, based on a 12-month rolling total:

Total Licensed Annual Emissions for the Facility[1]
Tons/year
(used to calculate the annual license fee[2])

	PM	PM_{10}	SO_2	NO_x	CO	VOC	TRS
Tissue Machines[4]	25.3	47.8	0.8	98.7	120.0	160.9	---
No. 9 Power Boiler	355.0	355.0	676.0	780.0	5,008.0	130.0	---
#3 Recovery Boiler	178.2	178.2	1,567.0	601.0	1,966.0	176.0	---
Smelt Dissolving Tank	50.0	50.0	---	---	---	---	13.6
Lime Kiln	87.0	87.0	35.0	175.0	1,750.0	---	---
Package Boiler	56.0	56.0	9.9	5.6	1.4	0.1	---
NCG Incinerator	8.4	8.4	12.7	39.6	2.8	0.2	---
Natural Gas Heater	0.7	0.7	---	1.3	1.1	0.1	---
Total	**760.6**	**783.1**	**2,301.4**	**1,178.0[3]**	**8,849.3**	**467.3**	**13.6**

1. Emission limits in the table do not include insignificant activities and process units (e.g. the woodyard) with no licensed emission limits, and do not include emergency engines whose possible emissions provide little or no noticeable contribution to the totals represented in this table.
2. PM_{10}, CO, and TRS are not used in the calculation of the annual fee but are included in this table for completeness.
3. Note that the total NOx limit for the mill is less than total allowable emissions from individual units. Woodland Pulp may emit up to each required limit for any one individual unit, provided that the total of all units does not exceed the mill wide total of 1,178.0 ton/year on a 12-month rolling total basis. See Condition (17) of Air Emission License A-215-70-I-R/A, issued November 18, 2011.
4. PM, PM_{10}, and NO_x emissions from the tissue machines are calculated based on BACT emission limits and without fugitive components.

2. Greenhouse Gases

Greenhouse gases are considered regulated pollutants as of January 2, 2011, through 'Tailoring' revisions made to EPA's *Approval and Promulgation of Implementation Plans,* 40 C.F.R. Part 52, Subpart A, § 52.21, *Prevention of Significant Deterioration of Air Quality* rule. Greenhouse gases, as defined in 06-096 C.M.R. ch. 100 are the aggregate group of the following gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. For licensing purposes, greenhouse gases (GHG) are calculated and reported as carbon dioxide equivalents (CO_2e).

The quantity of CO_2e emissions from this facility is greater than 100,000 tons per year, based on the following:
- the facility's fuel use and throughput limits;
- worst case emission factors from the following sources: U.S. EPA's AP-42, the Intergovernmental Panel on Climate Change (IPCC), and *Mandatory Greenhouse Gas Reporting,* 40 C.F.R. Part 98; and
- global warming potentials contained in 40 C.F.R. Part 98.

As defined in 06-096 C.M.R. ch. 100, any source emitting 100,000 tons/year or more of CO_2e is a major source for GHG. This license includes applicable requirements addressing GHG emissions from this source, as appropriate.

III. AMBIENT AIR QUALITY ANALYSIS

A. Overview

A refined modeling analysis was performed to show that emissions from Woodland Pulp, in conjunction with other sources, will not cause or contribute to violations of National Ambient Air Quality Standards (NAAQS) for SO_2, PM_{10}, $PM_{2.5}$, NO_2 or CO or to Class I or Class II increments for SO_2, PM_{10}, $PM_{2.5}$ or NO_2.

Based upon the magnitude of the SO_2, PM_{10} and NO_2 emissions increase and the distance from Woodland Pulp to the nearest Class I area, the US Fish & Wildlife Service (USFWS) have determined that a visibility assessment for plume blight is required for Moosehorn National Wildlife Refuge – Baring Unit (MNWR-Baring).

B. Model Inputs

The AERMOD-PRIME refined dispersion model was used to address NAAQS and increment impacts in all areas. The modeling analysis accounted for the potential of building wake and cavity effects on emissions from all modeled stacks that are below their calculated formula GEP stack heights.

All modeling was performed in accordance with all applicable requirements of the Maine Department of Environmental Protection, Bureau of Air Quality (MEDEP-BAQ) and the United States Environmental Protection Agency (USEPA). The most-recent regulatory version of the AERMOD-PRIME model and its associated processors were used to conduct the analyses.

A valid five-year hourly on-site meteorological database was used in the AERMOD-PRIME modeling analysis. The following parameters and their associated heights were collected at Woodland Pulp's meteorological monitoring site during the five-year period July 1, 1991 to June 30, 1996:

TABLE III-1: Meteorological Parameters and Collection Heights

Parameter	Sensor Heights
Wind Speed	10 & 76 meters
Wind Direction	10 & 76 meters
Standard Deviation of Wind Direction (Sigma Θ)	10 & 76 meters
Temperature	10 & 76 meters

When possible, hourly ISHD surface data collected at the Bangor International Airport NWS site were substituted for missing on-site surface data. All other missing data were interpolated or coded as missing, per USEPA guidance. In addition, hourly Bangor International Airport NWS data, from the same time period, were used to supplement the primary surface dataset for any required variables that were not explicitly collected on-site.

The surface meteorological data was combined with concurrent hourly cloud cover and upper-air data obtained from the Caribou National Weather Service (NWS). Missing cloud cover and/or upper-air data values were interpolated or coded as missing, per USEPA guidance.

All necessary representative micrometeorological surface variables for inclusion into AERMET (surface roughness, Bowen ratio and albedo) were calculated using the AERSURFACE utility program and from procedures recommended by USEPA.

Point-source parameters, used in the modeling for Woodland Pulp are listed in Table III-2.

TABLE III-2: Woodland Pulp Point Source Stack Parameters

Woodland Pulp Stacks	Stack Base Elevation (m)	Stack Height (m)	GEP Stack Height (m)	Stack Diameter (m)	UTM Easting NAD83 (m)	UTM Northing NAD83 (m)
PROPOSED/CURRENT						
#9 Power Boiler	37.06	68.58	128.45	3.66	625,698	5,001,618
#3 Recovery Boiler	35.88	83.82	130.05	2.90	625,747	5,001,644
#3 Smelt Tank	35.72	70.71	130.21	1.78	625,745	5,001,652
Lime Kiln	38.51	79.55	127.00	1.27	625,649	5,001,526
TM #1 – Yankee Hood	40.75	35.75	88.49	1.31	625,481	5,001,613
TM #1 – Dust Vent	40.75	29.66	88.49	1.60	625,480	5,001,640
TM #2 – Yankee Hood	40.75	35.75	70.97	1.31	625,432	5,001,594
TM #2 – Dust Vent	40.75	29.66	70.97	1.60	625,420	5,001,618
TM #3 – TAD	45.42	35.89	66.30	1.68	625,390	5,001,538
TM #3 – Dust Vent	45.42	29.79	66.30	1.68	625,370	5,001,549
TM #4 – Yankee Hood	45.42	35.89	66.30	1.31	625,330	5,001,497
TM #4 – Dust Vent	45.42	29.79	66.30	1.60	625,318	5,001,513
2010 BASELINE ($PM_{2.5}$ INCREMENT)						
#9 Power Boiler	37.06	68.58	128.45	3.66	625,698	5,001,618
#3 Recovery Boiler	35.88	83.82	130.05	2.90	625,747	5,001,644
#3 Smelt Tank	35.72	70.71	130.21	1.78	625,745	5,001,652
Lime Kiln	38.51	79.55	127.00	1.27	625,649	5,001,526
1987 BASELINE (NO_2 INCREMENT)						
#9 Power Boiler	37.06	46.33	92.26	3.66	625,698	5,001,618
Lime Kiln	38.51	49.07	127.00	1.49	625,649	5,001,526
1977 BASELINE (SO_2/PM_{10} INCREMENT)						
#9 Power Boiler	37.06	46.33	92.26	3.66	625,698	5,001,618
Lime Kiln	38.51	49.07	90.81	1.49	625,649	5,001,526
#8 Power Boiler	37.06	37.19	92.26	2.44	625,637	5,001,628

Emission parameters for Woodland Pulp NAAQS and increment modeling are listed in Table III-3. Emission parameters are based on two maximum license-allowed operating configurations: a combination of units firing oil and/or natural gas, and all units firing exclusively natural gas.

For the purpose of determining maximum predicted impacts, the following assumptions were used:

- NO_x emissions were assumed to convert to NO_2 using USEPA's Tier II Ambient Ratio Method (ARM2);
- all particulate emissions were conservatively assumed to convert to PM_{10}.

TABLE III-3: Stack Emission Parameters

Stacks	Averaging Periods	SO_2 (g/s)	PM_{10} (g/s)	PM2.5 (g/s)	NO_x (g/s)	CO (g/s)	Stack Temp (K)	Stack Velocity (m/s)
MAXIMUM LICENSE ALLOWED SCENARIO 1								
#9 Power Boiler (Oil)	All	28.60	10.63	10.63	23.44	150.24	341.5	9.57
#3 Recovery Boiler (Oil)	All	47.00	5.13	5.13	22.68	189.00	466.5	28.68
#3 Smelt Tank (Oil)	All	0.74	1.50	1.26	-	-	341.5	6.43
Lime Kiln (Oil)	All	1.05	2.62	2.62	5.25	52.54	344.3	7.92
TM #1 – Yankee Hood (NG)	All	0.01	0.10	0.10	0.57	0.52	654.3	17.79
TM #1 – Dust Vent (NG)	All	-	0.004	0.003	-	-	303.2	13.12
TM #2 – Yankee Hood (NG)	All	0.01	0.10	0.10	0.57	0.52	654.3	17.79
TM #2 – Dust Vent (NG)	All	-	0.004	0.003	-	-	303.2	13.12
TM #3 – TAD (NG)	All	0.01	0.15	0.15	0.72	1.90	400.9	21.17
TM #3 – Dust Vent (NG)	All	-	0.005	0.004	-	-	303.2	17.58
TM #4 – Yankee Hood (NG)	All	0.01	0.10	0.10	0.20	0.52	654.3	17.79
TM #4 – Dust Vent (NG)	All	-	0.004	0.003	-	-	303.2	13.12
MAXIMUM LICENSE ALLOWED SCENARIO 2								
#9 Power Boiler (NG)	All	23.44	10.63	9.58	23.44	150.24	328.7	10.67
#3 Recovery Boiler (NG)	All	47.00	5.13	5.13	22.68	189.00	474.3	31.85
#3 Smelt Tank (NG)	All	0.74	1.50	1.26	-	-	338.7	6.49
Lime Kiln (NG)	All	1.05	2.62	1.89	5.25	52.54	332.6	7.07
TM #1 – Yankee Hood (NG)	All	0.01	0.10	0.10	0.57	0.52	654.3	17.79
TM #1 – Dust Vent (NG)	All	-	0.004	0.003	-	-	303.2	13.12
TM #2 – Yankee Hood (NG)	All	0.01	0.10	0.10	0.57	0.52	654.3	17.79
TM #2 – Dust Vent (NG)	All	-	0.004	0.003	-	-	303.2	13.12
TM #3 – TAD (NG)	All	0.01	0.15	0.15	0.72	1.90	400.9	21.17
TM #3 – Dust Vent (NG)	All	-	0.005	0.004	-	-	303.2	17.58
TM #4 – Yankee Hood (NG)	All	0.01	0.10	0.10	0.20	0.52	654.3	17.79
TM #4 – Dust Vent (NG)	All	-	0.004	0.003	-	-	303.2	13.12
2016/2017 CURRENT ACTUALS								
#9 Power Boiler	3-Hour	23.44	-	-	-	-	328.7	10.67
	24-Hour	14.56	9.58	9.58	-	-		9.50
	Annual	1.65	6.17	6.17	9.70	-		7.47
#3 Recovery Boiler	3-Hour	47.00	-	-	-	-	474.3	31.85
	24-Hour	24.23	3.73	3.10	-	-		28.03
	Annual	3.50	3.21	2.66	15.84	-		26.76
#3 Smelt Tank	3-Hour	0.74	-	-	-	-	338.7	6.49
	24-Hour	0.23	1.26	1.26	-	-		5.71
	Annual	0.19	1.15	1.15	-	-		5.45
Lime Kiln	3-Hour	1.05	-	-	-	-	332.6	7.07
	24-Hour	0.98	1.33	1.33	-	-		7.07
	Annual	0.62	0.88	0.88	1.65	-		6.65

2010 BASELINE ($PM_{2.5}$ INCREMENT)								
#9 Power Boiler	Short Term	-	-	10.63	-	-	341.5	9.19
	Annual	-	-	7.85	-	-	341.5	6.79
#3 Recovery Boiler	Short Term	-	-	3.02	-	-	466.5	21.22
	Annual	-	-	1.60	-	-	466.5	20.08
#3 Smelt Tank	Short Term	-	-	1.03	-	-	341.5	4.40
	Annual	-	-	0.72	-	-	341.5	4.50
Lime Kiln	Short Term	-	-	2.62	-	-	344.3	7.92
	Annual	-	-	2.20	-	-	344.3	6.26
1987 BASELINE (NO_2 INCREMENT)								
#9 Power Boiler	Annual	-	-	-	21.54	-	341.5	8.23
Lime Kiln	Annual	-	-	-	4.68	-	344.3	5.38
1977 BASELINE (SO_2/PM_{10} INCREMENT)								
#9 Power Boiler	Short Term	145.29	17.72	-	-	-	449.8	9.37
	Annual	93.67	15.20	-	-	-	449.8	7.26
Lime Kiln	Short Term	0.79	3.94	-	-	-	344.3	5.77
	Annual	0.63	3.17	-	-	-	344.3	5.38
#8 Power Boiler	Short Term	71.60	5.82	-	-	-	449.8	6.16
	Annual	15.82	1.29	-	-	-	449.8	5.75

C. Single Source Modeling Impacts

AERMOD-PRIME refined modeling was performed for a range of operating scenarios that represented a range of boiler/equipment operations.

The significant impact model results for Woodland Pulp alone are shown in Table III-4. Maximum predicted impacts that exceed their respective significance level are indicated in boldface type. For comparison to the Class II significance levels, the impacts for 1-hour SO_2, 1-hour NO_2, 24-hour $PM_{2.5}$ and annual $PM_{2.5}$ were conservatively based on the maximum High-1st-High predicted values, averaged over five-years of meteorological data. All other pollutants/averaging periods were conservatively based on their maximum High-1st-High predicted values. For the purpose of determining maximum predicted impacts, all NO_x was conservatively assumed to convert to NO_2.

TABLE III-4: Maximum AERMOD-PRIME Significant Impact Results from Woodland Pulp

Pollutant	Averaging Period	Max Impact (μg/m³)	Receptor UTM E (m)	Receptor UTM N (m)	Receptor Elevation (m)	Class II Significance Level (μg/m³)	Class II Significance Distance (km)	Load Case
SO_2	1-hour	**229.78**	624,600	4,999,800	135.70	**10**[a]	>50.0	Max Oil
	3-hour	**214.94**	626,180	5,000,997	40.91	**25**	41.3	Max Oil
	24-hour	**83.37**	625,038	5,001,913	45.44	**5**	41.3	Max Oil
	Annual	**8.03**	626,180	5,001,397	27.82	**1**	4.2	Max Oil
PM_{10}	24-hour	**34.62**	626,130	5,001,397	28.73	**5**	9.0	Max NG
	Annual	**4.43**	626,033	5,001,490	31.18	**1**	2.3	Max NG
$PM_{2.5}$	24-hour	**27.98**	626,033	5,001,490	31.18	**1.2**	44.5	Max Oil
	Annual	**3.61**	626,110	5,001415	28.41	**0.3**	4.9	Max Oil
NO_2	1-hour	**228.15**	623,100	4,999,600	144.64	**10**[a]	>50.0	Max NG
	Annual	**7.51**	626,127	5,001,426	27.78	**1**	3.9	MaxNG
CO	1-hour	**2588.08**	622,600	4,999,100	135.61	**2,000**	4.0	Max NG
	8-hour	**768.46**	626,800	4,999,600	124.69	**500**	3.9	MaxNG

[a] Interim Significant Impact Level (SIL) adopted by Maine

D. Secondary Formation of $PM_{2.5}$

Since proposed $PM_{2.5}$ emissions for this modification are greater than 15 tpy and the increase in NO_x emissions is expected to be greater than 40 tpy, a review of secondary impacts due to $PM_{2.5}$ precursor emissions (secondary $PM_{2.5}$) is required.

The $PM_{2.5}$ compliance demonstration must account for both primary $PM_{2.5}$ from a source's direct PM emissions, as well as secondarily formed $PM_{2.5}$ from a source's precursor emissions of NO_x and SO_2. The formation of secondary $PM_{2.5}$ is dependent on the concentrations of precursor and relative species, atmospheric conditions and the interactions of precursors with other entities, such as particles, rain, fog or cloud droplets.

Since the contribution from secondary formation of $PM_{2.5}$ is not explicitly accounted for in AERMOD-PRIME, the impacts of secondarily formed $PM_{2.5}$ from Woodland Pulp was determined using a Tier I analysis following methodologies prescribed in USEPA's *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program.*

For a Tier I assessment, a source uses technically-credible empirical relationships between precursor emissions and secondary impacts, based upon USEPA modeling. Specifically, USEPA has performed single-source photochemical modeling to examine the range of modeled estimated impacts of secondary $PM_{2.5}$ formation for different theoretical source types (based on pollutant, stack height and location) for facilities in different geographical locations in the United States.

Using methodologies and values found in Appendix A of *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program*, Woodland Pulp estimated potential secondary $PM_{2.5}$ impacts due to precursor emissions by using a ratio of 'predicted secondary $PM_{2.5}$ concentration impact per ton of precursor emission', expressed in $\mu g/m^3$ per tpy. Using results from USEPA's hypothetical modeling scenarios, the 'predicted secondary $PM_{2.5}$ concentrations per ton of precursor emission' from the most conservative sources in Maine were multiplied by the tpy precursor emissions from Woodland Pulp. This procedure was followed for both NO_x and SO_2 precursors and the results summed to achieve a final estimated potential secondary $PM_{2.5}$ concentration, as shown in Table III-5.

TABLE III-5: Secondary $PM_{2.5}$ from NOx & SO_2 Precursors

Pollutant	Impact/EmissionsRatio ($\mu g/m^3$ / TPY)	Potential Increase of Precursors (TPY)	Estimated Secondary $PM_{2.5}$ Impacts ($\mu g/m^3$)
NOx	0.00024	71.62	0.0172
SO_2	0.00172	0.86	0.0015
Total Estimated Secondary $PM_{2.5}$ from NOx & SO_2 precursors			**0.0187**

Using this method, the total estimated secondary $PM_{2.5}$ impact due to Woodland Pulp's NO_x and SO_2 precursor emissions were predicted to be extremely low (<0.02 $\mu g/m^3$) and are not expected to contribute significantly to the $PM_{2.5}$ NAAQS and Class I or Class II increment impacts.

E. Combined Source Modeling Impacts

As indicated in boldface type in Table III-4, other sources not explicitly included in the modeling analysis must be accounted for by using representative background concentrations for the area.

Background concentrations, listed in Table III-6, are derived from representative rural background data for use in the Eastern Maine region.

TABLE III-6 : Background Concentrations

Pollutant	Averaging Period	Background Concentration ($\mu g/m^3$)	Monitoring Site
SO_2	1-hour	24	Presque Isle
	3-hour	18	Acadia National Park
	24-hour	11	
	Annual	1	
PM_{10}	24-hour	42	Baileyville
	Annual	10	
$PM_{2.5}$	24-hour	15	Bangor
	Annual	6	
NO_2	1-hour	43	Presque Isle
	Annual	4	
CO	1-hour	365	Acadia National Park
	8-hour	322	

The Department examined other nearby sources to determine if any impacts would be significant in or near the Woodland Pulp significant impact area. Due to the location of Woodland Pulp, extent of the predicted significant impact area on a pollutant-by-pollutant basis and other nearby source emissions, the Department has determined that no other sources need to be included in combined-source refined modeling analysis.

The maximum modeled impacts, which were explicitly normalized to the form of their respective NAAQS, were added with conservative rural background concentrations to demonstrate compliance with NAAQS, as shown in Table III-7.

Because all pollutant/averaging period impacts using this method meet NAAQS, no further NAAQS modeling analyses need to be performed. Final predicted impacts for PM_{10} and $PM_{2.5}$ were adjusted by 0.02 $\mu g/m^3$ to account for secondary formation of particulate, as calculated in Section D.

TABLE III-7: Maximum Combined Source Impacts (μg/m³)

Pollutant	Averaging Period	Max Impact (μg/m³)	Receptor UTM E (m)	Receptor UTM N (m)	Receptor Elevation (m)	Back-Ground (μg/m³)	Total Impact (μg/m³)	NAAQS (μg/m³)
SO_2	1-hour	153.91	626,130	5,001,397	28.73	24	177.91	196
	3-hour	180.18	626,180	5,001,047	36.13	18	198.18	1,300
	24-hour	62.46	626,230	5,001,397	26.92	11	73.46	365
	Annual	8.03	626,180	5,001,397	27.82	1	9.03	80
PM_{10}	24-hour	29.74	626,200	5,001,400	27.41	42	71.74	150
	Annual	4.45	626,033	5,001,490	31.18	10	14.45	50
$PM_{2.5}$	24-hour	18.21	626,105	5,001,457	27.33	15	33.21	35
	Annual	3.63	626,110	5,001,415	28.41	6	9.63	12
NO_2	1-hour	104.12	626,023	5,001,492	31.97	43	147.12	188
	Annual	6.76	626,118	5,001,420	28.10	4	10.76	100
CO	1-hour	1686.41	623,100	4,999,600	144.64	365	2,051.41	40,000
	8-hour	609.50	625,580	5,001,147	37.55	322	931.50	10,000

F. Secondary Formation of Ozone

The compliance demonstration must also account for the formation of ozone, which is a secondary pollutant formed through non-linear photochemical reactions, primarily driven by precursor emissions of NO_x and VOC in the presence of sunlight.

NO_x and VOC precursor contributions to the 8-hour daily maximum ozone are considered together to determine if the source's air-quality impact would exceed the critical threshold. Since the chemical formation of ozone associated with precursor emissions cannot be explicitly accounted for in AERMOD-PRIME, USEPA has developed a two-tiered approach for addressing single-source impacts.

The proposed emissions increase can be expressed as a percent of the lowest Modeled Emission Rates for Precursors (MERP) for each precursor and then the individual contributions summed. A value less than 100% indicates that the critical air-quality threshold will not be exceeded when considering the combined impacts of these precursors on 8-hour daily maximum ozone levels.

Using methodologies from *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program* and from values in Table 7.1 (*Most Conservative (Lowest) Illustrative MERP Values by Precursor, Pollutant and Region*), Woodland Pulp demonstrated compliance as follows:

(71.62 TPY NO_x increase / 170 TPY NO_x 8-hour daily maximum O_3 MERP) +

(160.90 TPY VOC increase / 1159 TPY default VOC 8-hour daily maximum O_3 MERP) =

0.42 + 0.14 = 0.56

The final calculated value is 0.56 (56%). A value less than 100% indicates that the USEPA's critical air-quality threshold value of 1 part per billion (ppb) for ozone will not be exceeded. Therefore, the proposed NO_x and VOC emissions are not expected to contribute to any new significant ozone formation.

G. Class II Increment

AERMOD-PRIME was used to predict maximum Class II increment impacts.

Results of the Class II increment analysis are shown in Tables III-8. Because all predicted increment impacts meet Class II increment standards, no additional Class II SO_2, PM_{10}, $PM_{2.5}$ or NO_2 increment modeling needed to be performed.

For the purpose of determining maximum predicted impacts, all NO_x was conservatively assumed to convert to NO_2. Final predicted impacts for PM_{10} and $PM_{2.5}$ were adjusted by 0.02 $\mu g/m^3$ to account for secondary formation of particulate, as calculated in Section D.

TABLE III-8: Class II Increment Consumption

Pollutant	Averaging Period	Max Impact ($\mu g/m^3$)	Receptor UTM E (km)	Receptor UTM N (km)	Receptor Elevation (m)	Class II Increment ($\mu g/m^3$)
SO_2	3-hour	23.35	625,980	5,001,247	30.48	512
	24-hour	2.70	625,611	5,001,753	31.04	91
	Annual	0.00	-	-	-	20
PM_{10}	24-hour	5.43	626,001	5,001,370	31.53	30
	Annual	0.02	-	-	-	17
$PM_{2.5}$	24-hour	4.66	625,368	5,001,444	43.14	9
	Annual	0.86	625,409	5,001,472	44.92	4
NO_2	Annual	0.73	625,401	5,001,467	44.78	25

Federal guidance and 06-096 C.M.R. ch. 115 require that any major new source or major source undergoing a major modification provide additional analyses of impacts that would occur as a direct result of the general, commercial, residential, industrial and mobile-source growth associated with the construction and operation of that source.

GENERAL GROWTH: Some increases in local emissions due to construction related activities are expected to occur for several months, with the majority of emissions due to truck and construction-vehicle traffic (such as soil removal, concrete delivery/pouring/finishing, delivery of materials, etc.). Increases in potential emissions of NO_x and $PM_{2.5}$ due to vehicle traffic will likely be temporary and short-lived. Emissions of dust from construction related activities will be minimized by the use of "Best Management Practices" for construction on-site.

RESIDENTIAL, COMMERCIAL AND INDUSTRIAL GROWTH: Population growth in the general area of Woodland Pulp can be used as a surrogate factor for the growth in emissions from residential combustion sources. Since the 1977 (PM_{10}), 1988 (NO_x) and 2010 ($PM_{2.5}$) baseline years, there has been a decrease in population in Washington County as show in Table III-9.

TABLE III-9: Washington County Population Growth

Pollutant	Baseline Year	Baseline Year Population	2017 Population	Percent Change from Baseline Year
NO_2	1988	35,308 (1990)	31,593	-10.5%
PM_{10}	1977	34,963 (1980)		-9.6%
$PM_{2.5}$	2010	32,827 (2010)		-3.8%

In addition, the manpower requirements, operations and support required for the construction and operation of the proposed project will be available from the local workforce in surrounding communities. Therefore, no new significant residential, commercial and/or industrial growth will follow from the modification associated with Woodland Pulp.

MOBILE SOURCE GROWTH: Since area and mobile sources are considered minor sources of NO_2, their contribution to increment has to be considered. Technical guidance from USEPA points out that screening procedures can be used to determine whether additional detailed analyses of minor source emissions are required. Compiling a source inventory may not be required if it can be shown that little or no growth has taken place in the impact area of the proposed source since the pollutant baseline dates were established.

Maine Department of Transportation has compiled Vehicle Miles Travelled (VMT) data for all counties in Maine from 1985 through 2016. As shown in Table III-10, the calculated growth in VMT over that time period, combined with the increasingly stringent federal NO_x emission requirements for mobile sources and the concurrent decrease in NO_2 background concentrations, indicate that mobile sources are not expected to significantly impact the available increment.

TABLE III-10: Washington County Growth in Vehicle Miles Travelled

Pollutant	Baseline Year	Baseline Year VMTs	2016 VMTs	Percent Change from Baseline Year
NO_2	1988	352,664,880	385,520,160	+9.3%

Therefore, additional analyses of mobile source NO_x emissions are not warranted.

H. Impacts on Plants, Soils & Animals

In accordance with guidance prescribed in USEPA's 1990 Prevention of Significant Deterioration manual, Woodland Pulp evaluated the impacts of its emissions using procedures described in *A Screening Procedure for the Impacts of Air Pollution on Plants, Soils and Animals*.

Maximum predicted impacts over all Class I and Class II areas from the AERMOD-PRIME modeling were compared to USEPA's 'Screening Concentrations' (see Table III-11), which represent the minimum concentration at which adverse growth effects or tissue injury in sensitive vegetation can be expected.

TABLE III-11: Maximum Impacts on Plants, Soils & Animals (μg/m³)

Pollutant	Averaging Period	Max Impact (μg/m³)	Screening Concentration (μg/m³)
SO_2	1-hour	229.78	917
	3-hour	214.94	786
	Annual	8.03	18
NO_2	4-hour	150.54	3,760
	8-hour	108.24	3,760
	Month	13.95	564
	Annual	7.51	94
CO	Week	451.62	1,800,000

Because all predicted impacts for all pollutants and averaging periods were below their respective screening concentrations, no further assessment of the impacts to plants, soils and animals is required, per USEPA guidance.

I. Class I Increment

AERMOD-PRIME was used to predict maximum Class I increment impacts in Moosehorn National Wildlife Refuge – Baring.

Results of the Class I increment analysis are shown in Table III-12. Because all predicted increment impacts meet Class I SO_2, PM_{10}, $PM_{2.5}$ and NO_2 increment standards, no additional Class I increment modeling needed to be performed.

For the purpose of determining maximum predicted impacts, all NO_x was conservatively assumed to convert to NO_2. Final predicted impacts for PM_{10} and $PM_{2.5}$ were adjusted by 0.02 μg/m³ to account for secondary formation of particulate, as calculated in Section D.

TABLE III-12: Class I Increment Consumption

Pollutant	Averaging Period	Max Impact (μg/m³)	Receptor UTM E (km)	Receptor UTM N (km)	Receptor Elevation (m)	Class I Increment (μg/m³)
SO_2	3-hour	1.07	632,104	4,995,894	73.76	25
	24-hour	0.00	-	-	-	5
	Annual	0.00	-	-	-	2
PM_{10}	24-hour	0.30	632,104	4,995,894	73.76	8
	Annual	0.02	-	-	-	4
$PM_{2.5}$	24-hour	0.10	634,766	4,994,097	110.20	2
	Annual	0.02	-	-	-	1
NO_2	Annual	0.00	-	-	-	2.5

J. Class I Air Quality Related Valuess

Based upon the magnitude of the SO_2, PM_{10} and NO_2 emissions increase and the distance from Woodland Pulp to the nearest Class I area, the US Fish & Wildlife Service (USFWS) has determined that a visibility assessment for plume blight is required for Moosehorn National Wildlife Refuge – Baring Unit (MNWR-Baring).

Using guidance obtained from USFWS staff and methodologies/procedures prescribed in *Workbook for Plume Visual Impact Screening and Analysis (Revised)* and *Federal Land Managers Air Quality Related Values Work Group: Phase I Report* (FLAG 2010), a VISCREEN Level 2 modeling analysis was performed for MNWR - Baring.

The VISCREEN model calculates the change in color difference index (Delta E) and contrast between a coherent plume and the viewing background. If the visual plume screening analysis can demonstrate that the increase in project emissions will not cause a plume with any hourly estimates greater than or equal to 2.0, or the absolute value of plume contrast greater than or equal to 0.05, that no further review of visibility impacts is required.

Inputs for the VISCREEN Level 2 modeling can be found in Table III – 13.

Table III – 13: VISCREEN Level 2 Inputs for MNWR - Baring

Pollutant		Maximum Hourly Emissions (g/s)	
Particulates (PM_{10})		0.47	
NO_x (as NO_2)		2.06	
Primary NO_2		0.00	
Soot		0.00	
Primary SO_4		0.00	
Background Characteristics			
Background Ozone		45 ppb	
Background Visual Range		166.0 km	
Plume-Source-Observer Angle		11.25°	
Level-2 Worst Case Meteorological Conditions			
Stability Class		F	
Wind Speed		3.0 m/s	
Level-2 Particle Characteristics			
Constituent		**Density (g/cm^3)**	**Mass Median Diameter (μg)**
Background Fine		1.5	0.3
Background Coarse		2.5	6.0
Plume Particulate		2.5	2.0
Plume Soot		2.0	0.1
Plume Sulfate		1.5	0.5
Distance Input Data			
Class I Area	**Source-Observer Distance**	**Minimum Source to Class I Distance**	**Maximum Source to Class I Distance**
MNWR - Baring	7.8 km	7.8 km	13.1 km

The results of the VISCREEN Level 2 visibility modeling are listed in Table III-14. Because all predicted visibility (Delta E and Contrast) impacts are below the critical values defined in *Workbook for Plume Visual Impact Screening and Analysis (Revised)*, no additional visibility modeled needs to be performed.

Table III – 14: VISCREEN Level 2 Results for MNWR - Baring

Background	Scatter Angle (degrees)	Azimuthal Angle (degrees)	Distance (km)	Alpha (degrees)	Inside MNWR - Baring	
					Delta E	**Contrast (+/-)**
Sky	10	153	13.1	16	0.585	0.005
Sky	140	153	13.1	16	0.408	-0.006
Terrain	10	84	7.8	84	1.339	0.004
Terrain	140	84	7.8	84	0.065	0.000
Critical Values (Sky & Terrain)					**2.000**	**0.050**

K. Summary

In summary, it has been demonstrated that Woodland Pulp in its proposed configuration will not cause or contribute to a violation of any SO_2, PM_{10}, $PM_{2.5}$, NO_2 or CO NAAQS or to Class I or II increments for SO_2, PM_{10}, $PM_{2.5}$ or NO_2.

In addition, it has also been determined that Woodland Pulp will not cause an impairment to visibility AQRVs in MNWR – Baring.

ORDER

Based on the above Findings and subject to conditions listed below, the Department concludes that the emissions from this source:

- will receive Best Practical Treatment,
- will not violate applicable emission standards,
- will not violate applicable ambient air quality standards in conjunction with emissions from other sources.

The Department hereby grants New Source Review License A-215-77-15-A pursuant to the preconstruction licensing requirements of 06-096 C.M.R. ch. 115 and subject to the standard and specific conditions below.

Severability. The invalidity or unenforceability of any provision of this License or part thereof shall not affect the remainder of the provision or any other provisions. This License shall be construed and enforced in all respects as if such invalid or unenforceable provision or part thereof had been omitted.

SPECIFIC CONDITIONS

Upon startup of TM3 or TM4 (whichever is first) all Specific Conditions found in NSR License A-215-77-6-A are Deleted and Replaced with the following Condition:

(1) **Tissue Machines (TM1, TM2, TM3, and TM4)**

A. Woodland Pulp is licensed to install and operate TM1, TM2, TM3 and TM4. TM1 and TM2 were installed in 2015 and 2016, respectively. [06-096 C.M.R. ch. 115, BACT]

B. Control Equipment

1. TM1, TM2, TM3, and TM4 shall each be equipped with wet dust collection systems that employ cyclone separators for control of particulate matter (PM, PM_{10}, and $PM_{2.5}$). These controls shall be operated whenever the associated tissue machine is in operation. [06-096 C.M.R. ch. 115, BACT]

2. The dryer burners of TM1, TM2, TM3, and TM4 shall utilize, at a minimum, low NO_x burners for control of NO_x. Condition (2)(A)(2)(b) shall supersede this condition where applicable. [06-096 C.M.R. ch. 115, BACT]

C. Emission Limits

1. Emissions from the Tissue Machines and associated dryers shall not exceed the following [06-096 C.M.R. ch. 115, BACT]:

Unit	PM lb/hr	PM_{10} lb/hr	$PM_{2.5}$ lb/hr	SO_2 lb/hr	NO_x lb/hr	CO lb/hr
TM1	1.29	2.44	2.38	0.03	4.52	4.12
TM2	1.29	2.44	2.38	0.03	4.52	4.12
TM3	1.90	3.59	3.51	0.11	8.97	15.07
TM4	1.29	2.44	2.38	0.03	4.52	4.12

2. Within 180 days of conducting NO_x performance testing on either TM1 or TM2 as required by Condition (3) of this license, Woodland Pulp shall propose, and apply to amend their license to incorporate, NO_x limits in units of ppm for TM1 and TM2. [06-096 C.M.R. ch. 115, BACT]

3. Within 180 days of conducting CO performance testing on either TM1 or TM2 as required by Condition (3) of this license, Woodland Pulp shall propose, and apply to amend their license to incorporate, CO limits in the units of ppm for TM1 and TM2. [06-096 C.M.R. ch. 115, BACT]

4. Within one year of startup of TM3, Woodland Pulp shall propose, and apply to amend their license to incorporate, a NO_x limit in units of ppm for TM3. [06-096 C.M.R. ch. 115, BACT]

5. Within one year of startup of TM3, Woodland Pulp shall propose, and apply to amend their license to incorporate, a CO limit in units of ppm for TM3. [06-096 C.M.R. ch. 115, BACT]

6. Within one year of startup of TM4, Woodland Pulp shall propose and apply to amend their license to incorporate, a NO_x limit in units of ppm for TM4. [06-096 C.M.R. ch. 115, BACT]

7. Within one year of startup of TM4, Woodland Pulp shall propose, and apply to amend their license to incorporate, a CO limit in units of ppm for TM4. [06-096 C.M.R. ch. 115, BACT]

8. Woodland Pulp shall demonstrate compliance with the applicable $PM/PM_{10}/PM_{2.5}$ emission limits for TM1, TM2, TM3, and TM4 listed in this license by conducting initial performance testing as described in Specific Condition (3) of this NSR license and complying with the following work practice standards:

   a. Monthly inspections of the wet dust collection system and cyclone separator on each tissue machine; and
   b. Recordkeeping of all maintenance, malfunctions, inspections, and downtime of the wet dust collection system and cyclone separators.

   [06-096 C.M.R. ch. 115, BACT]

9. Emissions from the Tissue Machines and associated dryers shall not exceed the following [06-096 C.M.R. ch. 115, LAER]:

Unit	VOC (Combustion only) lb/hr	VOC (Process only) lb/ADT
TM1	0.27	1.00
TM2	0.27	1.00
TM3	0.99	1.00
TM4	0.27	1.00

Compliance with the VOC emission limits shall be demonstrated by the recordkeeping requirements of this license.

D. Visible emissions from each Tissue Machine and its associated fuel burning equipment shall not exceed 10% opacity on a six-minute block average basis. Compliance shall be demonstrated in accordance with 40 C.F.R. Part 60, Appendix A, Method 9 upon request of the Department. [06-096 C.M.R. ch. 115, BACT]

E. Periodic Monitoring

1. Periodic monitoring for the control equipment on the Tissue Machines shall include the following:

   a. Records of the monthly inspections of the wet dust collection system and cyclone separator on each tissue machine; and
   b. Recordkeeping to document all maintenance, malfunctions, inspections, and downtime of the wet dust collection systems and cyclone separators.

   [06-096 C.M.R. ch. 115, BACT]

2. Periodic monitoring for all four Tissue Machines shall include the following:

   a. Monthly records of the amount of each VOC-containing chemical additive used on each machine;
   b. Records of the VOC content for each chemical additive used;
   c. Monthly records of the amount (ADT) of finished tissue product produced on each machine;
   d. Monthly calculations demonstrating compliance with the process VOC emission limits; and
   e. Monthly records of fuel use for each tissue machine.

   [06-096 C.M.R. ch. 115, BACT]

The following new Condition shall take effect upon startup of TM3 or TM4 (whichever is first):

(2) Tissue Machine (TM1, TM2, TM3, and TM4) NAAQS Compliance

In addition to the requirements of Condition (1) above, Woodland Pulp shall comply with the following requirements to demonstrate compliance with NAAQS and Class I and Class II Increment Standards:

A. Control Equipment

1. The dust collection system stacks from TM1 and TM2 shall each be retrofitted with venturi scrubbers no later than July 27, 2020. Once installed, the scrubbers shall be operated whenever the associated tissue machine is in operation.
   [06-096 C.M.R. ch. 115, §§ 4(A)(6)(j) and 7]

2. TM3 and TM4

   a. The dust collection system stacks from TM3 and TM4 shall each be equipped with venturi scrubbers for control of particulate matter (PM, PM_{10}, $PM_{2.5}$). These controls shall be operated whenever the associated tissue machine is in operation. [06-096 C.M.R. ch. 115, § 7]
   b. The yankee/through-air-dryer burners of TM3 and TM4 shall utilize ultra-low NO_x burners for control of NO_x. [06-096 C.M.R. ch. 115, § 7]

B. Emissions from the yankee/through-air-dryer sections of TM3 and TM4 shall each be vented to separate stacks that are each at least 117.75 feet AGL.
[06-096 C.M.R. ch. 115, § 7]

C. No later than July 27, 2020, Woodland Pulp shall increase the height of the yankee dryer section exhaust stacks of TM1 and TM2 to at least 117.3 feet AGL each.
[06-096 C.M.R. ch. 115, §§ 4(A)(6)(j) and 7]

D. Emission Limits

Upon installation of TM3 and TM4 and startup of the venturi scrubbers on TM1 and TM2, emissions from the Tissue Machines and associated dryers shall not exceed the following [06-096 C.M.R. ch. 115, § 7]:

Unit	PM lb/hr	PM_{10} lb/hr	$PM_{2.5}$ lb/hr	NO_x lb/hr
TM1	0.84	0.82	0.81	N/A*
TM2	0.84	0.82	0.81	N/A*
TM3	1.23	1.20	1.19	5.74
TM4	0.84	0.82	0.81	1.57

*NO_x emission limits for this equipment are addressed elsewhere in this license.

E. Periodic monitoring for the control equipment on TM1, TM2, TM3, and TM4 shall include the following. [06-096 C.M.R. ch. 115, § 7]

1. Monthly inspections of the venturi scrubber;
2. Recordkeeping to document all maintenance, malfunctions, inspections, and downtime of the venturi scrubber; and
3. Woodland Pulp shall monitor and record the flow rate through and pressure drop across each venturi scrubber at least once per shift.

The following new Condition shall take effect upon startup of TM3 or TM4 (whichever is first):

(3) **Initial Performance Testing**

A. TM1, TM2, and TM4

1. By July 27, 2021, Woodland Pulp shall demonstrate compliance with the PM lb/hr emission limits for TM1, TM2, and TM4 by conducting performance testing on the yankee hood stack and dust stack (both stacks tested simultaneously) on either TM1 or TM2 in accordance with 40 C.F.R. Part 60, Appendix A, Method 5 or other method as approved by the Department. [06-096 C.M.R. ch. 115, BACT]

2. By July 27, 2021, Woodland Pulp shall demonstrate compliance with the NO_x lb/hr emission limits for TM1 and TM2, by conducting performance testing on the yankee hood stack on either TM1 or TM2 in accordance with 40 C.F.R. Part 60, Appendix A, Method 7 or other method as approved by the Department. [06-096 C.M.R. ch. 115, BACT]

3. By July 27, 2021, Woodland Pulp shall demonstrate compliance with the CO lb/hr emission limits for TM1 and TM2 by conducting performance testing on the yankee hood stack on either TM1 or TM2 in accordance with 40 C.F.R. Part 60, Appendix A, Method 10 or other method as approved by the Department. [06-096 C.M.R. ch. 115, BACT]

4. Within 180 days of startup of TM4, Woodland Pulp shall demonstrate compliance with the NO_x lb/hr emission limit for TM4 by conducting performance testing on the yankee hood stack in accordance with 40 C.F.R. Part 60, Appendix A, Method 7 or other method as approved by the Department. [06-096 C.M.R. ch. 115, BACT]

5. Within 180 days of startup of TM4, Woodland Pulp shall demonstrate compliance with the CO lb/hr emission limit for TM4 by conducting performance testing on the yankee hood stack in accordance with 40 C.F.R. Part 60, Appendix A, Method 10 or other method as approved by the Department. [06-096 C.M.R. ch. 115, BACT]

B. TM3

1. Within 180 days of startup of TM3, Woodland Pulp shall demonstrate compliance with the PM lb/hr emission limit for TM3 by conducting performance testing on the TAD stack and dust stack (both stacks tested simultaneously) in accordance with 40 C.F.R. Part 60, Appendix A, Method 5 or other method as approved by the Department. [06-096 C.M.R. ch. 115, BACT]

2. Within 180 days of startup of TM3, Woodland Pulp shall demonstrate compliance with the NO_x lb/hr emission limit for TM3 by conducting performance testing on the TAD stack in accordance with 40 C.F.R. Part 60, Appendix A, Method 7 or other method as approved by the Department. [06-096 C.M.R. ch. 115, BACT]

3. Within 180 days of startup of TM3, Woodland Pulp shall demonstrate compliance with the CO lb/hr emission limit for TM3 by conducting performance testing on the TAD stack in accordance with 40 C.F.R. Part 60, Appendix A, Method 10 or other method as approved by the Department. [06-096 C.M.R. ch. 115, BACT]

The following new Condition shall take effect upon startup of TM3 or TM4 (whichever is first):

(4) NAAQS and Class I and Class II Increment Standards Compliance

A. Emissions from the #9 Power Boiler shall not exceed the following:

Pollutant	lb/hr	Origin and Authority
$PM_{2.5}$	84.4[1]	06-096 C.M.R. ch. 115, § 7
	76.0[2]	

1. When firing #6 fuel oil in combination with other fuels
2. When firing natural gas or propane in combination with other fuels

B. Emissions from the Smelt Dissolving Tank shall not exceed the following:

Pollutant	lb/hr	Origin and Authority
$PM_{2.5}$	10.0	06-096 C.M.R. ch. 115, § 7

C. Emissions from the Lime Kiln shall not exceed the following:

Pollutant	lb/hr	Origin and Authority
$PM_{2.5}$	20.8[1]	06-096 C.M.R. ch. 115, § 7
	15.0[2]	

1. When firing #6 fuel oil
2. When firing natural gas or propane

Upon startup of TM3 or TM4 (whichever is first), the following combined alternative emission limit shall replace the combined SO_2 lb/hr alternative emission limit for the #3 Recovery Boiler and #9 Power Boiler in any previously issued NSR License:

(5) **Alternative Emissions Cap**

The combined total SO_2 emissions from the #3 Recovery Boiler and the #9 Power Boiler shall not exceed 600 lb/hr (based on a three-hour block average) when firing #6 fuel oil in combination with other fuels or 559 lb/hr (based on a three-hour block average) when firing natural gas or propane in combination with other fuels. These alternative emissions caps shall be in effect for no more than 300 hours per calendar year, combined.
[06-096 C.M.R. ch. 115, BACT and § 7]

DONE AND DATED IN AUGUSTA, MAINE THIS 27 DAY OF July, 2018.

DEPARTMENT OF ENVIRONMENTAL PROTECTION

BY: Marc Allen Robert Cone for
PAUL MERCER, COMMISSIONER

PLEASE NOTE ATTACHED SHEET FOR GUIDANCE ON APPEAL PROCEDURES

Date of initial receipt of application: May 15, 2018
Date of application acceptance: May 15, 2018

Date filed with the Board of Environmental Protection:

This Order prepared by Jonathan E. Rice and Lynn Muzzey, Bureau of Air Quality.

Filed
JUL 27 2018
State of Maine
Board of Environmental Protection

NORTHEAST STATES FOR COORDINATED AIR USE MANAGEMENT
(NESCAUM)

NESCAUM BACT GUIDELINE

June 1991

I. INTRODUCTION

The Northeast States for Coordinated Air Use Management (NESCAUM) is an interstate association of the air quality divisions in the Northeast states: Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. NESCAUM's purpose is to exchange technical information and to promote cooperation and coordination of air pollution control issues among its member states. To accomplish this, NESCAUM sponsors frequent air quality training programs, participates in national debates, and promotes a variety of research initiatives.

Each of the NESCAUM states administers programs for the preconstruction review of new sources and modifications of existing sources. Some states administer a delegated version of the Federal Prevention of Significant Deterioration (PSD) regulations while others have developed their own regulations which, upon approval by the U.S. Environmental Protection Agency (EPA), provide the state the authority to issue federally enforceable permits. The minimum size of sources subject to review varies from state to state, but all states require that sources review available control technologies and that the source select the Best Available Control Technology (BACT). For new major sources or major modifications in nonattainment areas, the control technology required is Lowest Achievable Emission Rate (LAER).

The original policy was adopted by the NESCAUM Board of Directors at their meeting on October 11, 1988. Revisions to the policy were reviewed and approved by the Directors on June 11, 1991. This policy does not change regulations in any state or any existing PSD requirement for a top-down BACT analysis. Rather, it is intended to promote consistency between member states in methods of determining BACT and to provide prospective applicants with guidance on the level of analysis appropriate to support a proposed control technology. This policy defines a top-down analysis which starts by identifying the most stringent control available for a similar or identical source or source category. Working from that "top" case, the applicant must justify that the proposed emission levels represent BACT.

II. BACKGROUND

In the 1977 Amendments to the Clean Air Act, Congress adopted the Federal Prevention of Significant Deterioration Program. The program was designed to prevent air quality from deteriorating in areas where it was already better than the national ambient air

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quality standards. This objective was approached in two ways. First, the program established increments to limit the amount of additional sulfur dioxide and particulate matter allowed to be emitted above the baseline (which is existing air quality). Second, the program required that, regardless of existing air quality, new emission sources subject to PSD would be controlled to a level that represents BACT. This requirement not only precludes potential applicants from shopping for areas with less stringent emission limitations, but also promotes the research and development of more efficient and more economic alternative technologies.

EPA adopted regulations to implement the requirements of the 1977 Clean Air Act Amendments. These regulations were challenged by both industry and environmental organizations. In December 1979, in the case of Alabama Power et al., vs. Costle (13 ERC 1225), the Washington, D.C. Circuit Court upheld some provisions while overturning others. Subsequently, EPA promulgated changes to the regulatory requirements for new source review in amendments to Title 40 of the Code of Federal Regulations on August 7, 1980. On October 17, 1988, EPA promulgated a final rule which adopted PSD increments for nitrogen oxides. As of March 1991, these provisions constitute the regulatory requirements for the review of new sources and major modifications of existing sources in attainment areas that all programs must meet. These provisions may be changed as a result of the Clean Air Act Amendments of 1990.

III. PURPOSE

The purpose of this document is to promote consistent analysis of proposed control technologies and consistent procedures for reviewing BACT determinations from state to state. Establishing a uniform set of procedures will not only ensure equitable treatment for prospective applicants, but will also reduce pressure on reviewing agencies resulting from the argument that a similar source located elsewhere would not be subjected to the same requirements. It is also intended to provide prospective applicants with guidance on the BACT analysis process. Additional guidance may be obtained from EPA's draft New Source Review Workshop Manual (October 1990).

Each NESCAUM state has decided to use a top-down BACT analysis. This approach is based on identifying the best technology solution, allowing for environmental, energy, and economic considerations.

This guideline focuses on the type of data required in a preconstruction permitting application and how the data should be used in order to determine BACT. The guideline addresses how the emission control system proposed in the permitting application is determined to be BACT or why a more stringent level of emission control might be appropriate, considering available technology and economic, energy, and environmental factors.

The Clean Air Act places the responsibility for proposing BACT with the applicant and the responsibility of confirming BACT with the permitting agency. The top-down approach places the additional responsibility on the source to present and defend its proposal.

The level of analysis (or documentation) to support a BACT determination should be consistent from area to area. Since BACT is a case-by-case process, consistency does not necessarily mean that a new facility in one area will have an emission limit identical to that of the same type of facility in another area. Using a consistent approach to determine

BACT should ensure that the impacts of alternative emission control systems are measured by the same set of parameters.

IV. APPLICABILITY

The applicability criteria for imposition of the BACT requirement vary from state to state. In general, BACT is required of those new sources and modifications to existing sources which exceed some specified trigger level. The trigger is based on emission rates or source categories. States will have differing guidelines on calculating emissions. Therefore, the appropriate state permitting officials (see Appendix I) must be consulted at this stage in the process.

V. DEFINITIONS

This guideline uses "permit" to refer to what different states call permits, licenses, approvals, and plant approvals. The specific definitions of terms may vary from state to state. The applicant must work with each states' definitions. Therefore, the state permitting officials listed in Appendix I should be consulted.

VI. IDENTIFICATION OF CONTROL ALTERNATIVES

In carrying out a top-down BACT analysis, the applicant must first identify the most stringent control possible (usually referred to as Lowest Achievable Emission Rate, or LAER) and then quantify emissions. Since other alternatives will be compared against this top case, applicants should confer with the appropriate state contacts on what represents the most stringent control case. At this step of the BACT review process, no technically feasible alternative should be ruled out as a possible BACT candidate. Identifying control alternatives should not be limited to simply reviewing existing controls for the source category in question. The review must be broad enough to take into account controls applied to similar source categories and new control technologies. Finally, the alternatives identified should include the control alternatives representative of LAER for the source or category of source.

The starting assumption for the top-down approach is that the most stringent control possible is BACT. The burden of proof for applying a less stringent control rests in the applicant's case specific evaluation of the control alternatives. If the most stringent control for a specific pollutant is selected, the BACT evaluation for that pollutant is stopped. However, further evaluation of that control option's effectiveness on other pollutants may be required.

Failing to address the top case in an attempt to avoid stringent controls will result in the process being delayed while the applicant is required to reassess alternatives against the control option the permitting authority determines to be the top case.

When searching the record to identify the top case, the applicant must seek information on control technologies used throughout the United States, as well as applicable foreign control technologies. For example, Scandinavian pulping facility controls, German boiler and incinerator technology and operation controls, and Japanese controls for flue gas desulfurization have traditionally met very stringent emission control limits. Also, emission testing information on these technologies may be available to help establish the level of performance achievable with the specific technology.

A. Types of Controls

When identifying the top case and alternative control technologies, the following types of controls should be considered.

1. Existing Control Technology: a control technology which has been proven in practice for the source category. This should include both emission limitations imposed by other jurisdictions and test results which reflect what was actually achieved in performance.

2. Technically Feasible Alternatives: a control technology which has been demonstrated in practice on other source categories, but has not been demonstrated in practice on the class or category of source under review. Applying a control technology to a source category in which it has not been demonstrated is called control technology transfer.

3. Innovative Control Technology: a control technology that has never been applied to any source on a full scale, continuously operating basis. This technology may be chosen on the basis of pilot scale or short-term testing. In selecting an innovative control technology, there must be some reasonable level of expectation that the innovative options will out-perform the demonstrated control. Innovative control is not mandated but may be approved if submitted by the applicant.

4. Using Production Processes, Fuels, and Coatings That Are Inherently Lower Polluting
These options should be evaluated alone and in combination with add-on pollution control devices. Examples include adjusting raw material feed to reduce emissions, using methanol for low NO_X applications, and using powder coatings instead of solvent borne coatings where technically feasible. In considering these options, it is especially important to work closely with the appropriate state permitting officials who may allow some information to be treated as confidential or proprietary.

5. Specific Design or Operational Parameters: These options may include such factors as combustion zone temperature, combustion zone residence time, automatic combustion controls, pressure drop across control equipment, etc.

Both the source applicant and the reviewing agency should consider the use of clean processes, fuels, and solvents that are inherently lower polluting than what has been historically employed by a particular industry. The analyses for these alternatives should be conducted in the same manner as the analyses for more conventional BACT alternatives (described in later sections). A reviewing agency should seriously consider requiring the use of such alternatives if the BACT analysis justifies their use based on environmental, economic, and energy factors. Examples include the use of a dry process cement plant vs. a wet design; powder coatings vs. solvent-borne coatings; gas vs. fuel oil; electric boost or all-electric glass furnaces vs. fossil fuel fired; fluidized bed coal combustion vs. conventional firing, low sulfur residual oil, etc.

B. Sources of Information on Control Alternatives

There are numerous sources of information on control alternatives for various source categories. The following sources of information will be checked by the permitting authority. Hence they must be considered by the applicant preparing a BACT analysis.

1. BACT/LAER Clearinghouse

All applicants should check EPA's BACT/LAER Clearinghouse (telephone number: 919/ 541-5534) prior to submitting an application. The relevant information contained in the Clearinghouse should be summarized in the application. Reviewing agencies should verify that this information is correct and up-to-date.

2. EPA/State/Local Air Quality Permits

Applicants should be aware of permits issued for their industry. An effort must be made to obtain current information on BACT for these sources. Permitting agencies should maintain documentation of recent BACT determinations.

3. Federal/State/Local Permitting Engineers

Permitting engineers and engineering managers can provide information on projects under review for which BACT information may be available. BACT analyses under consideration will be available from these individuals before it appears in the Clearinghouse manual.

4. Control Equipment Vendors

Vendors have information on the most recent control technology, cost information, emission guarantees, and test results.

5. Trade Associations

Associations serving one sector often maintain permitting and emission test reports. Examples include the National Council for Air and Stream Improvement (NCASI) for pulp and paper industry, Electric Power Research Institute (EPRI) for electric generators and American Gas Cleaning Institute (AGCI) for information on air pollution control equipment.

6. Agencies or Companies Outside the United States

Where there is reason to believe that better controls are being used outside the United States, these groups should be consulted for information on the most recent advances in control technologies, control costs, test results, etc.

7. Inspection/Performance Test Reports

Recent test data may be useful in establishing emission limitations for sources. Inspection and performance test data may also reveal potential problems with a control technology or specific equipment.

8. Technical Papers and Journals

VII. EFFECTIVENESS RANKING OF CONTROL ALTERNATIVES

Once the applicant has identified the appropriate control alternatives, the applicant should rank them in order of control effectiveness, with the most effective control alternative at the top. This list should present an array of control alternatives, showing control efficiencies, expected emissions, economic costs, environmental benefits, energy costs, and other costs. The applicant should prepare a chart for each pollutant and for each emissions unit, or small group of units in the BACT analysis. These charts should be used to compare the control alternatives and to focus the selection of a control option as BACT.

VIII. EVALUATION OF CONTROL ALTERNATIVES

Three criteria are to be used if the applicant proposes using a control technology less effective than the top case. These three criteria are:

1. energy impacts

2. environmental impacts
3. economic impacts

Since the permitting agency will consider these criteria in its decision making process, it is important that applicants provide fully documented estimates of the emissions using alternative control as well as quantitative and qualitative environmental, energy, and economic impacts as described in Section IX. The evaluation process should be conducted in an incremental manner, from the top-down. The first step in this approach is to determine, for the emission source in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically or economically inappropriate for the source in question, then the applicant should determine the next most stringent level of control and evaluate it similarly. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. Thus, the top-down approach shifts the burden of proof to the applicant who must justify why the proposed source is unable to apply the best technology available. It also differs from other processes in that it requires the applicant to analyze a control technology only if the applicant opposes that level of control; other processes require a full analysis of all possible types and levels of control above the baseline case. If the applicant accepts the top alternative in the listing as BACT from an economic and energy standpoint, the applicant proceeds to consider whether collateral environmental impacts may justify selection of an alternative control option.

IX. IMPACT ANALYSIS OF CONTROL ALTERNATIVES

There are three main impacts to be examined in a BACT analysis. These are:

a. environmental impacts
b. energy impacts
c. economic impacts

Although the impact analyses are the important part of the selection process, the effectiveness of the control alternatives is usually the decisive factor affecting BACT selection.

A. Environmental Impacts

The first analysis is for environmental impacts. The applicant should estimate the net environmental impact associated with each control alternative. Both beneficial impacts and adverse impacts should be discussed and quantified, where possible. The analyses should be presented in the form of the incremental impact of each control alternative relative to the most stringent system identified as a control alternative.

The BACT determination, however, is totally independent of the amount or increment of air quality resources available. Insignificant air quality impact cannot provide a basis for accepting a less stringent control technology. The only case where the modeled impact of the proposed emissions should influence the emission limitation is when that modeling shows exceedances of the air quality standards or increments. In this case, the applicant must choose between using a control more stringent than BACT or changing the stack parameters or site location.

When weighing environmental impacts, the applicant should consider all air pollutants and the impact on other environmental media affected by the control alternative. This includes air pollutants which are not currently regulated under the Clean Air Act, but which may have a significant environmental impact. On June 3, 1986, the Administrator of the EPA remanded a PSD permitting to Region 9, instructing the Region to consider the effects of unregulated air pollutants when making a BACT determination for regulated pollutants. The analysis of unregulated air pollutants should be directed at developing an inventory of potential pollutants from a proposed source and evaluating the impact of each control alternative being considered for BACT on those pollutants.

The following is a brief outline of some of the environmental categories that should be considered during an analysis of environmental impacts.

1. Impacts on air quality
   - visible emissions
   - odor
   - visibility impairment
   - toxic air pollutants
   - noncriteria air pollutants
   - dioxin/furans
   - heavy metals
   - acid gases
   - non-photochemically reactive or toxic solvents
   - etc.
2. Impacts on water quality
3. Solid waste disposal impacts
4. Other environmental impacts
5. Noise
6. Steam plumes from cooling towers
7. Potential for accidental releases
8. Reliability (or the potential for malfunction and downtime)

Where approximately the same degree of emission reduction can be achieved by different technologies, preference should be given to the technology that achieves the reduction with the greatest degree of pollution prevention. For example, use of either low VOC coatings or utilizing carbon adsorption with reuse of the solvent are generally preferable to utilizing a thermal or catalytic incinerator.

<u>B. Energy Impacts</u>

The second analysis is for energy impacts. In analyzing energy impacts, the applicant should estimate the direct energy impacts of the control alternatives in units of energy consumption (Btus, kWh, barrels of oil, tons of coal, etc.). The energy requirements of the control options should be shown in terms of total and incremental (units of energy per ton of reduction) energy costs.

The analysis of energy impacts should also identify the type and amount of scarce fuels in the region that would be required. The analysis should also recognize the perils of relying on inherently low polluting fuels in lieu of controls since such decisions could result in greater emissions in the future due to unforeseen national energy policies or availability.

<u>C. Economic Impacts</u>

The third analysis is for economic impacts. In evaluating the economics of various BACT control options, primary consideration should be given to the cost effectiveness of an option and not to the economic situation of the source applicant. For control technologies that have been proven for the source category under review, the economic impact of requiring this technology on a source under review is less important than the cost effectiveness. There are two measures of cost effectiveness. These include: average cost effectiveness (total annualized costs of control divided by annual emissions reduction, or the difference between the baseline emission rate and the controlled emission rate), and incremental cost effectiveness (dollars per incremental ton removed). Baseline emissions used to determine the degree of pollution reduction must be based on a realistic scenario of the upper bound of uncontrolled emissions from the source, and must be derived in a manner consistent with the procedures specified in EPA's Draft New Source Review Workshop Manual (October 1990). Emission reduction credit can be taken for using inherently lower polluting processes.

When comparing two control devices with a similar level of control for the same pollutants, incremental cost may be used in conjunction with the average cost effectiveness to justify the elimination of the more stringent control level. However, incremental costs alone should not be used as a basis for justifying the elimination of a control option.

In the analysis of economic impacts, the applicant should estimate the approximate costs of the different emission control alternatives. The analysis should include a complete explanation of procedures used for assessing the economic impacts, any supporting data, and an itemization and explanation of all costs. Credit for tax incentives should be included, along with credits for product recovery savings and by-product sales generated from the use of the control system.

In evaluating the relative cost effectiveness of alternatives, calculations should be based on allowable emissions at maximum design capacity for 8,760 hours per year. If permit condition(s) limit operation to less than 8,760 hours per year, the analysis may also include data based on the allowed operation.

Annual costs should include the operation and maintenance cost plus the annualized cost for capital and design engineering. The capitalization should be based on the average useful life of equipment. The economic life of a control system typically varies between 10 and 20 years and should be determined consistent with data from EPA cost support documents and IRS Class Life Asset Depreciation Range System (publication, #534). This publication is referenced in EPA's October 1990 New Source Review Workshop Manual.

Applicants are responsible for fully documenting all relevant cost information. Vendor quotations or other reliable means should be the primary basis for estimates. Cost estimates can also be derived using the most recent methods included in OAQPS Control Cost Manual, 4th edition (EPA 450/3-9-006, January 1990), and Appendix B (Estimating Control Costs) of EPA's Draft New Source Review Workshop Manual (October 1990), and any subsequent revisions to these manuals. Whenever the cost estimates are outside the range contained in these documents, the applicant is responsible for substantiating the estimates. The applicant must note the year used in cost estimates and adjust all calculations to reflect costs for that year. The limits of the process segment to be costed (or control system battery limits) should be specified in the BACT analysis and should have design parameters consistent with those that would achieve the emission estimates used in other portions of the application (i.e., dispersion modeling inputs, permit emission limits). Table 1 below summarizes some design parameters that are important in determining system costs.

Table 1 Control System Design Parameters Examples

Control	Design Parameter Example
Wet Scrubbers	Scrubber liquor (water, chemicals, etc.) Gas pressure drop Liquid/ gas ratio

Carbon Adsorbers	Specific chemical species Gas pressure drop lbs. carbon/ lbs. pollutant
Condensers	Condenser type Outlet temperature
Incineration	Residence time Temperature
Electrostatic Precipitator	Specific collection area (ft^2, acfm) Voltage density
Fabric Filter	Air to cloth ratio Pressure drop
Selective Catalytic Reduction	Space velocity Ammonia to NOx molar ratio Pressure drop Catalyst life

SOURCE: EPA Draft New Source Review Workshop Manual (October 1990).

A complete economic analysis should compare costs of controls both within the specific source category under review and, as a comparison of costs, for other industries, on the basis of dollars per ton of pollutant removed. The analysis should also represent the control option costs in terms of operations at full capacity (8,760 hours per year) and the control cost as a percent of the total project cost. If permit condition(s) limit operation to less than 8,760 hours per year, the analysis may also include data based on the allowed operation.

The analysis must be source specific, but should also be general enough to consider normal costs for doing business in a given field. A demonstration by an applicant that it cannot afford to construct a facility using the most stringent technology does not allow the more stringent technology to be rejected as BACT. Rather it is a statement of whether the applicant is financially capable of conducting business in that field.

X. ENFORCEABILITY

The BACT determination for each pollutant must result in a federally enforceable permit. BACT must be specified not only in terms of a control technology, but also in terms of emission limits and/or design, equipment, work practice, or operational standards (temperature, pressure drop, flow rates, pH control, etc.) that are federally enforceable. The BACT limits must be point specific and must include appropriate averaging times, reference test methods, and a method for ensuring continuous compliance.

This guideline was adopted by the NESCAUM Board of Directors on June 11, 1991.

APPENDIX I

STATE BACT CONTACTS

CONNECTICUT
S. Amarello, E. Bouffard, S. Peplau 203/ 566-8230
Connecticut Department of Environmental Protection
Bureau of Air Management
165 Capitol Avenue
Hartford, CT 06106

MAINE
M. Cone, E. Kennedy 207/ 289-2437
Maine Department of Environmental Protection
Bureau of Air Quality Control
State House Station 17
Augusta, ME 04330

MASSACHUSETTS
J. Belsky, T. Cussons, C. Goff, D. Squires, V. Steeves 617/ 292-5630
Massachusetts Department of Environmental Protection
Division of Air Quality Control
One Winter Street, 8th Floor
Boston, MA 02108

NEW HAMPSHIRE
A. Bodnarik, D. Davis 603/ 271-1370
New Hampshire Department of Environmental Services
Air Resources Division
64 North Main Street, Caller Box 2033
Concord, NH 03302-2033

NEW JERSEY

Minor Source Air Pollution Control Permits
L. Mikolajczyk 609/ 633-8220
Chief, Bureau of New Source Review
New Jersey Department of Environmental Protection
Division of Environmental Quality
401 East State Street, CN 027
Trenton, NJ 08625

Major Source Air Pollution Control Permits
I. Atay 609/ 984-3023
Chief, Bureau of Engineering and Regulatory Development
New Jersey Department of Environmental Protection
Division of Environmental Quality
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Trenton, NJ 08625

NEW YORK
J. Davis, R. Parker 518/ 457-2044
New York Department of Environmental Conservation
Division of Air
50 Wolf Road
Albany, NY 12233

RHODE ISLAND
D. McVay 401/ 277-2808
Rhode Island Department of Environmental Management
Division of Air and Hazardous Materials
291 Promenade Street
Providence, RI 02908

VERMONT
D. Elliott, B. Fitzgerald, J. Perreault 802/ 244-8731
Vermont Department of Environmental Conservation
Air Pollution Control Division
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OTHER CONTACTS

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L. Hamjian 617/ 565-3250
JFK Federal Building, Room 2311
Boston, MA 02203

EPA Region II
W. Baker, K. Mangels 212/ 264-2517
26 Federal Plaza
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EPA Office of Air Quality Planning and Standards
BACT/LAER Clearinghouse 919/ 541-5534

BACT gdln-rev 7/91;7/25/91

IN RE LA PALOMA ENERGY CENTER, LLC

PSD Appeal No. 13-10

ORDER DENYING REVIEW

Decided March 14, 2014

Syllabus

Sierra Club petitions the Environmental Appeals Board ("Board") to review a greenhouse gas ("GHG") prevention of significant deterioration permit that Region 6 ("Region") of the United States Environmental Protection Agency ("EPA") issued to the La Paloma Energy Center, LLC ("LPEC") pursuant to Clean Air Act § 165, 42 U.S.C. § 7475. The permit authorizes LPEC to construct and operate a 637- to 735-megawatt natural gas-fired power plant in Harlingen, Texas. Sierra Club challenges the permit's emission limits for greenhouse gases on two grounds, claiming that the Region clearly erred or abused its discretion (1) by failing to base the permitted GHG emission limits for the combined cycle natural gas-fired combustion turbines that will be used at this facility on the energy efficiency of the most efficient of the three turbine models that LPEC identified for potential use at this facility, and (2) by declining to require LPEC to consider adding a solar thermal energy component to the proposed facility in order to further reduce GHG emissions because the Region incorrectly concluded that solar technology would "redefine the source."

Held: The Board denies the petition for review of the Region's final permit decision.

(1) Issue Concerning the Permit's GHG Emission Limits for the Combustion Turbines

> Sierra Club has failed to demonstrate that the Region clearly erred or abused its discretion in establishing the GHG permit limits for the combustion turbines at the proposed LPEC facility. The Board finds no support in EPA's BACT guidance for Sierra Club's position that the three specific turbine models proposed by LPEC *must* be identified as separate control technologies throughout the Region's five-step analysis. The Region had a rational basis for its determinations that all three of the permitted turbine models are comparably efficient on a performance basis, that the assigned BACT limits are substantially equivalent except for marginal differences attributable to capacity, and that the GHG emission limits for all three turbine models represent BACT for highly efficient combined cycle combustion turbines.

(2) Issue Concerning Region's Conclusion That Solar Technology Would "Redefine the Source"

> Sierra Club has failed to demonstrate that the Region abused its discretion in concluding that adding solar technology to this facility would "redefine the source." Under the circumstances of this case, the business purposes and site-specific constraints described in the administrative record support the Region's conclusion that the addition of supplemental solar power to this facility would constitute redesign of the source.

Before Environmental Appeals Judges Catherine R. McCabe, Randolph L. Hill, and Kathie A. Stein.

Opinion of the Board by Judge Catherine R. McCabe:

I. *STATEMENT OF THE CASE*

Sierra Club filed a timely petition seeking Environmental Appeals Board ("Board") review of a Clean Air Act greenhouse gas ("GHG") prevention of significant deterioration ("PSD") permit, PSD-TX-1288-GHG, that U.S. Environmental Protection Agency ("EPA" or "Agency") Region 6 ("Region") issued to La Paloma Energy Center, LLC ("LPEC") on November 6, 2013. The permit authorizes LPEC to construct and operate a 637- to 735-megawatt ("MW") natural gas-fired power plant in Harlingen, Texas. *See* PSD Permit for Greenhouse Gas Emissions Issued Pursuant to the Requirements at 40 C.F.R. § 52.21 ("Permit") at 1-2 (Nov. 6, 2013) (Administrative Record Index No. ("A.R.") V.01). The petition challenges the permit's emission limits for GHGs on two grounds. Both the Region and LPEC filed responses to the petition. The Board held a status conference/oral argument in this matter on February 12, 2014. For the reasons set forth below, the Board denies the petition for review of the Region's final permit decision.

II. *ISSUES*

This appeal presents the following issues for resolution:

A. Has Sierra Club demonstrated that the Region clearly erred or abused its discretion in establishing the GHG permit limits for the combustion turbines at the LPEC facility?

B. Has Sierra Club demonstrated that the Region abused its discretion in concluding that adding solar technology to the LPEC facility would "redefine the source?"

III. *STANDARD OF REVIEW*

Section 124.19 of Title 40 of the Code of Federal Regulations governs Board review of a PSD permit. In any appeal from a permit decision issued under part 124, the petitioner bears the burden of demonstrating that review is warranted. *See* 40 C.F.R. § 124.19(a)(4). The Board has discretion to grant or deny review of a permit decision. *See In re Avenal Power Ctr., LLC*, 15 E.A.D. 384 (EAB 2011) (citing Consolidated Permit Regulations, 45 Fed. Reg. 33,290, 33,412 (May 19, 1980)), *appeal docketed sub nom. Sierra Club v. EPA*, No. 11-73342 (9th Cir. Nov. 3, 2011). The Board will deny review of a permit decision unless the petitioner demonstrates that it is based on a clearly erroneous finding of fact or conclusion of law, or involves a matter of policy or exercise of discretion that warrants review. 40 C.F.R. § 124.19(a)(4)(i)(A)-(B). In considering whether to grant or deny review of a permit decision, the Board is guided by the preamble to the regulations authorizing appeal under part 124, in which the Agency stated that the Board's power to grant review "should be only sparingly exercised," and that "most permit conditions should be finally determined at the [permit issuer's] level." 45 Fed. Reg. at 33,412; *see also* Revisions to Procedural Rules Applicable in Permit Appeals, 78 Fed. Reg. 5,280, 5,281 (Jan. 25, 2013).

When evaluating a challenged permit decision for clear error, the Board examines the administrative record that serves as the basis for the permit to determine whether the permit issuer exercised his or her "considered judgment." *See, e.g., In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 191, 224-25 (EAB 2000); *In re Ash Grove Cement Co.*, 7 E.A.D. 387, 417-18 (EAB 1997). The permit issuer must articulate with reasonable clarity the reasons supporting its conclusion and the significance of the crucial facts it relied upon when reaching its conclusion. *E.g., In re Shell Offshore, Inc.*, 13 E.A.D. 357, 386 (EAB 2007). As a whole, the record must demonstrate that the permit issuer "duly considered the issues raised in the comments" and ultimately adopted an approach that "is rational in light of all information in the record." *In re Gov't of D.C. Mun. Separate Storm Sewer Sys.*, 10 E.A.D. 323, 342 (EAB 2002); *accord In re City of Moscow*, 10 E.A.D. 135, 142 (EAB 2001); *In re NE Hub Partners, LP*, 7 E.A.D. 561, 568 (EAB 1998), *review denied sub nom. Penn Fuel Gas, Inc. v. EPA*, 185 F.3d 862 (3d Cir. 1999). Permit issuers therefore must provide sufficient documentation in the record to justify decisions to set less stringent BACT limitations where the record suggests that more stringent levels may be achievable. *In re Pio Pico Energy Ctr.*, 16 E.A.D. 56, 130-34 (EAB 2013); *accord In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 131 (EAB 1999) ("The BACT analysis is one of the most critical elements of the PSD permitting process. As such, it should be well documented in the administrative record."). On matters that are fundamentally technical or scientific in nature, the

Board typically will defer to a permit issuer's technical expertise and experience, as long as the permit issuer adequately explains its rationale and supports its reasoning in the administrative record. *See In re Dominion Energy Brayton Point, LLC*, 12 E.A.D. 490, 510, 560-62, 645-47, 668, 670-74 (EAB 2006); *see also, e.g.*, *In re Russell City Energy Ctr.*, 15 E.A.D. 1, 29-32 (EAB 2010), *petition denied sub nom. Chabot-Las Positas Cmty. Coll. Dist. v. EPA*, 482 F. App'x 219 (9th Cir. 2012); *NE Hub*, 7 E.A.D. at 570-71.

In reviewing an exercise of discretion by the permitting authority, the Board applies an abuse of discretion standard. *E.g.*, *In re Guam Waterworks Auth.*, 15 E.A.D. 437, 443 n.7 (EAB 2011). The Board will uphold a permitting authority's reasonable exercise of discretion if that decision is cogently explained and supported in the record. *See Ash Grove*, 7 E.A.D. at 397 ("[A]cts of discretion must be adequately explained and justified."); *see also Motor Vehicles Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 48 (1983) ("We have frequently reiterated that an agency must cogently explain why it has exercised its discretion in a given manner * * *.").

IV. *SUMMARY OF DECISION*

For the reasons stated below, the Board concludes that (1) Sierra Club has not demonstrated that the Region clearly erred or abused its discretion in establishing the GHG permit limits for the combustion turbines at the proposed LPEC facility, and (2) Sierra Club has not demonstrated that the Region abused its discretion in concluding that adding solar technology to this facility would "redefine the source." Accordingly, the Board denies Sierra Club's petition for review.

V. *PROCEDURAL AND FACTUAL HISTORY*

In April 2012, LPEC submitted a GHG PSD permit application to the Region to construct a new natural gas-fired electric generating plant in the City of Harlingen, Texas.[1] *See* U.S. EPA Region 6, Statement of Basis, Draft Greenhouse

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[1] In 2011, EPA issued a final rule promulgating a federal implementation plan in Texas that made EPA Region 6 the PSD permitting authority for the pollutant GHGs in the State. *See* Federal Implementation Plan Regarding Texas's PSD Program, 76 Fed. Reg. 25,178 (May 3, 2011) (promulgating 40 C.F.R. § 52.2305). The Texas Commission on Environmental Quality ("TCEQ") is the PSD permitting authority for all other pollutants. *See id*. at 25,179 n.2; SOB at 1. Consequently, in addition to the PSD GHG permit application it submitted to the Region, which is the subject of this appeal, LPEC also

Gas Prevention of Significant Deterioration Preconstruction Permit for the La Paloma Energy Center, LLC ("SOB") at 1 (Mar. 2013) (A.R. III.03). LPEC revised its application in July 2012.[2] LPEC, PSD GHG Permit Application for a Combined Cycle Power Plant at LPEC, Cameron County, Texas, at 1, 16 (revised July 17, 2012) (A.R. I.03) [hereinafter Revised Application]. LPEC plans to produce electricity to sell to the Electricity Reliability Council of Texas ("ERCOT") power grid. SOB at 5-6. In its application, LPEC stated that the proposed facility would consist of two natural gas-fired combined cycle combustion turbines, each exhausting to a fired heat recovery steam generator to produce steam to drive a shared steam turbine. Revised Application at 1. LPEC explained that, while "final selection of the combustion turbine model would not be made until after the permit was issued," it was considering three models, each producing different maximum baseload power: the General Electric 7FA (183 MW) ("GE turbine"), the Siemens SGT6-5000F(4) (205 MW) ("Siemens 4 turbine"), and the Siemens SGT6-5000F(5) (232 MW) ("Siemens 5 turbine"). *Id*. Combined with the steam turbine's output capacity of approximately 271 MW, the combustion turbines would produce a total generating capacity at this facility of 637, 681, or 735 MW of electricity, depending upon which combustion turbine model is finally selected. *Id*.

The Region issued a draft GHG PSD permit for public comment for 30 days, beginning on March 20, 2013. *See* U.S. EPA Region 6, *Responses to Public Comments* ("RTC") at 3 (Nov. 6, 2013) (A.R. V.02). In the draft permit, the Region specified three different sets of emission limits based on the three potential capacity scenarios. *See* SOB at 16. Sierra Club submitted comments on the draft permit. *See generally* Letter from Travis Ritchie, Sierra Club, to Aimee Wilson, Air Permits Section, U.S. EPA Region 6 (Apr. 19, 2013) ("Sierra Club Comments").

On November 6, 2013, the Region issued its final permitting decision and a document responding to the comments it had received. *See* Permit at 1; RTC at 1. The final permit retained the three different sets of emission limits.[3] Sierra Club

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submitted a PSD permit application for non-GHG pollutants to TCEQ for the same proposed project. *Id*.

[2] LPEC revised its application several times after July 2012. The Board refers to the July 2012 revision in this decision because that is the version the parties submitted and discussed on appeal.

[3] The permit specifies three types of emission limits for each capacity scenario: (1) output rate-based emission limits (pounds of carbon dioxide emitted per megawatt hour of electricity produced (lb CO_2/MWh)); (2) startup limits (lb CO_2/hour); and (3) total annual GHG limits on a mass basis (tons per year). *See* Permit at 7-13; SOB at 16. The parties'

filed a timely appeal. Both the Region and LPEC filed responses to the petition. LPEC also filed a Motion to Expedite and Resolve Petition requesting that the Board expedite consideration of this matter and issue a final decision by January 31, 2014. The Board held a status conference/oral argument in this matter on February 12, 2014, at which all parties participated.

VI. *OVERVIEW OF PSD LEGAL REQUIREMENTS AND BACT ANALYSIS*

The PSD provisions of the Clean Air Act govern air pollution in "attainment" areas, where the air quality meets or is cleaner than the national ambient air quality standards, as well as in areas that EPA is unable to classify as either attainment or "non-attainment." CAA §§ 160-69, 42 U.S.C. §§ 7470-79; *accord In re Rockgen Energy Ctr*., 8 E.A.D. 536, 541 (EAB 1999). The statutory PSD provisions are largely carried out through a regulatory process that requires new major stationary sources in attainment (or unclassifiable) areas, such as the LPEC facility, to obtain preconstruction permits. CAA § 165, 42 U.S.C. § 7475; 40 C.F.R. § 52.21.

The Clean Air Act and Agency PSD regulations require that every proposed PSD permit be subjected to a preconstruction review by the permitting authority, which must include a public hearing with the opportunity for interested persons to comment on the air quality impact of the proposed source, alternatives thereto, control technology, and other appropriate considerations. CAA § 165(a)(2), 42 U.S.C. § 7475(a)(2). New major stationary sources and major modifications of such sources are required to employ the "best available control technology" ("BACT") to minimize emissions of regulated pollutants. CAA § 165(a)(4), 42 U.S.C. § 7475(a)(4); 40 C.F.R. § 52.21(j)(2). The statute defines BACT as follows:

> The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.

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arguments in this case focus on the output-based emission limits rather than the other two sets of emission limits.

CAA § 169(3), 42 U.S.C. § 7479(3); *accord* 40 C.F.R. § 52.21(b)(12) (similar regulatory definition). As the Board explained in *In re Northern Michigan University ("NMU")*, the BACT definition requires permit issuers to "proceed[] on a case-by-case basis, taking a careful and detailed look, attentive to the technology or methods appropriate for the particular facility, [] to seek the result tailor-made for that facility and that pollutant." 14 E.A.D. 283, 291 (EAB 2009) (citations and quotations omitted). The BACT determination results in the selection of an emission limitation representing application of control technology or methods appropriate for the particular facility. *In re Prairie State Generating Co.*, 13 E.A.D. 1, 12 (EAB 2006), *aff'd sub. nom Sierra Club v. U.S. EPA*, 499 F.3d 653 (7th Cir. 2007); *In re Three Mountain Power, LLC*, 10 E.A.D. 39, 47 (EAB 2001); *In re Knauf Fiber Glass, GMbH*, 8 E.A.D. 121, 128-29 (EAB 1999).

In 1990, EPA issued draft guidance for permitting authorities to use in analyzing PSD requirements (among others) in a consistent and systematic way. *See generally* Office of Air Quality Planning & Standards, U.S. EPA, *New Source Review Workshop Manual* 1 (draft Oct. 1990) ("*NSR Manual*").[4] The NSR Manual sets forth a "top-down" process for determining BACT for each particular regulated pollutant that is summarized as follows:

> The top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent – or "top" – alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case.

[4] Notably, the NSR Manual is not a binding Agency regulation, and consequently strict application of the methodology described in it is not mandatory nor is it the required vehicle for making BACT determinations. *E.g.*, *NMU*, 14 E.A.D. at 291; *Prairie State*, 13 E.A.D. at 6 n.2; *Knauf*, 8 E.A.D. at 129 n.13. Nevertheless, because it provides a framework for determining BACT that assures adequate consideration of the statutory and regulatory criteria, the NSR Manual has guided state and federal permit issuers, as well as PSD permit applicants, on PSD requirements and policy for years. *E.g.*, *NMU*, 14 E.A.D. at 291; *In re Cardinal FG Co.*, 12 E.A.D. 153, 162 (EAB 2005); *see also In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 183 (EAB 2000) ("This top-down analysis is not a mandatory methodology, but it is frequently used by permitting authorities to ensure that a defensible BACT determination, involving consideration of all requisite statutory and regulatory criteria, is reached.").

Id. at B.2. Permit issuers apply the top-down method on a case-by-case basis to each permit they evaluate. *See id.* at B.1 (explaining that all BACT analyses are done case-by-case). The NSR Manual's recommended top-down analysis employs five steps:

> Step 1: Identify all available control options with potential application to the source and the targeted pollutant;
>
> Step 2: Analyze the control options' technical feasibility;
>
> Step 3: Rank feasible options in order of effectiveness;
>
> Step 4: Evaluate the energy, environmental, and economic impacts of the options; and
>
> Step 5: Select a pollutant emission limit achievable by the most effective control option not eliminated in a preceding step.

Id. at B.5-.9.

VII. *ANALYSIS*

This case arises in the relatively new context of PSD permitting authorities' efforts to develop BACT permit limits for GHGs based on energy efficiency. EPA's 2011 GHG Permitting Guidance explains that BACT analysis for GHGs should be conducted in the same manner as it is done for any other regulated pollutant. U.S. EPA, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases* 17 (Mar. 2011). That is, EPA will continue to apply its pre-existing framework for BACT analysis, including the five-step "top-down" analytical method described in the 1990 NSR Manual. *Id.* The GHG Permitting Guidance recognizes that BACT emission limits for GHGs often will need to be based on energy efficiency, as the use of add-on controls to reduce GHG emissions is not as well-advanced as it is for most combustion-driven pollutants. *Id.* at 21, 29. Accordingly, in this case the Region based the GHG emission limits for LPEC's proposed new power plant on energy-efficient design and other energy efficiency measures that are available for use at this facility.

Sierra Club argues that the Region conducted a faulty BACT analysis and has not gone far enough to assure that the facility will achieve the maximum reduction of GHGs that is required by the Clean Air Act. Specifically, Sierra Club objects that the Region clearly erred or abused its discretion (1) by failing to base the permitted GHG emission limits for the combined cycle natural gas-fired combustion turbines that will be used at this facility on the energy efficiency of the most efficient of the three turbine models that LPEC identified for potential use at this facility, and (2) by declining to require LPEC to consider adding a solar thermal energy component to the proposed facility in order to further reduce GHG emissions. Pet. at 7-29.

For the reasons explained below, the Board concludes that Sierra Club has failed to demonstrate that the Region clearly erred or abused its discretion in its BACT determinations in this case.

A. *The Region Did Not Clearly Err or Abuse its Discretion in Establishing the GHG Permit Limits for the Combustion Turbines at the LPEC Facility*

As explained in Part V above, LPEC has not yet made a final selection of the combustion turbine model it will use at the LPEC facility. LPEC explains that, "[b]ecause the PSD permitting process can take months or years to complete, the project developer generally does not select a particular turbine for a project until the final stages of project development." LPEC Resp. at 8. LPEC further explains that the business considerations affecting its final selection of turbine model include the projected demand for electricity from these units (which informs the amount of generation capacity that is needed) and the turbines' relative efficiency, reliability, and cost. *See id.*; *see also* RTC at 5 (describing factors applicants typically consider in selecting turbines).[5]

The Region accommodated LPEC's desire to retain the flexibility to choose the specific turbine model for its facility at a later stage of the process by specifying separate GHG emission limits in LPEC's permit for each of the three turbine models under consideration. The permit requires LPEC to submit a permit modification request to the Region once LPEC has selected the final turbine model to eliminate the non-selected models from the permit. Permit at 13. At oral argument, LPEC represented that it has obtained all other necessary permits for construction of the facility and is now prepared to finalize its financing arrangements and construction plans upon EPA's final issuance of the PSD permit under consideration in this matter. Oral Arg. Tr. at 10-11. LPEC further stated that it currently plans to select the GE turbine (the smallest of the three turbine models). *Id*.

Sierra Club argues that the Region failed to conduct a proper BACT analysis in setting the output-based GHG emission limits for the combustion turbines. Sierra

[5] *See also NSR Manual* at B.61 (recognizing that, in selecting gas turbine models, a utility typically considers "the peak demand which must be met, efficiency of the gas turbine, reliability requirements, and the experience of the utility with the operation and maintenance service of the particular manufacturer and turbine design").

Club objects to the Region's establishing "alternate" GHG limits specific to each of the three models, allowing LPEC to select whichever model it chooses after the permit is issued. In Sierra Club's view, the permitted GHG emission limits must be based on the lowest GHG emission limit that any of the three turbine models can achieve, regardless of which model LPEC finally selects. Specifically, Sierra Club argues that the output-based permit limits must be set at the 909.2 lb CO_2 /MWh emission limit that the Region specified for the Siemens 4 turbine. Pet. at 9 & 14 n.5. The output-based permit limits for the Siemens 5 and GE turbines are slightly higher (912.7 and 934.5 lb CO_2/MWh, respectively).[6] Permit at 13.

At the outset, it is important to be clear what is actually at issue in this case. The parties have characterized this case as raising the issue of whether the Region can establish "alternate limits" as BACT for the LPEC combustion turbines. Sierra Club objects that this approach will allow permit applicants essentially to choose their own emission limits.[7] The Board does not agree. First, the Region, not LPEC, determined the permit limits here. Second, the permit will be modified to delete any reference to the other turbines once LPEC selects its model. Therefore, only *one* BACT limit ultimately will be permitted for LPEC's combustion turbines. Essentially, the Region has established separate BACT limits for each of three different potential projects to be built.

Sierra Club's arguments, in effect, pose three questions for the Board: (1) whether the permit's GHG emission limit for the Siemens 4 turbine represents BACT, (2) whether the permit limit for the Siemens 5 turbine represents BACT, and (3) whether the permit limit for the GE turbine represents BACT. Because Sierra Club does not question the BACT permit limit for the Siemens 4 turbine, the questions are narrowed to whether the slightly higher output-based GHG permit limits for the Siemens 5 and the GE turbines represent BACT when considered on their own.[8] The GHG emission level that can be achieved by the Siemens 4 turbine is certainly relevant to these questions, but it is not conclusive, as explained below.

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[6] In contrast, the GE turbine has the lowest permit limits among the three models for total annual emissions and startup emissions. *See* Permit at 7-13.

[7] Pet. at 3 ("Rather than selecting BACT based on the most efficient turbine that meets the applicant's project purpose, the Region set three different limits and allowed the applicant to choose which would apply depending on which turbine design was ultimately installed.").

[8] As noted above, the permit limits for total annual emissions and start-up emissions from the GE turbine are actually lower than the limits for the Siemens 4 turbine.

Thus, the Board need not reach the more general question of whether PSD permits can include "alternate limits" in a single permit.[9]

Sierra Club relies most heavily on its argument that the Region erred in conducting its five-step "top-down" BACT analysis (described in Part VI above) to establish the GHG emission limits for the combustion turbines. *See* Pet. at 12-15. The Board finds that Sierra Club has failed to demonstrate clear error in the Region's BACT analysis.

The Region explained its BACT analysis in its Statement of Basis for the draft LPEC permit. SOB at 8-20. In the first step of its analysis, the Region identified combined cycle combustion turbines with "efficient turbine design" as the most energy efficient way to generate electricity from a natural gas fuel source.[10] RTC at 4; *accord* SOB at 8. In Step 2, the Region determined that this technology is technically feasible. SOB at 11. The Region did not conduct a Step 3 ranking analysis of alternatives because it had identified only one technology option for reducing GHG emissions through energy efficiency in the prior steps of the analysis. *Id.* In Step 4 of its analysis, the Region concluded that there are no energy, environmental or economic impediments to the use of combined cycle combustion technology at the LPEC power plant. *Id.* at 12. Finally, in Step 5 of its analysis, the Region based the GHG emission limits on the highest level of pollution control that it considered to be achievable for the combined cycle combustion turbines at the LPEC facility. *Id*. at 13-20.

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[9] The parties' use of the phrase "alternate limits" reflects and adds to the confusion caused by the Region's approach to the permit in this case, in allowing LPEC to make its final turbine selection after the permit is issued. Evaluating BACT based on three different design and construction scenarios simultaneously poses challenges for the Region in analyzing and explaining its analysis for each limit properly (and separately). It also poses challenges for members of the public seeking to comment on the proposed permit. Further, this approach complicates the permitting process and makes it more difficult to issue the PSD permit in an expeditious time frame. To avoid these problems, the Board suggests that permitting authorities encourage applicants to make the significant decisions affecting final project design before the permit is issued and ideally before the permit is issued for public comment.

[10] The Region also identified carbon capture and sequestration as another technology option for reducing GHG emissions but eliminated that technology from further consideration in Step 4 of its analysis based on economic, energy, and environmental considerations. SOB at 11. Sierra Club does not challenge that determination on this appeal.

To assure that the GHG emission limits established in Step 5 of its analysis represent BACT for combined cycle combustion turbines, the Region compared the energy efficiency (as measured by heat rate) and GHG emission rates of the three proposed LPEC turbine models to the heat rates and GHG emission rates that other PSD permitting authorities have accepted as BACT for eight other facilities using combined cycle combustion technology.[11] *Id*. at 13-14. Permitting authorities typically conduct such a review of comparable sources when assessing appropriate BACT limits. *See NSR Manual* at B.23-24; *In re Pio Pico Energy Center*, 16 E.A.D. 56, 116-17, 130-34 (EAB 2013). The Region concluded that all three turbine models proposed by LPEC are "highly efficient turbines" and that the GHG emission limits selected by the Region are comparable to the emission limits that have been accepted as BACT by other PSD permitting authorities.[12] SOB at 8 and 17.

Sierra Club does not object to the Region's conclusion that combined cycle combustion turbines represent the best available technology for controlling GHG emissions from the LPEC facility. Nor does it disagree with the Region's conclusion that the heat rates and GHG emission levels of the three turbine models proposed by LPEC are within the range that other PSD permitting authorities have established as BACT for other facilities using combined cycle combustion technology. Sierra Club instead contends that the Region erred by failing to conduct its BACT analysis based on a comparison and ranking of the three specific turbine models proposed by LPEC against each other. *See* Pet. At 13-15. Under

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[11] The comparison table provided by the Region in the Statement of Basis expresses the heat rates and GHG emission limits that have been permitted for other facilities using varying measures and operational assumptions. *See* SOB at 13-14. This makes it difficult for readers to compare these limits directly to the limits proposed for the LPEC facility. This presentation presumably reflects differing measures used by the permitting authorities for these other facilities. Nevertheless, the Board encourages permitting authorities to make a greater effort to present and explain their analyses using more consistent measures, by performing the necessary mathematical conversions and obtaining additional information when it is available. Presenting consistent, comparable information is essential for making decisions transparent to the public.

[12] The Region, like other permitting authorities, included a "compliance margin" in the permit limits to allow for design and performance variability and degradation over time of turbine equipment. SOB at 15. These compliance margins, which vary among permitting authorities and specific permits, are included in the emission limits shown in the comparison table. *Id*. at 13-14. Although Sierra Club objected in its public comments that the Region's 12.6% compliance margin in the LPEC permit was excessive, Sierra Club did not raise that objection in this appeal.

Sierra Club's suggested approach, the Region would identify each turbine model as a separate control technology in Step 1, rank the models against each other in Step 3, and select the model with the lowest GHG emission levels (the Siemens 4) as the basis for the output-based BACT emission limit for all three models in Step 5 of the analysis. *See id*.

The Board finds that Sierra Club's suggested method of analysis is not required as a matter of law or EPA policy. Sierra Club's suggested model-specific approach to Steps 1 and 3 of the BACT analysis is not supported by the language or examples used in the NSR Manual and the GHG Permitting Guidance to describe the five-step analytical method. Both these guidance documents suggest that permitting authorities identify general *types* or *categories* of control technologies in Step 1 and rank them against each other in Step 3 based on the emission reduction levels that are achievable for that type of technology. The guidance does not suggest that the analysis should also identify and rank specific equipment *models* that are available for each type of technology considered. *See GHG Permitting Guidance* at 17-18 ("[T]he top-down process calls for all available control *technologies* for a given pollutant to be identified and ranked in descending order of control effectiveness.") (emphasis added), 29 & F-1 (identifying simple cycle and combined cycle combustion technologies as technology options to consider for GHG emissions from natural gas-fired power plants); *NSR Manual* at B.34 (listing wet scrubbers, carbon absorbers, condensers, incineration, electrostatic precipitators, fabric filters and selective catalytic reduction as examples of technology alternatives to consider in BACT analysis for other types of pollutants), B.57-75 (identifying combined cycle and simple cycle gas turbines as control technologies in Step 1).

Therefore, the Board finds no support in EPA's BACT guidance for Sierra Club's position that the three specific turbine models proposed by LPEC must be identified as separate control technologies in the Region's five-step analysis.

The important question here is whether the Region clearly erred or abused its discretion by failing to base the output-based permit limits for the Siemens 5 and GE turbines on the maximum degree of GHG pollution reduction that is achievable at this facility. The Clean Air Act specifies that permitting authorities are required to make BACT decisions "on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs." CAA § 169, 42 U.S.C. § 7479(3). Consistent with this statutory direction, both the Board and EPA guidance have recognized that permitting authorities have discretion to make the case-by-case determinations necessary to establish BACT limits based on the circumstances of a particular facility. *GHG Permitting Guidance* at 17, 20; *NSR Manual* at B.57.

The GHG Permitting Guidance provides the following guidance for determining case-specific BACT limits:

> In determining the appropriate limit, the permitting authority can consider a range of factors, including the ability of the control option to consistently achieve a certain emissions rate, available data on past performance of the selected technology, and specific circumstances of the specific source under review which might affect the range of performance. *In setting BACT limits, permitting authorities have the discretion to select limits that do not necessarily reflect the highest possible control efficiencies but that will allow compliance on a consistent basis based on the particular circumstances of the technology and facility at issue.*

GHG Permitting Guidance at 44 (emphasis added).

The NSR Manual makes clear that permitting authorities are not expected to consider every possible level of control or to impose the highest possible level of control in all circumstances:

> It is not the EPA's intention to require analysis of each possible level of efficiency for a control technique, as such an analysis would result in a large number of options. Rather, the applicant should use the most recent regulatory decisions and performance data for identifying the emissions performance level(s) to be evaluated in all cases.
>
> *** While the most effective level of control must be considered in the BACT analysis, different levels of control for a given control alternative can be considered.
>
> *** In assessing the capability of the control alternative, latitude exists to consider any special circumstances pertinent to the specific source under review.

NSR Manual at B.23-24.

Similarly, the Board has recognized that permitting authorities are not always required to impose the highest possible level of control efficiency but may take case-specific circumstances into consideration in determining what level of control is achievable for a given source. *See, e.g.*, *In re Russell City Energy Ctr.*, 15 E.A.D. 1, 58-61 (EAB 2010) (rejecting a "bright line" test of requiring the highest or average level of control that another source has achieved), *petition denied* *sub nom. Chabot-Las Positas Cmty. Coll. Dist. v. EPA*, 428 F. App'x 219 (9th Cir. 2012); *In re Newmont Nev. Energy Inv., LLC*, 12 E.A.D. 429, 441 (EAB 2005) ("We recently explained that '[t]he underlying principle of all of these cases is that PSD permit limits are not necessarily a direct translation of the lowest emissions rate that has been achieved by a particular technology at another facility, but that those limits must also reflect consideration of any practical difficulties associated with using the control technology.'" (citing *In re Cardinal FG Co.*, 12 E.A.D. 153, 170 (EAB 2005))); *In re Kendall New Century Redev.*, 11 E.A.D. 40, 53 (EAB 2003) (upholding state permitting authority's decision to establish a BACT emission limit at the top of the range of comparable limits at other facilities, based on case-specific distinctions that *included the size of the combined cycle combustion units*); *In re Steel Dynamics, Inc.*, 9 E.A.D. 740, 760 (EAB 2001) ("Thus, while the guidance instructs permit authorities to evaluate the most effective level of control, it also contemplates that those authorities may exercise their discretion in reviewing less effective levels of control").

In this case, the Region has cited two case-specific reasons for declining to impose the somewhat more stringent output-based GHG emission limit of the Siemens 4 turbine model on the Siemens 5 and GE models: (1) the variation in the models' electric generation capacities and (2) the comparability of the GHG emission rates of all three models. Responding to Sierra Club's public comment that the permit limits should be based solely on the Siemens 4 turbine model, the Region explained:

> EPA has determined that BACT for this facility is combined cycle technology with efficient turbine design, and does not agree that each gas turbine model is a different control technique that must be compared against other models, with one model necessarily being chosen over the others. Because the project is defined by the permit applicant as having a production capacity range of 637-753 megawatts (MW) of gross electrical power, EPA has established alternative sets of BACT limits for combined cycle technology that will apply *based on the capacity of the turbine selected by the applicant from among efficient turbine models that have comparable control efficiencies.*

RTC at 4 (emphasis added).

The Region further explained that the marginal variations in efficiency and output-based GHG emission rates among the three turbine models are attributable to the differences in the models' electric generation capacities. *Id*. at 5 ("If each turbine model is operated at maximum capacity, the Siemens [4 and 5] turbines are marginally more efficient because of their higher capacity."). The Region concluded that the GHG emission limits in the permit should vary with the capacity of the particular model in order to achieve the maximum emission reductions that are achievable for each model.[13] *Id.* ("The approach reflected in the permit ensures that the applicant is required to meet the lowest GHG level that is achievable with the turbine that is optimally sized for the particular capacity that the applicant ultimately selects within the size range specified in the application.").

Sierra Club's petition does not specifically challenge the Region's determination that the GHG emission limits included in the permit represent the lowest emission limits that each of LPEC's three proposed models *can* achieve. Rather, Sierra Club suggests that any of the three models will fulfill LPEC's project purpose, and therefore, the permit's output-based emission limits should be based solely on the most efficient model with the lowest output-based GHG emission rate. Pet. at 7-9. At the same time, Sierra Club explicitly states that it does *not* suggest that the Region should compel LPEC to select the Siemens 4 turbine. *Id*. at 14 n.5. Thus, Sierra Club fails to refute the Region's determination that the GHG output-based emission limits in the permit represent the maximum pollutant reductions that are achievable by each of the three turbine models.[14] The Board will defer to this determination, which is based on the Region's technical judgment. *See In re Indeck-Elwood, LLC*, 13 E.A.D. 126, 161 n.67 (EAB 2006) ("[W]here the views of the permit issuer and the petitioner indicate bona fide differences of expert opinion or judgment on a technical issue, the Board typically will defer to the permit issuer.") (internal quotations omitted); *In re NE Hub Partners, LP*, 7 E.A.D. 561, 567-68 (EAB 1998) (same), *review denied sub nom. Penn Fuel Gas, Inc. v. EPA*, 185 F.3d 862 (3d Cir. 1999).

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[13] The Region noted that, if LPEC ultimately desired to supply power at the lower end of the capacity range for business reasons (as appears to be the case here, *see* Oral Arg. Tr. at 11-15), then the marginal efficiency of the larger turbines "would not necessarily be achieved if the permit applicant is required to" oversize the turbine and operate it "at less than its optimal capacity." RTC at 5-6.

[14] Sierra Club also suggested in its public comments and at oral argument that each of the turbine models can achieve a lower emission limit because the Region has allowed an overly generous compliance margin for the permit emission limits. *See* Sierra Club Comments at 6-8; Oral Arg. Tr. at 101-02. Sierra Club did not, however, challenge that compliance margin in its Petition. In addition, Sierra Club suggests that there is no dispute "that if the LPEC applies the [Siemens 4] design, it can achieve a lower emission rate per Megawatt hour than the other two turbine designs." Pet. at 9. Sierra Club does not explain, however, how LPEC could "apply" the Siemens 4 design without actually selecting the Siemens 4 turbine.

The Board also defers to the Region's technical determination that the differences in the GHG emission rates of LPEC's proposed three turbine models are marginal. As noted above, the GHG permit limits for the three models (calculated on a gross output basis) range from 909.2 to 934.5 lb CO_2/MWh, which the Region noted is a variation of only 2.6%. SOB at 16. The range is even narrower when the limits are calculated on a net output basis. *See* RTC at 11 (showing a range from 945.2 to 965.7 lb CO_2/MWh for the three models' BACT limits calculated on a net output basis). The Board calculates the variation in this range as only 2.1%. More significantly, the Region points out that the difference between the output-based emission units for the Siemens 4 turbine and the GE turbine, which LPEC currently plans to select, is only 0.1% when measured on a net output basis.[15] *See* Oral Arg. Tr. at 67 (referring to table in RTC at 11).

The Board concludes, based on this record, that the Region had a rational basis for its determination that all three of the permitted turbine models are "comparably efficient on a performance basis and * * * the assigned BACT limits [are] substantially equivalent except for marginal differences attributable to capacity." Region's Resp. at 5; *accord* RTC at 4-7. In light of their comparable emission levels, the Region takes the position that there is no need to select one of the models over the others in the BACT analysis. RTC at 4-7. The NSR Manual and Board precedent provide some support for this position. The NSR Manual suggests that permitting authorities need not perform a detailed BACT analysis distinguishing between technology alternatives that result in "*essentially equivalent*" or "*identical*" emissions or emission levels with a "*negligible difference*." *NSR Manual* at B.20-21. Citing this provision of the NSR Manual, the Board upheld a permitting authority's decision to eliminate integrated gasification combined cycle ("IGCC") technology from further consideration in the BACT analysis for a coal-fired power plant that was based on a finding that the pollution control efficiency of IGCC technology was comparable to that of another, less expensive technology alternative. *In re Prairie State Generating Co.*, 13 E.A.D. 1, 34-38 (EAB 2006), *aff'd sub. nom Sierra Club v. U.S. EPA*, 499 F.3d 653 (7th Cir. 2007).

[15] PSD permitting authorities have established BACT limits for GHGs based on both net output and gross output measures. *See* SOB at 13-14 (table); *GHG Permitting Guidance* at 37 (suggesting that net output measures may be preferable for some purposes). During the public comment period, Sierra Club suggested that the LPEC permit limits should be based on net, rather than gross, output. The Region explained its reasons for choosing the gross output measure for this permit, *see* RTC at 10-11, and Sierra Club raises no objection to that choice in this appeal.

Based on the record in this case, the Board concludes that the Region did not clearly err or abuse its discretion in determining that the GHG emission limits for all three turbine models represent BACT for highly efficient combined cycle combustion turbines, and that the separate emission limits specified for each of the three models will assure that LPEC minimizes GHG emissions from the combustion turbines regardless of which model it selects. The Region duly considered Sierra Club's comments on this issue, and its explanation of its decision is rational in light of all of the information in the record of this case.

If LPEC proceeds with its plan to select the GE turbine, the Board further notes that this turbine model is the smallest of the three models originally proposed by LPEC and, accordingly, has the lowest total annual GHG emission limit (and startup emission limit).[16] Permit at 13. Therefore, LPEC's current choice of turbine should result in the smallest environmental impact from GHG emissions among the three options it first proposed. *See GHG Permitting Guidance* at 46 ("[S]ince the environmental concern with GHGs is with their cumulative impact in the environment, metrics should focus on longer-term averages.").

B. *Sierra Club Has Not Demonstrated that the Region Abused Its Discretion in Concluding That Adding Solar Technology to the LPEC Facility Would "Redefine the Source"*

The Region did not require LPEC to evaluate solar thermal generating equipment as a potential control option in its BACT analysis for GHGs. *See generally* SOB at 8-11. In commenting on the draft permit, Sierra Club argued that the BACT analysis should have considered the option of solar hybrid technology similar to that used at two other recently permitted facilities. Sierra Club Comments at 18-19; *see also id.* at 11. The Region responded that to do so "would constitute redefining the source." RTC at 21, 37.

On appeal, Sierra Club challenges the Region's conclusion, arguing that, if LPEC used supplemental solar thermal steam, the facility would still be a predominantly gas-fired combined-cycle power plant of the same size and energy production and thus its purpose would not be "redefined." Pet. at 23. Sierra Club also claims that supplemental solar thermal energy in a natural gas combined-cycle generating process is a cleaner production process that has been demonstrated at Palmdale Hybrid Power Project and the Victorville 2 facility and thus should have

[16] The permit's total annual GHG emission limit for the GE turbine is 1,263,055 tons per year ("TPY") carbon dioxide equivalent ("CO_2e"), compared to limits of 1,417,263 and 1,595,712 TPY CO_2e for the two Siemens turbines. Permit at 7, 9, 11.

been considered. *Id*. at 16-20. In its response brief, the Region asserts that it has broad discretion in making "redefining the source" determinations and that, in this case, it properly concluded that a solar preheating option would redefine the source. Region Resp. at 11; *accord* LPEC Resp. at 15.

The Board reviews permitting authorities' determinations that a proposed alternative would "redefine the source" under an abuse of discretion standard. *Russell City*, 15 E.A.D. at 73; *In re Desert Rock Energy Co.*, 14 E.A.D. 484, 526-27, 530, 538-39 (EAB 2009). For the following reasons, the Board concludes that Sierra Club has not demonstrated that the Region abused its discretion in this case.

1. *Relevant Legal Principles: Redefining the Design of the Source*

EPA guidance and Board precedent, affirmed by a federal court of appeals, give permitting authorities the discretion to exclude proposed control alternatives that would constitute a "redefinition of the design of the source" from the BACT analysis for that source. *NSR Manual* at B.13*; GHG Permitting Guidance* at 26; *In re Sierra Pacific Indus.*, 16 E.A.D. 1, 48 (EAB 2013); *In re City of Palmdale*, 15 E.A.D. 700, 728-30 (EAB 2012); *Prairie State*, 13 E.A.D. at 15; *In re Knauf Fiberglass, GmbH*, 8 E.A.D. 121, 136 (EAB 1999). If a permitting authority decides that a proposed alternative would constitute a redefinition of the source, it will not list the alternative as a potential control option in Step 1 of its BACT analysis, and that option will not be considered further. *NSR Manual* at B.13.

EPA generally considers proposed changes to an applicant's proposed primary fuel to be a redefinition of the source. *Id*. (building a natural gas-fired electric turbine in lieu of a coal-fired electric generator not required); *Palmdale*, 15 E.A.D. at 730 (summarizing prior Board cases). The Agency's 2011 GHG guidance acknowledges and reaffirms this principle:

> EPA has recognized that the initial list of control options for a BACT analysis does not need to include "clean fuel" options that would fundamentally redefine the source. Such options include those that would require a permit applicant to switch to a primary fuel type (*i.e.*, coal, natural gas, or biomass) other than the type of fuel that an applicant proposes to use for its primary combustion process. For example, when an applicant proposes to construct a coal-fired steam electric generating unit, EPA continues to believe that permitting authorities can show in most cases that the option of using natural gas as a primary fuel would fundamentally redefine a coal-fired electric generating unit. Ultimately, however a permitting

> authority retains the discretion to conduct a broader BACT analysis and to consider changes in the primary fuel in Step 1 of the analysis.

GHG Permitting Guidance at 27-28.

The 2011 guidance distinguishes the above scenario from the situation in which a permit applicant has already proposed use of a secondary fuel type in its project. *Id.* at 28. In the latter circumstance, the guidance provides:

> [W]hen a permit applicant has incorporated a particular fuel into one aspect of the project design (such as startup or auxiliary applications), this suggests that a fuel is "available" to a permit applicant. In such circumstances, greater utilization of a fuel that the applicant is already proposing to use in some aspect of the project design should be listed as an option in Step 1 unless it can be demonstrated that such an option would disrupt the applicant's basic business purpose for the proposed facility.

Id.[17]

The guidance does not explicitly address a third, intermediate option, which is at issue in the present case: whether a *partial* switch or *supplementation* of the primary fuel with a different type of fuel that the applicant did *not* initially propose as a secondary fuel would constitute a redefinition of the source. To address this issue, the Board reviews the general principles that guide permitting authorities' decisions as to whether a proposed alternative constitutes redefinition of the source.

To determine whether a potential control option would redefine the source, the Board has required permitting authorities to examine first how the applicant defined the proposed facility's "end, object, aim, or purpose," in other words, "the facility's basic design" as described in the application and supporting materials. *Prairie State*, 13 E.A.D. at 22 (footnotes and citations omitted); *accord Sierra Pacific*, 16 E.A.D. at 58. The permit issuer then should take a "hard look" at which design elements are "inherent" to the applicant's purpose and which design elements could possibly be altered to achieve pollutant emissions reductions without disrupting the applicant's "basic business purpose" for the proposed facility. *Sierra Pacific*, 16 E.A.D. at 58; *Desert Rock*, 14 E.A.D. at 530; *Prairie*

[17] Board and Agency case law is consistent with this approach. *See, e.g., Sierra Pacific*, 16 E.A.D. at 50-52 (discussing whether biomass-natural gas mixes, other than the one the applicant proposed, should have been considered); *Palmdale*, 15 E.A.D. at 732 (discussing whether solar power generation beyond that proposed by the applicant should have been considered).

State, 13 E.A.D. at 23, 26. Additionally, the permit issuer must ensure that the proposed facility design was "derived for reasons independent of air quality permitting." *Prairie State*, 13 E.A.D. at 26; *accord Russell City*, 15 E.A.D. at 73; *Desert Rock*, 14 E.A.D. at 530.

The Board has cautioned that permitting authorities should not simply dismiss alternative control options, such as cleaner fuels, as constituting redesign, thereby creating an "automatic BACT off-ramp" from further consideration of the option. *NMU*, 14 E.A.D. at 302. The Clean Air Act specifies that a BACT determination requires a case-by-case analysis. CAA § 169(3), 42 U.S.C. § 7479(3). Thus, permitting authorities must consider the specific circumstances of the situation presented and explain their decisions in the record. *See, e.g., Sierra Pacific*, 16 E.A.D. at 48-50; *Palmdale*, 15 E.A.D. at 732-33.

In *Sierra Pacific* and *Palmdale*, the Board upheld two permitting decisions by EPA Region 9 rejecting suggestions that applicants' proposed fuel choices be modified to reduce GHG emissions, on the grounds that the suggested changes would redefine the design of those sources under the specific circumstances presented in those cases. *Sierra Pacific* involved a lumber manufacturing facility that proposed to use a mix of 10% natural gas and 90% biomass (the facility's excess wood waste) to fuel steam turbines at the facility. The Board upheld the Region's determination that requiring a greater use of natural gas or addition of solar power would be inconsistent with the applicant's primary business purpose of burning its excess wood waste. *Sierra Pacific*, 16 E.A.D. at 48-52. *Palmdale* involved a new hybrid power plant that the applicant proposed to fuel primarily with natural gas, with a supplemental (10%) solar power component added in order to contribute to the State of California's renewable energy goals. The Board upheld the Region's determinations that an all-solar facility would be inconsistent with the applicant's business purpose of providing a baseload supply of electricity[18] and that, based on the record of that case, there was insufficient space at the proposed site to significantly increase the size of the solar energy component in any event. *Palmdale*, 15 E.A.D. at 732-36.

The case-specific justifications for Region 9's "redefining the source" determinations in *Sierra Pacific* and *Palmdale* were essential to the Board's decisions upholding those determinations. The Board did not conclude, as LPEC appears to suggest in the present case, that proposals to add solar power to a power

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[18] As explained in *Palmdale*, a baseload power plant is expected to be able to provide a reliable, continuous supply of electricity, at its full capacity, at all times. 15 E.A.D. at 733.

plant fueled primarily by another fuel source always will constitute a redefinition of the source. *See* LPEC Resp. at 19; Oral Arg. Tr. at 49-50.

The Board's *Palmdale* decision makes clear that technical considerations such as space constraints and geography may be considered by permitting authorities in determining whether suggestions to add or increase the use of supplemental solar power would constitute redesign of the source. *See* 15 E.A.D. at 735-39. Generally, permitting authorities evaluate issues regarding the technical feasibility of a control technology in Step 2, rather than Step 1, of the BACT analysis. *See NSR Manual* at B.17 (suggesting that permitting authorities consider the commercial "availability" and "applicability" of a control technology in Step 2 of the five-step BACT analysis). Technical factors such as the availability of space and the physical location of the facility, however, may also inform a permitting authority's decision whether a proposed use of a different fuel would require redesign of the source. In the case of solar power, for example, if the permitting authority concludes that there are space limitations and/or meteorological concerns such that requiring use of solar panels would essentially require relocation of the entire facility, this conclusion clearly would be important to a Step 1 "redefining the design of the source" analysis.

2. *Case-Specific Analysis*

In determining whether Sierra Club has shown that the Region abused its discretion in concluding that use of solar thermal hybrid technology at the LPEC facility would "redefine the source," the Board reviews both the Region's explanation and the administrative record.

The Region explained its conclusion in two of its responses to public comments. *See* RTC at 21, 37 (responses to comments 16 and 27). In both responses, the Region distinguished between the proposed LPEC facility and previous projects in which the applicant had initially proposed a solar hybrid option. *Id*. More particularly, the Region explained:

> While we acknowledge there may be many ways for solar thermal processes to be integrated with a facility that intends to use steam to generate electricity, we believe that requiring such processes in combination with fossil-fuel combustion would represent the merging of distinct and different source types. While Region 9 required 50 MW of solar energy as part of its BACT determination for the Palmdale Hybrid Power Project NGCC facility, the permit applicant in that case had proposed the solar project as part of its project purpose, which included supporting California's goal of increasing the percentage of renewable energy in the State. Indeed,

> Region 9 specifically explained that it incorporated the solar project into its BACT determination not because it was required to do so, but because doing so was compatible with the permit applicant's goals and would therefore not redefine the source * * *.

Id. at 37; *accord id.* at 21. The Region contrasted the situation at the Palmdale facility from the present one, pointing out that, "[h]ere, LPEC did not include a solar energy component as part of its project in its permit application." *Id*. at 37; *accord id.* at 21 (explaining that the applicant "did not include renewable generation in its project purpose"). In its second response, the Region also referred to potential logistical problems with solar usage at this facility, stating that "the commenter has not explained how LPEC might incorporate such a solar component into its project, or even whether it has or can acquire the land necessary to do so, without redefining the source."[19] *Id*. at 37.

The Region's rationale for concluding that adding solar capacity at the LPEC facility would constitute redesign of the source is not as thorough as the Board would expect, nor does it constitute a "hard look." The Region's explanation comes very close to suggesting that adding supplemental solar power generation is always redesign if the applicant does not propose it in the first place. Such a bright line, "automatic BACT off-ramp" approach is not consistent with the NSR Manual, the GHG Permitting Guidance, or Board precedent, all of which suggest that a case-specific assessment of the situation be made in concluding that a proposed control option would redefine a particular source.

Nevertheless, despite the deficiencies in the Region's explanation, under the facts and circumstances of this case, a remand is not necessary and would not lead to a different result. As the Board reiterated in *In re Steel Dynamics, Inc.*, 9 E.A.D. 165 (EAB 2000), to justify a remand, "there must be a compelling reason to believe that the omissions [by the permitting authority] led to an erroneous permit determination – in other words, that [omissions] materially affected the quality of the permit determination." 9 E.A.D. at 191-92 (quoting *In re Mecklenburg Cogeneration Ltd. P'ship*, 3 E.A.D. 492, 494 n.3 (Adm'r 1990)); *accord Palmdale*, 15 E.A.D. at 735; *In re Three Mountain Power, LLC,* 10 E.A.D. 39, 55 (EAB 2001). Here, upon review of the administrative record, the Board concludes that there is sufficient evidence to support the Region's conclusion that the supplemental solar

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[19] As the Region had stated at the time of the proposed permit, the size of the facility site is, at most, 78 acres. *See* SOB at 29; Jeffrey D. Owens, Intensive Cultural Resources Survey of the Proposed 78-Acre Tract, Harlingen, Cameron County, Texas ("Cultural Resources Survey"), at iii (Dec. 2012) (A.R. II.03); *see also* Revised Application at 15-16 (maps of the site and surrounding area).

option would constitute redesign of the source under the specific circumstances of this case given the business purpose, space limitations, and the specific design requirements of the facility.

The record in this case clearly indicates that it would be logistically difficult for the applicant to incorporate a significant solar component into the facility. The record shows that the site is approximately 78 acres, and at least half of that appears to be utilized by the plant itself and supporting infrastructure. *See* Revised Application at 15-16; *see also* SOB at 29; Cultural Resources Survey at iii; Oral Arg. Tr. at 48-49, 90. As the Board observed in *Palmdale*, generating a significant amount of electric power from solar energy typically requires large acreage for the solar panels. 15 E.A.D. at 736 ("[A] substantial amount of additional acreage would be required to produce a significant amount of additional solar power." (relying on statements of the California Energy Commission)); *accord* Oral Arg. Tr. at 92. For example, in *Palmdale*, the California Energy Commission had estimated that a minimum of eight acres is required to generate one megawatt of electricity. *Palmdale*, 15 E.A.D. at 736. Applying this formula to the acreage of the LPEC facility site suggests that very little solar power could be generated there without either significantly expanding the site or relocating the facility.[20]

The record clearly indicates that relocation would be inconsistent with LPEC's basic business purpose. In its application, LPEC summarized the facility's purpose as the generation of 637 to 735 MW "of gross electrical power near the City of Harlingen in an efficient manner while increasing the reliability of the electrical supply for the State of Texas." Revised Application at 11. LPEC further explained that "[p]ipeline natural gas is chosen as the only fuel for the combustion turbines and duct burner systems due to *local availability of fuel and infrastructure* to support delivery of the fuel to the facility in adequate volume and pressure." *Id*. (emphasis added); *accord* Oral Arg. Tr. at 53. The Region also acknowledged this factor to be an important aspect of the proposed facility's design. *See* RTC at 9. LPEC additionally noted that another "[o]ne of the factors in siting the plant is the *availability of reclaimed water* from the City of Harlingen to be used as cooling water at the plant." Revised Application at 11 (emphasis added); *accord* Oral Arg. Tr. at 53. Because the facility is purposely located near reclaimed wastewater and available natural gas lines and associated infrastructure, relocating it would subvert

[20] For example, assuming that a maximum of 39 acres might be available for installation of a solar array at the site (based on the site plan included in the record) and that a minimum of eight acres is needed to generate one megawatt of electricity from solar power, LPEC would be able to produce only five megawatts of electricity from solar power.

the facility's basic business purpose and design and constitute redesign of the source.

There is also nothing in the record suggesting that LPEC could expand the acreage of the proposed facility in its current location. *See* RTC at 37; Revised Application at 11. Sierra Club has not provided any persuasive evidence or argument indicating otherwise. Sierra Club has merely pointed to two other facilities – Palmdale and Victorville – that have substantially larger acreage that specifically supports their use of solar hybrid technology. *See Palmdale*, 15 E.A.D at 736 (explaining that the facility would use approximately 250 acres to generate 50 MW of power using solar technology); LPEC Resp. Ex. EE at 1-1 (City of Victorville, Application for PSD Permit for Victorville 2 Hybrid Power Project (Apr. 2007)) (same).

The Region's decision not to require LPEC to add a solar component to its facility under these circumstances is consistent with prior Board decisions upholding permitting authorities' discretion to reject options that would redefine the source. *See, e.g., Sierra Pacific*, 16 E.A.D. at 51; *Palmdale*, 15 E.A.D. at 736; *Russell City*, 15 E.A.D. at 74-75 (concluding that permit issuer did not abuse its discretion in determining that dry cooling would redefine the source where facility was initially designed to utilize the city's wastewater, and city transferred land to applicant to allow the facility to be located in that particular location specifically to facilitate use of that wastewater); *Prairie State*, 13 E.A.D. at 28 (concluding that permit issuer's determination that consideration of low-sulfur coal, which would necessarily require use of a fuel source other than the coal at the co-located mine, would require a redefinition of the fundamental purpose or basic design of the proposed mine-mouth facility).

In sum, the business purposes and site-specific constraints described in the administrative record support the Region's conclusion that use of supplemental solar power would constitute redesign of the source under the circumstances of this case.[21] Sierra Club itself, in fact, generally acknowledged that "site-specific

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[21] There is also no suggestion in this case that LPEC purposely avoided use of solar hybrid technology in its proposed design to circumvent BACT analysis or air quality permitting requirements, which, as noted above, is another factor that the Board typically considers. *See Prairie State*, 13 E.A.D. at 26. LPEC's site selection was due to the availability of reclaimed wastewater from the City as well as the availability of natural gas and the infrastructure to support efficient and sufficient delivery of the fuel to the proposed facility. *See* RTC at 9; Revised Application at 11. These considerations are clearly related to efficient energy production and do not suggest in any way that the applicant attempted

considerations" could "preclude the use of solar hybrid technology" at a site in its comments on the draft permit. Sierra Club Comments at 19. Based on the record in this case, the Board concludes that Sierra Club has failed to demonstrate that the Region abused its discretion in concluding that use of solar thermal hybrid technology as a potential control technology for reducing GHG emissions at the facility would "redefine the source."

The Board emphasizes, however, that permitting authorities should include in their Response to Comments a clear and full explanation of any decision to reject comments suggesting the use of a solar component at a proposed facility on the grounds that it would require redefinition of the source. If, as here, a permitting authority's "redefinition of the source" decision is based in part on technical and/or logistical obstacles, it should document the factual basis for its conclusions in the record and explain how the commenter's suggestion would be inconsistent with the facility's basic business purpose (the essential inquiry for a "redefinition of the source" determination). If the permitting authority's decision is based *solely* on technical and/or logistical obstacles to implementing solar options at the proposed facility, the permitting authority should consider whether a Step 2 technical feasibility analysis is needed.

The Board is not suggesting that permitting authorities must perform a full and detailed analysis of all potential solar power options every time a commenter suggests that solar power be considered at a facility. We rejected that suggestion in *Palmdale*, 15 E.A.D. at 734-35 (stating that Region was not required to analyze every possible configuration for increasing the solar power component of a proposed power plant in response to a commenter's very vague and general suggestions). The permitting authority may appropriately tailor the level of analysis to the circumstances presented by the case. Further, the scope of a permitting authority's duty to respond to comments suggesting the addition of solar technology is limited to the extent to which the comment is raised. *See Palmdale*, 15 E.A.D. at 744; *Knauf*, 8 E.A.D. at 147 (explaining that permit issuer may provide general justifications in its responses where commenters raised issues in a general manner). At a minimum, however, the permitting authority should provide a reasoned response to comments that are fairly raised.[22]

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to circumvent Clean Air Act requirements by not including a solar hybrid component in its design.

[22] See, for example, the explanation that the Region provided in its response brief, explaining why the commenter's suggestion in this case was both logistically unworkable at this site and inconsistent with LPEC's business purpose for the facility. Region Resp.

VIII. *CONCLUSION AND ORDER*

For the reasons described above, the Board denies Sierra Club's petition for review of the Region's final permit decision for La Paloma Energy Center, LLC, PSD Permit No. TX-1288-GHG.

So ordered.

at 12-15. The Region could have provided this explanation at an earlier point in the permitting process by including it in its Response to Comments.

MEMORANDUM

SUBJECT: Interpretation of "Begin Actual Construction" Under the New Source Review Preconstruction Permitting Regulations

FROM: Anne L. Idsal
Principal Deputy Assistant Administrator

TO: Regional Air Division Directors

I. Introduction and Purpose of Memorandum

This guidance memorandum addresses how the Environmental Protection Agency (EPA) interprets "begin actual construction" as that term is defined under EPA regulations implementing the major New Source Review (NSR) permitting program.[1] Those regulations provide that "[n]o new major stationary source or major modification to which the requirements of paragraphs (j) through (r)(5) of this section apply shall *begin actual construction* without a permit that states that the major stationary source or major modification will meet those requirements." 40 CFR § 52.21(a)(2)(iii) (emphasis added).[2] The term "begin actual construction" is defined to mean "in

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[1] This guidance is also applicable to minor sources on tribal lands as the federal regulations at 40 CFR § 49.152 adopt a definition of "begin construction" that is consistent with the definition applicable to major sources under 40 CFR § 52.21(a)(2)(iii). In addition, state and local permitting authorities that incorporate the definition of "begin actual construction" referenced in this guidance for their minor NSR programs may apply this guidance to their minor sources at their discretion. Regarding permitting of sources in the Outer Continental Shelf (OCS), EPA's OCS regulations at 40 CFR part 55 establish the applicable requirements, which include federal and state air pollution preconstruction permit requirements. 40 CFR part 55 incorporates by reference the federal Prevention of Significant Deterioration (PSD) rules at 40 CFR § 52.21, as well as applicable state permitting program requirements for OCS Sources located within 25 miles of a state's seaward boundary. The definition of "OCS Source," which is based on activities regulated or authorized under the Outer Continental Shelf Lands Act [43 U.S.C. § 1331 et seq.], is substantially different than the definition of "stationary source" under 40 CFR § 52.21. OCS Sources include activities, equipment, and facilities involved in construction, exploration, transportation and other activities that are not of a permanent nature and may never involve on-site physical construction on an emissions unit. Nothing in this guidance should be construed to allow OCS Sources, including temporary and portable sources, to commence construction and/or operation without an OCS permit pursuant to 40 CFR part 55.

[2] The "requirements of paragraphs (j) through (r)(5)" referenced in 40 CFR § 52.21(a)(2)(iii) are the substantive requirements of the PSD program with which sources are required to comply. For simplicity, this memorandum cites the provisions in the federal PSD regulations at 40 CFR § 52.21, although the other major NSR rules in 40 CFR §

general, initiation of physical on-site construction activities on an emissions unit which are of a permanent nature." 40 CFR § 52.21(b)(11).[3] Under EPA's current interpretation of this regulatory definition, the Agency, as a practical matter, considers almost every physical on-site construction activity that is of a permanent nature to constitute the beginning of "actual construction," even where that activity does not involve construction "on an emissions unit." Consequently, this interpretation tends to preclude source owners/operators from engaging in a wide range of preparatory activities they might otherwise desire to undertake for the purpose of ensuring the project is positioned to move forward in an expedient manner prior to obtaining an NSR permit.

The Agency's current interpretation, which has evolved from various EPA actions described later in this memorandum, is considered by many industry stakeholders to be overly and unnecessarily restrictive. Some have asserted that, due to this interpretation, projects have been delayed and efforts to engage in construction pursuant to staged schedules (*e.g.*, which seek to take account of seasonal conditions in cold-weather areas) have been frustrated. A number of stakeholders, in submitting comments in response to the *Federal Register* notice titled, "Evaluation of Existing Regulations," EPA-HQ-OA-2017-0190, 82 FR 17793 (April 13, 2017), specifically identified EPA's interpretation of "begin actual construction" as an important matter the Agency should reconsider.[4]

Upon review, EPA has determined that its current interpretation of the term "begin actual construction" for the major NSR program does not entirely comport with the plain language of the long-standing regulatory definition of that term. Accordingly, EPA is adopting a revised interpretation that better conforms to the regulatory text. Under EPA's revised interpretation, a source owner or operator may, prior to obtaining an NSR permit, undertake physical on-site activities – including activities that may be costly, that may significantly alter the site, and/or are permanent in nature – ***provided*** that those activities do not constitute physical construction ***on an emissions unit***, as the term is defined in 40 CFR § 52.21(b)(7).[5] Further, under this revised interpretation, an "installation necessary to accommodate" the emissions unit at issue is *not* considered part of that emissions unit, and those construction activities that may involve such

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51.166, 40 CFR § 51.165, and Appendix S of 40 CFR part 51 contain provisions that set forth essentially identical definitions of the term "begin actual construction." *See* 40 CFR § 51.166(b)(11); 40 CFR § 51.165(a)(1)(xv); 40 CFR part 51, Appendix S II.17. EPA interprets the preconstruction review requirements in those regulations consistent with the requirements of 40 CFR § 52.21, and hence the statements in this memorandum apply to those provisions as well.

[3] The definition continues: "Such activities include, but are not limited to, installation of building supports and foundations, laying underground pipework and construction of permanent storage structures. With respect to a change in method of operation, this term refers to those on-site activities other than preparatory activities which mark the initiation of the change." 40 CFR § 52.21(b)(11).

[4] EPA published the April 13, 2017, *Federal Register* notice as directed by Executive Order 13777, "Enforcing the Regulatory Reform Agenda." The Department of Commerce also received a number of comments concerning EPA's interpretation of "begin actual construction" in response to the Department's own request for information entitled "Impact of Federal Regulations on Domestic Manufacturing," Docket No. 170302221-7221-01, 82 FR 12786 (March 7, 2017). The Department had been directed to initiate this request by the presidential memorandum of January 24, 2017, "Streamlining Permitting and Reducing Regulatory Burdens for Domestic Manufacturing." These stakeholder comments are discussed in more detail below.

[5] "Emissions unit" is defined as "any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant..." 40 CFR § 52.21(b)(7).

"accommodating installations" may be undertaken in advance of the source owner or operator obtaining a major NSR permit.

EPA recognizes that the interpretation at issue was a long-standing one and the Agency does not take lightly the decision to revise it. Accordingly, Part II of this memorandum provides a thorough review of the statutory and regulatory background, along with the history of EPA's application of the prior interpretation. Part III sets forth EPA's revised interpretation, explains why the revised interpretation is consistent with the regulatory text, and gives the Agency's reasons for adopting it. In Part IV, EPA addresses certain matters related to the issue of determining the proper scope of an "emissions unit," which is an issue of particular importance in light of the Agency's revised interpretation of "begin actual construction."

II. Background

A. The Clean Air Act

Congress in the Clean Air Act (CAA or the Act) Amendments of 1977 established the NSR program to be a preconstruction permitting program, a program by which a source owner or operator must obtain a permit prior to constructing a major stationary source (or making a "major modification" to an existing major stationary source).[6] Generally speaking, before a permit to construct can be issued, an analysis must be performed to ascertain the effects that projected emissions from the proposed new facility (or, as may be the case, the proposed "modified" facility) are expected to have on air quality. The permit must also specify the emission limits that the proposed new facility or modified facility will be required to meet for the air pollutants of concern, with those limits being based on a determination of the "best available control technology" (under the PSD program) or the "lowest achievable emission rate" (under the nonattainment NSR program).

While Congress in the 1977 CAA Amendments specified that, for any "major emitting facility on which construction is commenced after August 7, 1977," such facility could not "be constructed . . . unless . . . a permit has been issued," the CAA contains no provision that expressly identifies or defines what constitutes the "construction" of a source, or that specifically establishes the point at which a source can be considered to have been "constructed."[7] Nor does the Act contain

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[6] *See* 42 U.S.C. § 7475(a); CAA § 165(a) ("No major emitting facility on which construction is commenced after August 7, 1977, may be constructed in any area to which this part applies unless . . . a permit has been issued for such proposed facility."); 42 U.S.C. § 7502(c)(5); CAA § 172(c)(5) ("Such plan provisions shall require permits for the construction and operation of new or modified major stationary sources anywhere in the nonattainment area."). Preconstruction PSD permits cover major sources or major modifications in attainment or unclassifiable areas and emissions of National Ambient Air Quality Standards (NAAQS) pollutants and other regulated pollutants. Preconstruction nonattainment NSR permits cover major sources or major modifications in nonattainment areas and emissions of those nonattainment NAAQS. This memorandum uses the term "NSR" to refer to both the PSD program and the nonattainment NSR program.

[7] In enacting the 1977 CAA Amendments, Congress initially failed to include a statutory definition for the term "construction." Congress also failed to apply the requirements of the PSD program to major sources that underwent modification. In an effort to correct this oversight, Congress, through a post-enactment technical amendment – *i.e.*, Pub. L. No. 95-190, 91 Stat. 1402 (November 16, 1977) – added section § 169(1)(C) to the Act, providing a

any provision that directly establishes when physical on-site "construction" activities can be said to have begun.[8] Accordingly, it was left to EPA's discretion, in adopting implementing regulations for the then-new NSR program, to give meaning to these terms through regulatory definitions.

B. EPA's Initial NSR Implementing Regulations

In June 1978, EPA promulgated implementing regulations for the PSD program enacted by the 1977 CAA Amendments.[9] Those rules contained a "source applicability" provision that specified that "[n]o major stationary source or major modification shall be *constructed* unless the requirements of paragraphs (j) through (r) of this section, as applicable, have been met." 40 CFR § 52.21(i)(1) (1978) (emphasis added); 43 FR 26406. While the 1978 PSD rules contained no definition of the term "constructed," the term "construction" was defined to mean "fabrication, erection, installation, or modification of a source." *Id.* § 52.21(b)(7) (1978); 43 FR 26404. The term "source" was defined to mean "any structure, building, facility, equipment, installation, or operation (or combination thereof) which is located on one or more contiguous or adjacent properties and which is owned or operated by the same person (or by persons under common control)." *Id.* § 52.21(b)(4) (1978); 43 FR 26404.

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definition for "construction." Even then, Congress only managed to clarify that "construction" *included* "modification," and still failed to define "construction" itself. *See* 42 U.S.C. § 7479(2)(C) ("The term 'construction' when used in connection with any source or facility, includes the modification (as defined in section 7411(a) of this title) of any source or facility.").

[8] Congress did not intend for the requirements of its new statutory PSD program to apply to either (i) those sources in existence as of the date of enactment of the 1977 CAA Amendments (*i.e.*, August 7, 1977); nor to (ii) those sources, the "construction" of which had already "commenced" as of that date. In colloquial terms, such sources were to be considered "grandfathered." For purposes of determining whether a source owner or operator was sufficiently committed to the construction of a particular source at a particular site, so that its under-construction facility would qualify for this "grandfathered" status, Congress provided a definition for the term "commenced." *See* 42 U.S.C. § 7479(2)(A) (The "term 'commenced' as applied to construction of a major emitting facility means that the owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations," and either has "(i) begun, or caused to begin, a continuous program of physical on-site construction of the facility" or has "(ii) entered into binding agreements or contractual obligations, which cannot be canceled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed within a reasonable time."). The PSD regulations contain substantially the same definition of "commence" (*e.g.*, 40 CFR § 52.21(b)(9)), and that definition is used both in implementing the statutory grandfathering provisions described above (*see* 40 CFR § 52.21(i)(1)(i) – (v)) and also in determining those circumstances under which a PSD permit may become invalid (*see* 40 CFR § 52.21(r)(2), which provides, in relevant part, that "approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval …"). While the term "commence construction" is sometimes used in place of the regulatory term "begin actual construction," each term speaks to a different concept, and the two terms are not interchangeable. The term "commence" does not speak to what sorts of on-site "construction" activities require a permit *before* they can be undertaken. Rather, the term "commenced" is meant to identify the nature and extent of the construction activity a source owner or operator must have engaged, *after* having obtained "all necessary preconstruction approvals or permits," in order for the source under construction to warrant "grandfathered" status or to avoid invalidation of an issued PSD permit.

[9] *See* 43 FR 26380 (June 19, 1978) (40 CFR part 51); 43 FR 26388 (June 19, 1978) (40 CFR part 52) (collectively, the 1978 PSD rules). The first set of rules implementing the nonattainment NSR program enacted by the 1977 CAA Amendments were promulgated in January 1979. *See* 44 FR 3274 (January 16, 1979).

In neither the regulatory text nor in the accompanying preamble to the 1978 PSD rules did EPA provide an explanation of the phrase "shall be constructed." Moreover, the Agency did not identify what sort of physical on-site construction activities a source owner or operator could permissibly undertake prior to receiving a preconstruction permit.[10] It fell therefore to EPA to explicate this regulatory provision through interpretive guidance. By the end of 1978, EPA had done so. *See* Memorandum, Edward E. Reich, Director, U.S. EPA Division of Stationary Source Enforcement, to U.S. EPA Enforcement Division Directors, Regions I-X (December 18, 1978) (the December 1978 Reich Memorandum).

C. EPA's Initial Guidance

In the December 1978 Reich Memorandum, EPA framed the issue as "where on the continuum from planning to operation of a major emitting facility does a company or other entity violate the PSD regulations if it has not yet received a PSD permit." December 1978 Reich Memorandum at 1. "This question has arisen several times in particular cases," EPA stated, and "general guidance now appears necessary." *Id.*[11] EPA went on to note that the "statute and regulations do not answer this question." *Id.* Thus, the Agency stated, the "term 'constructed' seems to be open to further interpretation by EPA." *Id.*

EPA then announced that it was abandoning what it described as its prior approach of "mak[ing] the determination on a case-by-case basis, after considering all the facts of the individual situation," in favor of a "new policy," under which "certain limited activities will be allowed in all cases." December 1978 Reich Memorandum at 2. "These allowable activities," EPA stated, are "planning, ordering of equipment and materials, site-clearing, grading, and on-site storage of equipment and materials." *Id.* EPA added that "[a]ny activities undertaken prior to issuance of a PSD permit would, of course, be solely at the owner's or operator's risk." *Id.* At the same time, the Agency continued, "[a]ll on-site activities of a permanent nature aimed at completing a PSD source for which a permit has yet to be obtained are prohibited under all circumstances." *Id.* "These prohibited activities," EPA explained, "include installation of building supports and foundations, paving, laying of underground pipe work, construction of permanent storage structures, and activities of a similar nature." *Id.*

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[10] The 1978 PSD rules did not expressly preclude an owner or operator from engaging in any particular on-site construction activity prior to obtaining a PSD permit. The terminology employed by the "source applicability" provision of the 1978 PSD rules – *i.e.*, ". . . shall be constructed unless the requirements of paragraphs (j) through (r) have been met" – established a preconstruction permit program only by implication.

[11] One such "particular case" had been addressed by EPA two months earlier. *See* Memorandum, Edward E. Reich, Director, U.S. EPA Division of Stationary Source Enforcement, to Thomas W. Devine, Chief Air Branch, U.S. EPA Region I (October 10, 1978) (the October 1978 Reich Memorandum). Responding to a request for "guidance on the extent to which a company can legally construct, prior to PSD permit issuance, a building which will house both PSD-affected and non-PSD affected facilities," EPA said that, "[i]n general, a structure which is to house independent facilities, some of which are subject to PSD and some of which are not, may be constructed before a PSD permit is issued only if the building is a necessary part of the PSD-exempt project and if it is in no way modified to specifically accommodate the PSD-affected facilities." October 1978 Reich Memorandum at 1. In the specific case of certain "diesel engines . . . subject to PSD review," EPA continued that, "[a]lthough drains, diesel footings, and various other installations may be considered part of the structure of the building," those elements of the project "may not be constructed until the permit is issued if they are specific to the diesel engines." *Id.*

EPA suggested that this "new policy" would have "several advantages," anticipating that it would be "easy to administer, since case-by-case determinations will not be required." December 1978 Reich Memorandum at 2. Further, EPA stated, it "assures national consistency and permits no abuse of discretion." *Id.* "Finally," the Agency opined, "it appears to be the most legally correct position." *Id.*[12]

The 1978 PSD implementing rules were subsequently challenged by various parties. Those challenges were resolved by the U.S. Court of Appeals for the District of Columbia Circuit in *Alabama Power Co. v. Costle*, 636 F.2d 323 (D.C. Cir. 1979). The 1978 rules were upheld in part, while certain provisions were struck down.[13] Subsequently, on remand, EPA extensively revised its NSR rules. *See* 45 FR 52676 (August 7, 1980) (the 1980 NSR rules).

D. The 1980 NSR Rules

EPA, in the 1980 NSR rules, made four changes to the NSR preconstruction permitting provisions that are relevant here. First, EPA revised the "source applicability" provision to read: "No stationary source or modification to which the requirements of paragraphs (j) through (r) of this section apply shall *begin actual construction* without a permit which states that the source or modification would meet those requirements." 40 CFR § 52.21(i)(1) (1980) (emphasis added); 45 FR 52738. In other words, it was here that EPA explicitly incorporated into those rules the term "begin actual construction."[14]

Second, EPA adopted a definition of "begin actual construction." As promulgated in 1980, the definition read then the same as it does today. 40 CFR § 52.21(b)(11) (1980); 45 FR 52736.

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[12] EPA provided no explanation for why it believed this approach reflected the "most legally correct position." EPA acknowledged that the "statute and regulation do not answer this question" of "where on the continuum from planning to operation of a major emitting facility does a company . . .violate the PSD regulations if it has not yet received a PSD permit." December 1978 Reich Memorandum at 1. The CAA itself, EPA noted, "states simply that, '[n]o major emitting facility . . . may be constructed . . . unless – (1) a permit has been issued.'" *Id.*, *quoting* 42 U.S.C. § 7475(a). Further, EPA observed, while the term "commenced" was "quite specifically defined in . . . Section 169(2)(A) of the Clean Air Act" (and, as well, in 40 CFR § 52.21(b)(8)), that term served only the "purpose of deciding the threshold question of the applicability of the PSD regulations." *Id.* at 2. *See* note 8, above. EPA also recognized that the 1978 PSD rules themselves did "not explicitly answer the question" at hand. *Id.* Thus, EPA understood that, given the lack of statutory and regulatory direction in this matter, the Agency possessed considerable discretion – *i.e.*, "[W]e are not bound by [the statutory and regulatory definitions of "commencement of construction"] in deciding what activities may be conducted prior to receiving a necessary PSD permit." *Id.* But EPA did not otherwise explain its position that, in exercising this discretion, the Agency had arrived at the "most legally correct position."

[13] Nothing in the *Alabama Power Co.* decision speaks directly to the issues addressed by this memorandum. The court did, however, strike down the 1978 PSD rules' definition of "source" set forth in 40 CFR § 52.21(b)(4). The D.C. Circuit found that, because Congress had in CAA § 111(a)(3) expressly defined "stationary source" to mean "any building, structure, facility, or installation which emits or may emit any air pollutant," the Agency had erred by including in its regulatory definition of "source" the additional elements "equipment," "operation," and "combination thereof." *See Alabama Power Co.*, 636 F.2d at 395-396.

[14] The equivalent provision in the current NSR rules (*i.e.*, 40 CFR § 52.21(a)(2)(iii)) was recodified in conjunction with the promulgation of the NSR reform rules in 2002. *See* 67 FR 80275 (December 31, 2002).

Third, EPA introduced in the NSR rules another new term ("emissions unit"), which it defined as "any part of a stationary source which emits or would have the potential to emit any pollutant subject to regulation under the Act." 40 CFR § 52.21(b)(7) (1980); 45 FR 52736. The term "emissions unit" was used in various places throughout the 1980 NSR rules, including in the definition of "begin actual construction" – *i.e.*, "in general, initiation of physical on-site construction activities on an *emissions unit* which are of a permanent nature." 40 CFR § 52.21(b)(11) (1980) (emphasis added); 45 FR 52736.

Fourth, EPA revised the definition of "construction." The revised definition provided that the term "means any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) which would result in a change in actual emissions." *Id.* § 52.21(b)(8) (1980); 45 FR 52736. In equating "construction" to a "physical change" which would result in a "change in actual emissions," this revision reflected the 1980 NSR rules' shift to the use of "actual emissions" in determining post-change emission increases.[15] In revising the definition, EPA also substituted the newly-introduced term "emissions unit" for "source," which had been used in the 1978 PSD rules' definition of "construction."[16]

E. EPA Guidance on "Begin Actual Construction"

When it first promulgated the term "begin actual construction" as part of the 1980 NSR rules, EPA did not in the preamble to those rules discuss its purpose for having done so. Nor had the Agency originally proposed to adopt that term.[17] Rather, the new term, as defined at 40 CFR § 52.21(b)(11), appeared for the first time, without explanation, in the final rule. Thus, it was again left to the Agency to explain its approach to determining when a source "begin[s] actual construction" through subsequent guidance. In a memorandum issued in March 1986, EPA had occasion to interpret the new regulatory term "begin actual construction." *See* Memorandum,

[15] The 1978 PSD rules had specified that a "major modification" was "any physical change in, change in the method of operation of, or addition to a stationary source which increases the *potential emission rate* of any air pollutant regulated under the [A]ct . . . ." 40 CFR § 52.21(b)(2) (1978) (emphasis added). In the 1980 NSR rules, EPA adopted an "actual emissions" approach, citing the D.C. Circuit's *Alabama Power Co.* decision. *See* 45 FR 52700 ("Following the lead of the court, EPA has also shifted the focus of its regulatory definitions from 'potential to emit' to 'actual emissions.'"). In 2002, EPA again revised the term "construction" by removing the word "actual," so that the regulatory definition now concludes ". . . which would result in a change in emissions." *See* 67 FR 80276 (December 31, 2002). In doing so, EPA explained that the "change was necessary because of how the definition of 'actual emissions' is used in the final rule" that the Agency was at that time adopting, but that "the deletion is not intended to change any meaning in the term 'construction.'" *Id.* at 80190.

[16] EPA in 1980 also replaced the defined term "source" (as had been used in the 1978 PSD rules) with the term "stationary source." In so doing, EPA removed the elements "equipment," "operation," and "combination thereof" that had appeared in the old definition of "source," which elements the D.C. Circuit in the *Alabama Power Co.* decision had found to be unlawful. *See* note 13, above; *see also* 40 CFR § 52.21(b)(5) (1980); 45 FR 52736 (defining "stationary source" to mean "any building, structure, facility, or installation which emits or may emit any pollutant subject to regulation under the Act.").

[17] *See* 44 FR 51924 (September 5, 1979). As the "source applicability" provision (*i.e.*, 40 CFR § 52.21(i)) was proposed in 1979 to be revised, it provided: "(1) No stationary source or modification to which the requirements of paragraphs (j) through (u) of this section apply *shall be constructed* without a permit that states that the stationary source or modification would meet those requirements." *Id.* at 51953 (emphasis added).

Edward E. Reich, Director, U.S. EPA Division of Stationary Source Compliance, to Robert R. DeSpain, Chief, Air Programs Branch, EPA Region VIII (March 28, 1986) (the 1986 Reich Memorandum).

1. The 1986 Reich Memorandum

This being the first guidance statement on "begin actual construction" since issuing the 1980 NSR rules, EPA began by pointing back to the December 1978 Reich Memorandum and stating that the "question of what type of construction activities may be conducted prior to issuance of a PSD permit" had already "been covered by EPA policy for many years." 1986 Reich Memorandum at 2. This "policy statement from 1978," the 1986 Reich Memorandum announced, continued to represent EPA's "policy on the types of construction activities which are prohibited, or may occur at risk to the owner prior to issuance of a PSD permit." *Id.* at 3.

Such activities, EPA explained, included "planning, ordering of equipment and material, site-clearing, grading, and on-site storage of equipment and materials." *Id.* at 2. Meanwhile, "[a]ll on-site activities of a permanent nature aimed at completing a PSD source (including, but not limited to, installation of building supports and foundations, paving, laying of underground pipe work, construction of permanent storage structures, and activities of a similar nature)," the Agency said, "are prohibited until the permit is obtained, under all circumstances." *Id.*

The continuation of these elements of the 1978 policy was supported by the fact that EPA had used language from the 1978 memo in the definition of "begin actual construction."[18] But in other parts of the 1986 memo, EPA also identified a need to give meaning to language in the definition of "begin actual construction" that was not reflected in the 1978 memo, particularly, the use of the term "emissions unit." EPA recognized that it would now be necessary to draw a distinction between a "major stationary source" on the one hand and an "emissions unit" on the other, insofar as an emissions unit is, by definition, a *part* of a stationary source. *Id.* ("[A]lthough applicability of PSD is determined on a source-wide basis, it may become necessary to distinguish the emissions unit from the major stationary source or modification in order to determine at what point in construction planning or construction activities a PSD permit is required."). Notwithstanding this observation in the 1986 memo, EPA continued to use the term "PSD source," rather than "emissions unit." EPA also stated that "[l]anguage changes in the regulations" – *i.e.*, the adoption of the defined term "begin actual construction" by the 1980 NSR rules – "after [the

[18] For example, the December 1978 Reich Memorandum had stated: "All *on-site activities of a permanent nature* aimed at completing a PSD source for which a permit has yet to be obtained are prohibited under all circumstances." December 1978 Reich Memorandum at 2 (emphasis added). *Cf.* 40 CFR § 52.21(b)(11) (". . . initiation of physical *on-site* construction *activities* on an emissions unit which are *of a permanent nature*." (emphasis added)). Further, the December 1978 Reich Memorandum had provided as examples of "prohibited activities" such things as the "installation of building supports and foundations, paving, laying of underground pipe work, construction of permanent storage structures, and activities of a similar nature." December 1978 Reich Memorandum at 2. The second sentence of 40 CFR § 52.21(b)(11) uses much the same language. In a letter dated some eight months after promulgation of the 1980 NSR rules, EPA suggested that the definition of "begin actual construction" had been "based upon Mr. Reich's December 18, 1978 memorandum," in that it "was intended to embody in regulatory form the Agency's policy that site preparation activities do not trigger Federal PSD requirements." *See* Letter from Valdas V. Adamkus, Acting Regional Administrator, EPA Region V, to Joseph M. Polito, Honigman, Miller, Schwartz and Cohen (April 29, 1981) at 2.

1978 Reich Memorandum] was issued did not alter EPA's interpretation of what a source may do prior to obtaining a PSD permit." *Id.* at 3.

However, when interpreting the term "emissions unit," the 1986 memo added something to the policy that had not been reflected in the 1978 memo. EPA stated that, as used in the definition of "begin actual construction," the term "emissions unit" should be construed to "include any installations necessary to accommodate that unit." 1986 Reich Memorandum at 2. EPA continued by stating that "if the emissions unit (including any accommodating installation) is an integral part of the source or modification (i.e., the source or modification would not serve in accordance with its original intent, except for inclusion of the emissions unit) the PSD permit must be obtained before construction on the entire source commences." *Id.* at 2-3.

The interpretation of "begin actual construction" set forth in the 1986 Reich Memorandum would remain the Agency's interpretation until now. Over that time, EPA has reiterated and elaborated upon the interpretation, both in other guidance documents, and in providing direction to states and to the Regions in the form of applicability determinations.

2. The 1993 Rasnic Memorandum

In April 1993, EPA was asked by the then-Region III air enforcement branch chief to provide its opinion about the applicability of the PSD program to "certain Georgia-Pacific activities at a site in West Virginia." *See* Memorandum, John B. Rasnic, Director, U.S. EPA Stationary Source Compliance, Office of Air Quality Planning and Standards, to Bernard E. Turlinski, Chief, Air Enforcement Branch, EPA Region III (May 13, 1993) (the 1993 Rasnic Memorandum) at 1. In responding, EPA concluded that "the activities as described by Georgia-Pacific . . . are construction activities prohibited prior to issuance of a PSD permit." *Id.* To reach that conclusion, EPA looked to the 1986 Reich Memorandum, which it cited as support for its position that "[i]f the construction activity is an integral part of the PSD source or modification," the source "must obtain a PSD permit" prior to undertaking that construction. *Id.* at 1-2.

EPA further stated that the NSR rules "prohibit any construction activities that are of a permanent nature related to the specific project for which a PSD permit is needed," as opposed to "general construction not related to the emission unit(s) in question, prior to receipt of a construction permit." 1993 Rasnic Memorandum at 2. "This standard," EPA stated, "prohibits activities in a permanent way that the source would reasonably undertake only with the intended purpose of constructing the regulated project." *Id.*

3. The 1993 Howekamp Memorandum

In November 1993, EPA Region IX issued an internal memorandum the purpose of which was to "reiterate[] EPA's longstanding interpretation concerning the range of construction related activities that lawfully may occur prior to the issuance of a permit to construct or modify a facility or emissions unit." Memorandum, Dave Howekamp, Director, Air and Toxics Division, EPA Region IX, to all Region IX Air Agency Directors and NSR Contacts (November 4, 1993) (the 1993 Howekamp Memorandum). The memorandum explained that the "question of what type of preliminary site activities may be conducted prior to permit issuance" had already been "addressed by EPA policy memoranda on December 18, 197[8], March 28, 1986, and May 13, 1993." 1993 Howekamp Memorandum at 1.

"These memoranda," EPA stated, "explain that certain limited activities that do not represent an irrevocable commitment to the project would be allowed, such as planning, ordering of equipment and materials, site clearing, grading, and on-site temporary storage of equipment and materials." *Id.* EPA cautioned, however, that "all on-site activities of a permanent nature aimed at completing construction" of the "source including but not limited to installation of building supports and foundations, paving, laying of underground pipe work, construction of any permanent storage structure, and activities of a similar nature are prohibited until after the permit is issued and effective, under all circumstances." *Id.* at 2.

4. The 1995 Seitz Letter

In December 1995, EPA responded to a request from the Minnesota Pollution Control Agency (MPCA) for "clarification . . . concerning the scope of construction-related activities that may occur prior to issuance" of a PSD permit "under the Federal regulations at 40 CFR 52.21, which are also incorporated into Minnesota's rules." Letter from John S. Seitz, Director, EPA Office of Air Quality Planning and Standards, to Charles W. Williams, Commissioner, Minnesota Pollution Control Agency (December 13, 1995) (the 1995 Seitz Letter) at 1. The MPCA had indicated that it "interprets the Federal PSD rules to not prohibit site clearing activities prior to receiving a PSD permit, but that there is a prohibition on beginning construction activities that are of a permanent nature." *Id.* at 2.

In response, EPA said that it "agree[d] with Minnesota that site clearing and grading are not prohibited" by the regulatory definition of "begin actual construction." 1995 Seitz Letter at 2. EPA added that "[a]llowed preconstruction activities would also include ordering materials and temporary storage on site." *Id.*, *citing* 1986 Reich Memorandum. Conversely, EPA stated, "[p]rohibited (permanent and/or preparatory) preconstruction activities . . . would include any construction that is costly, significantly alters the site, and/or [is] permanent in nature." *Id.* at 2. It was "EPA's longstanding policy," the Agency represented, citing the 1986 Reich Memorandum, "that section 52.21(i) reasonably prohibits any preconstruction 'intended to accommodate' an 'emissions unit' or which is an 'integral part of the source or modification.'" *Id.*

The MPCA had also inquired of EPA "whether there is flexibility under the Clean Air Act . . . or rules to allow construction of footings for emissions units without a PSD permit in cold weather States such as Minnesota." 1995 Seitz Letter at 3. In response, EPA stated that its "general view is that such an exemption is not authorized under the Act or the Federal PSD rules." *Id.*

5. Other Agency Statements

In 1996, EPA proposed numerous changes to its NSR rules. 61 FR 38250 (July 23, 1996). At that time, the Agency took note of the fact that "[s]everal industry members" of the Clean Air Act Advisory Committee's Subcommittee on NSR Reform had "recommended that EPA change the NSR regulations to enable sources to engage in a broader range of activities prior to receipt of an NSR permit in cases involving modifications to existing sources." 61 FR 38270. These members, EPA stated, had "asserted that it was unnecessary and inappropriate to prohibit preliminary activities to achieve the statutory purpose of requiring a permit before construction begins," and that "such prohibitions caused delay and added expense for no good purpose." *Id.* Recognizing that there was a "wide difference of opinion on these issues," EPA solicited comment on the matter. *Id.*

To "assist in formulating comments," EPA then set forth a summary of its own position, in which the Agency stated that the CAA "plainly bars construction without a permit," and that it was "clear that core activities at an industrial site, such as the fabrication or installation of pollution-generating equipment, constitute 'construction' within the meaning of the Act." 61 FR 38270-71. "At the same time," EPA acknowledged, "the statute does not address the details of the construction process, nor does it constrain EPA's discretion to fashion regulatory mechanisms to harmonize the needs of environmental protection and economic growth in a manner consistent with the legislative purpose." *Id.* at 38271. In the case of "begin actual construction," the Agency concluded, the "regulations and EPA's longstanding policy clearly identify the scope of prohibited preconstruction activities," and those "current regulations and policies" would "remain in effect regardless of today's request for comment." *Id.*

Having summarized its position, EPA then solicited comment on "whether there exists a significant problem with the current system," and, if so, "whether a broader range of preliminary activities should be allowed prior to the issuance of a final NSR permit." *Id*. In particular, EPA asked for comment "regarding the need for potential changes to the current regulations that would allow greater flexibility with respect to construction activities in the case of a proposed modification to the source," while at the same time "preserving the essential characteristics of a preconstruction review program." *Id.*

Ultimately, however, when EPA took final action in 2002 to promulgate the NSR reform rules, the Agency made no changes to the definition of "begin actual construction" in 40 CFR § 52.21(b)(11) with no explanation for its having declined to do so. *See generally* 67 FR 80186. To date, the July 1996 preamble discussion has been the most recent significant discussion on EPA's part regarding its approach to applying the term "begin actual construction" under the NSR rules.

III. Discussion

After careful consideration, EPA is adopting a revised interpretation of "begin actual construction," as that term is defined in 40 CFR § 52.21(b)(11) and used in 40 CFR § 52.21(a)(2)(iii). EPA has determined that the interpretation of "emissions unit" set forth in the 1986 Reich Memorandum and reiterated in subsequent Agency guidance is not the best reading of the relevant regulatory text because it fails to give meaning to the distinction between an emissions unit and a major stationary source. Going forward, therefore, EPA will be applying the revised interpretation set forth in this memorandum.

Under EPA's revised interpretation, a source owner or operator may, prior to obtaining an NSR permit, undertake physical on-site activities – including activities that may be costly, that may significantly alter the site, and/or are permanent in nature – ***provided*** that those activities do not constitute physical construction ***on an emissions unit***, as the term is defined in 40 CFR §

52.21(b)(7). Further, under this revised interpretation, and in contrast to the 1986 Reich Memorandum, an "installation necessary to accommodate" the emissions unit at issue is *not* considered part of that emissions unit,[19] and construction activities that involve an "accommodating installation" may be undertaken in advance of the source owner or operator obtaining an NSR permit.

In conjunction with its adoption of this revised interpretation of the term "begin actual construction," EPA no longer intends to follow the interpretation of "begin actual construction" reflected in the 1986 Reich Memorandum, the 1993 Howekamp Memorandum,[20] and the 1995 Seitz Letter. While prior interpretations failed to apply this distinction between the 1980 and 1978 PSD rules, this guidance adopts an interpretation of the term "begin actual construction" that gives meaning to the added term "emissions unit."

EPA notes that it remains the case, as had been true under prior Agency guidance, that where a prospective source owner or operator chooses to undertake on-site construction activities prior to obtaining an NSR permit, as may be permitted under this revised interpretation, the owner or operator does so at their own risk. That is, the prospective source owner or operator must recognize that the resources (*e.g.*, time, money) expended in undertaking such construction may be wasted should the owner or operator be required to re-do or revise work already completed in order to obtain a permit or should it ultimately be the case that no permit is issued or if the permit review agency determines that design changes (*e.g.*, stack height, emission unit location, etc.) are needed to assure compliance with the National Ambient Air Quality Standards (NAAQS) and increment. A source cannot use the equity and resources expended to claim cost infeasibility or otherwise influence the Best Available Control Technology (BACT) determination or the decision to grant the permit. In addition, an owner/operator should also be mindful that some on-site activities prior to obtaining a PSD permit could be limited by other laws that may apply in certain circumstances, such as the Endangered Species Act and National Historic Preservation Act, when there are listed species or historic resources at the site.

The discussion that follows describes how EPA's revised interpretation of "begin actual construction" is consistent with (and a better reading of) the relevant regulatory language and explains the Agency's rationale for adopting the revised interpretation.

A. The Revised Interpretation Is Consistent with the Regulatory Text.

As relevant here, the NSR rules define "begin actual construction" in the following terms:

> *Begin actual construction* means, in general, initiation of physical on-site construction activities on an emissions unit which are of a permanent nature. Such activities include, but are not limited to, installation of building supports

[19] *Cf.* 1986 Reich Memorandum at 2.

[20] While the 1978 Reich Memorandum provides some indication of EPA's intent with regard to the 1980 rule, the 1978 memo should not have been cited by both the 1986 Reich Memorandum and the 1993 Howekamp Memorandum as being the basis of, and providing support for, an interpretation of "begin actual construction" that fails to give independent meaning to emissions unit and major stationary source.

> and foundations, laying underground pipework and construction of permanent storage structures.

40 CFR § 52.21(b)(11). The first sentence of this regulatory definition sets forth five distinct criteria that, collectively, identify the type of activity that a source owner or operator is precluded from undertaking prior to obtaining an NSR permit – *i.e.*, activity (1) that is "physical" in nature; (2) that is undertaken "on-site"; (3) that involves "construction";[21] (4) that is "on an emissions unit";[22] *and* (5) that is of a "permanent nature." An activity will constitute the "beginning" of "actual construction" only if it meets all five of these criteria. The fourth criterion is key. A source owner or operator is permitted to undertake a physical on-site construction activity, even if it is of a permanent nature, without having first obtained an NSR preconstruction permit, provided that the activity does *not* involve construction "*on* an emissions unit."

The second sentence of the regulatory definition provides a non-exclusive list of examples of "[s]uch activities." In context, each example must satisfy the criteria in the first sentence of the definition in order for that activity to constitute "begin[ning] actual construction." In particular, the activity must involve construction "on an emissions unit." The regulatory definition would unambiguously allow, therefore, a source owner or operator to undertake the "installation of building supports and foundations" prior to obtaining an NSR permit where the installation in question is not on an emissions unit. On the other hand, in the case of a structure that is itself an emissions unit, the source owner or operator would have to obtain an NSR permit prior to undertaking the "installation of building supports and foundations" where the supports and foundations in question are reasonably considered to be part of the emissions unit.

Similarly, in those cases where a "permanent storage structure" is not an emissions unit (*e.g.*, an equipment storage building), activities associated with its construction can be initiated and proceed to completion prior to issuance of an NSR permit needed for an emissions unit at the same stationary source. Conversely, no construction can be initiated, prior to permit issuance, where the storage structure in question is an emissions unit (*e.g.*, a petroleum or volatile organic liquid tank or vessel).

In placing its focus on those activities that involve "construction . . . on an emissions unit," EPA's revised interpretation of "begin actual construction" gives full effect to the regulatory definition. By contrast, an interpretation that precludes a source owner or operator, prior to obtaining an NSR permit, from undertaking any on-site activity of a "permanent nature," regardless of the relationship between the activity and an emissions unit at the same stationary source for which a permit is needed – *i.e.*, the Agency's prior approach – reads words out of the regulatory text.

B. EPA Has Good Reason to Revise Its Interpretation.

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[21] The term "construction" is defined under the current NSR rules to mean "any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) that would result in a change in emissions." *See* 40 CFR § 52.21(b)(8).

[22] The term "emissions unit" is defined under the current NSR rules to mean "any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant . . . ." 40 CFR § 52.21(b)(7).

While Congress intended the NSR program to function as a preconstruction permitting program – *i.e.*, "No major emitting facility . . . may be constructed . . . unless a permit has been issued for such proposed facility" – as the Agency has long recognized, nothing in the CAA specifies "where on the continuum" from initial "planning" to ultimate "operation" a source owner or operator would run afoul of this statutory provision by acting to "construct" prior to receiving the required permit.[23] The phrase "may be constructed" might reasonably be construed as precluding the initiation of any construction activity prior to the issuance of a permit. On the other hand, the phrase could also reasonably be read to allow construction to proceed right up to the point of near completion, before the source would be considered to have been "constructed." Given this ambiguity, and given that Congress provided neither a statutory definition of "constructed" nor a meaningful definition of "construction,"[24] EPA has discretion to determine where on that "continuum" it should draw a reasonable line. In 1980, EPA through rulemaking chose to draw that line at the point where "physical on-site construction activities" take place "on an emissions unit." While EPA would be authorized to change that regulatory definition through a further rulemaking, at this time, the Agency is acting merely to provide a revised interpretation of that definition that is consistent with the regulatory text.

EPA has two reasons for providing a revised interpretation at this time. First, EPA has determined that its prior interpretation failed to give meaning to the distinction between emissions unit and major stationary source in the regulatory text. Second, EPA is less concerned now with the risks that formed the longstanding rationale for its prior approach.

The revised interpretation set forth in this memorandum is expected to have no emissions consequences. Nor will it result in any adverse effect on the environment. It remains the case under this revised interpretation that only after receiving the required NSR permit may a source owner or operator initiate permanent construction on, and subsequent operation of, an emissions unit. As has always been the case, any on-site construction or preparatory activity that a permit applicant undertakes prior to receiving a required NSR permit will be at the applicant's own risk.

1. EPA's Revised Interpretation Is A Better Reading of the Regulatory Text.

Even after EPA had incorporated into its NSR rules in 1980 the term "begin actual construction," the Agency, in interpreting and applying that new regulatory term, continued to follow the policy set forth in the December 1978 Reich Memorandum. However, the 1978 PSD rules (i) did not contain the term "begin actual construction;" (ii) did not employ the term "emissions unit;" and (iii) did not "explicitly answer the question" of "where on the continuum from planning to operation of major emitting facility does a company or other entity violate the PSD regulations if it has not yet received a PSD permit."[25] As a consequence of not giving

[23] December 1978 Reich Memorandum at 1.

[24] *See* note 8, above.

[25] December 1978 Reich Memorandum at 1.

sufficient attention to these details, EPA adopted an interpretation of "begin actual construction" in 1986 that failed to give meaning to different parts of the regulatory text that was enacted in 1980 and that, as applied to specific situations, has resulted in the Agency's determining that activities that clearly do not involve construction "on an emissions unit" nevertheless constitute the "begin[ning of] actual construction."

As was previously noted, EPA first provided an interpretation of the term "begin actual construction" in the 1986 Reich Memorandum. EPA acknowledged at that time that the regulatory definition focuses specifically, and exclusively, on activities that involve construction "on an emissions unit." *See* 1986 Reich Memorandum at 1 ("[T]he term 'begin actual construction' at Section 52.21(b)(11) . . . refers to 'construction activities on an emission unit.'"). Further, EPA recognized that, under this definition, it would now be necessary to draw a distinction between a "major stationary source" on the one hand and an "emissions unit" on the other, insofar as an emissions unit is, by definition, a *part* of a stationary source. *Id.* at 2 ("[A]lthough applicability of PSD is determined on a source-wide basis, it may become necessary to distinguish the emissions unit from the major stationary source or modification in order to determine at what point in construction planning or construction activities a PSD permit is required.").[26]

Despite creating and acknowledging this distinction between a "major stationary source" on the one hand and an "emissions unit" on the other, EPA's 1986 Reich Memorandum adopted an overly broad reading of the term "emission unit." EPA took the position that it was "necessary to clarify the definition of emissions unit" and deemed an emissions unit to "include any installations necessary to accommodate that unit." *Id.* "Therefore," EPA stated, "before issuance of the PSD permit, construction is prohibited on any emissions unit or on any installation designed to accommodate the emissions unit." *Id.* This interpretation failed to adequately reflect the distinction EPA had simultaneously identified between a major stationary source and an emissions unit.

In the 1980 NSR rules, "emissions unit" had been defined to mean "any part of a stationary source which emits or would have the potential to emit any pollutant subject to regulation under the Act." The phrase "which emits or would have the potential to emit" is best understood to modify the term "part." A "part" of a stationary source that does not "emit" or "have the potential to emit" is not an emissions unit. But without pointing to any particular language in this definition, in the 1986 Reich Memorandum, EPA construed the term "emissions unit" to include "any installations necessary to accommodate that unit." EPA does not today believe such an interpretation to be appropriate because it has no support in the text of the regulation and has been applied to reach "parts" of a stationary source that do not emit.[27] Although EPA acknowledged

[26] As the pertinent regulatory language provided in 1980, and as it provides today, an "emissions unit" is defined to mean "any *part of* a stationary source which emits or would have the potential to emit any pollutant . . . ." 40 CFR § 52.21(b)(7) (emphasis added).

[27] It is also not appropriate to read the language of the 1980 NSR rules' definitions of either "emissions unit" or "begin actual construction" to support the follow-on statement in the 1986 Reich Memorandum that, where "the emissions unit (including any accommodating installation)" is an "integral part of the source or modification (i.e. the source or modification would not serve in accordance with its original intent, except for inclusion of the emissions unit)," an NSR permit "must be obtained before construction on the entire source commences." 1986 Reich Memorandum at 2-3.

that, given the 1980 NSR rules' definition of "begin actual construction," it would be necessary for the Agency to "distinguish the emissions unit from the major stationary source or modification," EPA's clarification" of the term "emissions unit" for all practical purposes erased the distinction between "emissions unit" and "stationary source." EPA has effectively construed the phrase "that emits or would have the potential to emit" to modify the term "stationary source" rather than the word "part." The noun in this part of the sentence, however, is best understood to be a "part of a stationary source." The term "stationary source" is separately defined in the PSD regulations as "any building, structure, facility, or installation which emits or may emit a regulated NSR pollutant." 40 CFR 52.21(b)(5). Thus, within the definition of "emissions unit," the phase "emits or would have the potential to emit" is not needed to give meaning to the term "stationary source." Accordingly, the most sensible reading is that an emissions unit is the "part" of a stationary source "that emits."

The interpretation of "emissions unit" reflected in the 1986 Reich Memorandum underpinned EPA's approach in subsequent guidance and applicability determinations. For example, in the 1993 Rasnic Memorandum, EPA relied upon the approach and rationale of the 1986 Reich Memorandum in stating that "all on-site activities of a permanent nature aimed at completing a PSD source for which a permit has yet to be obtained are prohibited under all circumstances," and that "such prohibited activities . . . include any emissions unit *or installation necessary to accommodate the PSD source*." 1993 Rasnic Memorandum at 1 (emphasis added). This emphasized phrase is not found in the definition of "emissions unit" and is unnecessary because it immediately follows the defined term. Furthermore, the 1993 Rasnic Memorandum continued to use the term "PSD source" rather than the term "emissions unit" that appears in the regulatory text.

Elsewhere in the 1993 Rasnic Memorandum, EPA characterized the regulatory definition of "begin actual construction" as "prohibit[ing] any construction activities that are of a permanent nature related to the specific project for which a PSD permit is needed, as opposed to general construction activities not related to the emissions unit(s) in question, prior to the receipt of a construction permit." 1993 Rasnic Memorandum at 2. Although EPA recognized the distinction between construction activities that involve an emissions unit and those that do not, the Agency disregarded that distinction, stating that "[t]his standard prohibits activities *affecting the property in a permanent way* that the source would reasonably undertake *only with the intended purpose of constructing the regulated project*." *Id.* (emphases added). This is not the best reading of the regulatory text.[28]

Based on this interpretation, EPA found in the 1993 Rasnic Memorandum that the construction of a retaining wall to shore up an excavated pit at the site of an oriented strand board plant proposed to be built by Georgia-Pacific could not begin in advance of the issuance of a PSD permit. "Our policy," EPA explained, "focuses on the relation of the activity to the PSD source," while distinguishing between "activities of a preparatory nature from those of a permanent nature." 1993 Rasnic Memorandum at 2. "Construction of a retaining wall," EPA continued, "is considered

[28] The 1993 Rasnic Memorandum represents that the "regulations and several memoranda specifically state that 'begin actual construction means initiation of physical on-site construction activities . . . which are of a permanent nature.'" *See* 1993 Rasnic Memorandum at 1. The omitted text represented by the ellipsis is comprised of the words "on an emissions unit."

an activity under 'begin actual construction' because it is of a permanent nature." *Id.* Even the "excavation activities" were found by EPA to fit "within the meaning of 'begin actual construction,'" since they were "costly, they significantly alter[ed] the site, are an integral part of the overall construction project, and are clearly of a permanent nature." *Id.* at 3.

The conclusion that such activities could not be permissibly undertaken prior to the issues of a PSD permit exemplifies how the approach to "begin actual construction" taken by the 1986 Reich Memorandum fails to give independent meaning to the term "emissions unit." Neither the excavation of ground nor the subsequent construction of a retaining wall within the excavated space could fairly be considered construction "on an emissions unit" by themselves. EPA focused here on the permanent nature of the activities without paying sufficient attention to whether these activities were "on an emissions unit." EPA appears to have precluded the activities not due to any demonstration that these activities were, in fact, part of an emissions unit, or that they would result in an emissions increase, but because EPA determined the activities to be permanent when considered in the context of the major stationary source subject to a permit.

Similarly, in the 1995 Seitz Letter, EPA had stated that, under 40 CFR §§ 52.21(i)(1) and (b)(11) . . . "*any* permanent and/or preparatory" construction activity that is "costly, significantly alters the site, and/or permanent in nature" is "prohibited" prior to the source's obtaining an NSR permit. 1995 Seitz Letter at 2 (emphasis added). EPA continued that "[t]his would include, but is not limited to: (1) excavating, blasting, removing rock and soil, and backfilling, and (2) installing footings, foundations, permanent storage structures, pipe, and retaining walls." *Id.* In support, EPA pointed to what it described as its "longstanding policy that section 52.21(i) reasonably prohibits any preconstruction 'intended to accommodate' an 'emissions unit' or which is an 'integral part of the source or modification.'" 1995 Seitz Letter at 2. That "longstanding policy," EPA stated, had first been announced in the 1986 Reich Memorandum. *Id.* However, by this time, EPA had so thoroughly erased the distinction between a major stationary source and an emissions unit that it did not explain how site clearing and grading, which were allowed under the 1978 policy, could not include excavating, blasting, removing rock and soil, and backfill.[29]

The position taken in the 1995 Seitz Letter that "any" permanent or preparatory activity (even site clearing, grading, and installation of retaining walls) is prohibited where that activity is "costly," "significantly alters the site," or is "permanent in nature" is inconsistent with the 1978 policy EPA codified in the 1980 regulation and fails to give meaning to the relevant regulatory language adopted in 1980. Such a reading does not make the necessary distinction between an activity that involves an emissions unit and an activity that does not. This is another example of how the interpretation of "emissions unit" set forth in the 1986 Reich Memorandum, when applied

[29] The 2014 Amendments to the Federal Indian Country—Amendments to the Federal Indian Country Minor New Source Review Rule promulgated a definition for "begin construction" that was identical to that promulgated in the 1980 NSR rules but also enumerated certain preparatory activities that would be excluded including "[e]ngineering and design planning, geotechnical investigation (surface and subsurface explorations), clearing, grading, surveying, ordering of equipment and materials, storing of equipment or setting up temporary trailers to house construction management or staff and contractor personnel." 40 CFR § 49.152. This provides further evidence that EPA did not conceive activities not on an emissions unit (i.e., clearing, grading, surveying) to be considered "begin actual construction."

to actual site-specific circumstances, can produce a result that is contrary to what a straightforward application of the relevant regulatory language would provide.

In this regard, some of the on-site activities that the 1993 Rasnic Memorandum and the 1995 Seitz Letter identify as being precluded prior to issuance of an NSR permit – *i.e.*, "blasting," "excavation," "backfilling,"– do not appear to meet the regulatory definition of the term "construction" itself.[30] This is a peculiar result that underscores how application of the 1986 Reich Memorandum became increasingly disconnected from the plain language of the relevant regulatory text.

2. The Rationale for EPA's Prior Interpretation Was Based on Considerations of Less Concern Today.

The only rationale that EPA has provided for its policy of requiring sources to obtain an NSR permit prior to undertaking any on-site construction activity "of a permanent nature" was first articulated in the October 1978 Reich Memorandum. There, EPA expressed concern that it would be "extremely difficult to deny issuance of a permit when it results in a completed portion of a project having to remain idle." October 1978 Reich Memorandum at 2. "Therefore," EPA reasoned, "in order to avoid any equity arguments at a later time, it is better to prevent any construction now rather than have a 'white elephant' on our hands later on." *Id.* The Agency has since reiterated this position in subsequent guidance and a proposed rulemaking.[31]

Underpinning these concerns about a source owner or operator being allowed to place "equity in the ground" by engaging in costly and permanent on-site construction activities prior to receiving an NSR permit is the presumption that, in doing so, the owner or operator would gain "leverage" in the permitting process. That is to say, in such circumstances, it is supposed the permitting authority might feel compelled to issue a permit that was not as stringent in its terms as it otherwise would have been.

However, EPA no longer believes that this original rationale provides a good basis for interpreting the term "begin actual construction" to preclude *any* activity "of a permanent nature" regardless of whether that activity involves construction "on an emissions unit." While EPA's

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[30] The NSR rules' definition of "construction" itself focuses on activities that involve an "emissions unit." Activities such as blasting, excavation, backfilling, and building a retaining wall do not constitute the "fabrication, erection, installation, demolition, or modification" of an emissions unit, nor is any of them a "physical change or change in the method of operation . . . that would result in a change in emissions" within the plain terms and evident meaning of 40 CFR § 52.21(b)(8).

[31] *See, e.g.*, 1993 Rasnic Memorandum at 2 (A "permitting authority would be placed in a very difficult position when denying issuance of a permit when it results in a completed portion of a project having to remain idle."); 1995 Seitz Letter at 2 ("[A]bsent a prohibition on any costly, significant or permanent preconstruction," sources could "defeat" the "preconstruction requirement or its enforcement by making a costly, substantial, and/or permanent investment" and then "later argue that retrofitting of PSD requirements or a denial of the permit would unreasonably interfere with their investment."); 61 FR 38270 ("If . . . companies were given unlimited ability to place 'equity in the ground' by constructing plants before a permit is issued," then a permitting authority's "discretion in making permit decisions may be compromised" and the "ability of EPA and citizens to challenge the permit that is eventually issued may likewise be undermined.").

concerns over potential "equity" arguments may have had validity at the inception of the NSR preconstruction permitting program in 1978, when both EPA and state permitting authorities as yet lacked experience in implementing the program, the Agency does not believe that such concerns are warranted today. Today, EPA finds it implausible that state and local permitting authorities, with some 40 years of experience in implementing the NSR preconstruction permitting program, would allow their judgment to be compromised in making permitting decisions by any "equity in the ground"-type arguments that could potentially be advanced by permit applicants who may have previously expended time, money, and other resources in undertaking on-site construction activities of a significant nature (*e.g.*, costly, permanent). For example, a PSD permitting authority must still continue to determine BACT for a new emissions unit at a facility based upon the permit application submitted, without regard to the preparatory activities an applicant may conduct on the site.[32]

Nor does EPA find it plausible that NSR permit applicants themselves imagine that undertaking significant on-site construction activities prior to permit issuance will allow them to gain leverage with respect to the outcome of the permitting process. Stationary source owners or operators cannot expect that any site activities prior to permitting will alter or influence the BACT analysis for an emissions unit or other elements of a permitting decision. Permit applicants that choose to undertake on-site construction activities in advance of permit issuance do so at their own risk. Given this, it is reasonable to imagine scenarios under which the greater the irretrievable commitments a permit applicant may make to construct a particular source at a particular site – *i.e.*, the *more* "equity" the prospective source owner or operator were to place "in the ground" – the *less* leverage, as a practical matter, that applicant would retain in the permitting process. With the prospective owner or operator having made such significant commitments, it is conceivable that, during negotiations over the terms and conditions that were to be included in the permit, the prospective owner or operator would be more motivated to accept proposals made by the permitting authority or by interested outside parties, where doing so would bring to a conclusion an otherwise lengthy and contentious permitting process that threatened to delay construction and the time at which the prospective owner or operator would begin to realize a return on investment.

In sum, EPA no longer believes that its previous concerns over potential "equity" arguments provide sufficient justification for retaining such a restrictive policy on "begin actual construction," particularly given that, as has been explained, that policy was predicated on an interpretation that reads the term "emissions unit" so expansively that it erases the distinction between the regulatory definition of an emissions unit and a stationary source. Further, because EPA has now determined that prior policy is no longer necessary to prevent some potential compromise of the NSR permitting process, there is no reason to believe that the adoption of the revised interpretation set forth here will result in, or could result in, any adverse effects on the environment. The outcome of a permitting decision should not be any different because a source undertakes construction activity on those parts of a facility that are not emissions units prior to obtaining a PSD permit for the construction of, or modification to, an emissions unit.

IV. Determining the Scope of an Emissions Unit

[32] Accordingly, the permitting authority, in conducting an analysis of BACT should not include the cost of any adjustments or modifications to already constructed portions of the facility necessary to install any particular control technology when determining the cost of that technology.

While EPA has sought to clarify in this memo that some activities should no longer be considered construction on an emissions unit that is prohibited without a permit, EPA recognizes that both sources and permitting authorities, in order to ascertain whether particular on-site activities involves "construction . . . on an emissions unit" within the meaning of 40 CFR § 52.21(b)(11), will still have to make case-specific determinations regarding the scope of the emissions unit in question.[33] In so doing, these parties will have to exercise judgment to resolve a matter presenting potentially complicated technical questions.

Providing detailed guidance on how the specific parameters of an emissions unit are to be ascertained for purposes of determining whether a given activity constitutes "construction . . . on an emissions unit" is beyond the scope of this memorandum. EPA notes, however, that this is a task that sources and permitting authorities are already called upon to do, and with which they have experience, albeit in different contexts. It is also an area where EPA has previously provided direction on a case-specific basis.

For example, when EPA was asked "how the 'emissions unit' should be defined" for purposes of applying BACT at a synthetic fiber manufacturing facility, the Agency observed that a New Source Performance Standard (NSPS) is "one source of information that may be helpful in defining an emission unit for the purpose of evaluating control options" in PSD permitting. *See* Letter from Judith M. Katz, Director, Air Protection Division, EPA Region III to John M. Daniel, Jr., Director, Air Program Coordination, Virginia Department of Environmental Quality (November 30, 2000) at 3. Specifically, EPA was asked whether the separate pieces of equipment comprising a solvent-spun synthetic fiber process located at the manufacturing site should each be considered separate emissions units or whether the entire process should be considered a single emissions unit. In response, the Agency pointed to the relevant NSPS, Subpart HHH, Standards of Performance for Synthetic Fiber Production Facilities, which provided that the entire solvent-spun synthetic fiber process was the "affected facility," and that this affected facility "includes spinning solution preparation, spinning, fiber processing (wash/draw) and solvent recovery, but does not include the polymer production equipment." *Id.* at 3.

EPA noted that its guidance in this instance was "consistent with guidance issued by EPA, Region VIII in a letter dated February 6, 1990, regarding a determination of Lowest Achievable Emission Rate . . . for Coors Container." *Id.* at 3. In that case, EPA had "determined that an emissions unit consisted of the entire coating operation . . . based on the NSPS definition of affected facility for that source category (Subpart WW)." *Id.* "The NSPS definition," EPA continued, "was relied on because the rule provided a rationale as to why these processes should be grouped together for purposes of setting a unique emission limitation covering all the equipment." *Id.* at 3-4.

[33] The December 1978 Reich Memorandum had identified as one of "advantages" presented by the then-"new policy" that it would be "easy to administer, since case-by-case determinations will not be required." December 1978 Reich Memorandum at 2. As explained above, EPA adopted, at that time, an approach under which essentially any on-site activity of a "permanent" nature was precluded unless, and until, the source had obtained an NSR permit. While ease of administration and a desire to avoid case-specific determinations are themselves laudable goals, the Agency must also interpret and apply its rules in a manner that it consistent with the plain text of those rules.

More recently, EPA addressed this issue of determining the scope of an emissions unit in connection with the permitting of semiconductor manufacturing facilities under the PSD program. When EPA was asked whether certain state and local permitting authorities had acted properly in treating an individual semiconductor fabrication building (a "fab") as a single emissions unit for purposes of determining PSD applicability, the Agency responded that this "approach seems appropriate because of the interconnected nature of the 'tools' in the fab," and given that the "systems that deliver materials to those tools and manage their discharges have also generally been treated as part of the emissions unit." *See* Letter from Stephen D. Page, Director, Office of Air Quality Planning and Standards to David Isaacs, Vice President, Government Policy, Semiconductor Industry Association (August 26, 2011). In support, EPA added that, "although not determinative, New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) can be sources of information that may be helpful in defining an emission unit." *Id.* at 2-3. In this particular case, EPA found that NESHAP Subpart BBBBB, National Standards for Hazardous Air Pollutants for Semiconductor Manufacturing "provides relevant information on what a semiconductor manufacturing process unit," and, in turn, what an "emissions unit" for purposes of NSR "might be." *Id.* at 3.

However, not all determinations of emissions unit for NSR permitting rely on a precedent or framework established by an NSPS or NESHAP. In a recent letter, EPA defined "emissions unit" in the context of a marine oil loading terminal, determining that the addition of a new emissions point that would load crude oil offshore is part of a single emissions unit with the source's existing onshore loading and unloading operation consisting of ten docks. *See* Letter from William L. Wehrum, Assistant Administrator, EPA Office of Air and Radiation, to LeAnn Johnson Koch, Perkins Coie, Re: Limetree Bay Terminals, St. Croix, U.S. Virgin Islands – Permitting Questions (April 5, 2018). The Limetree Bay Terminals (LBT) project, referred to as a single point mooring (SPM), "would 'extend from the jetty on the seabed for approximately 5,800 feet to a Pipeline End Manifold' that would be connected to a buoy via a flexible hose, and the buoy would load/unload crude oil onto ships via two floating hoses." *Id.* at 6. In its determination that the proposed SPM and the existing loading terminal are considered a single emissions unit, EPA reasoned that the SPM "would not change the nature of the pollutant-emitting activity occuring at the existing marine terminal" and that it would be "physically connected to the existing marine loading terminal by way of an underwater piping system and will be completely integrated with the loading and storage operations at the existing terminal. Consequently, the SPM and current marine terminal appear to share the same interconnectedness that EPA previously found persuasive in its analysis of semiconductor fabs, which supports treating LBT's proposed SPM and the existing terminal as a single emissions unit." *Id.* at 7. Thus, in this instance, EPA did not specifically rely on an applicable NSPS or NESHAP to guide its decision, and it instead focused its case-specific analysis on other considerations, including one of the factors it previously used in defining the emissions unit for the semiconductor manufacturing facilities, in arriving at its decision.

EPA expects that sources will continue to work with their permitting authorities to determine the scope of an "emissions unit" for the purpose of evaluating whether a particular activity constitutes "construction . . . on an emissions unit" within the meaning of 40 CFR § 52.21(b)(11). As illustrated above, the definition of "affected facility" and/or "process unit" under a relevant NSPS or NESHAP can occasionally provide useful direction for this analysis.

Nevertheless, in making this determination, a source or permitting authority would be acting contrary to the purpose and intent of EPA's interpretation of "begin actual construction" set forth here were that source or permitting authority to take an unduly broad or otherwise unreasonable view of the scope of an emissions unit that fails to recognize a distinction between an emissions unit and the major stationary source.

* * * *

The guidance contained herein is an interpretation or "interpretive rule" not subject to notice-and-comment rulemaking requirements, and this memorandum does not itself create or alter any binding requirements on regulatory agencies, permit applicants, or the public. This revised interpretation is intended to be implemented by EPA Regional offices and by those air agencies to which EPA has delegated its authority to issue federal PSD permits under 40 CFR § 52.21(u). EPA is also making this memorandum available as guidance for consideration by air agencies with SIP-approved programs. Depending on the particular regulatory context and wording of the applicable SIP, air agencies implementing a SIP-approved program may be able to apply this revised interpretation as well.

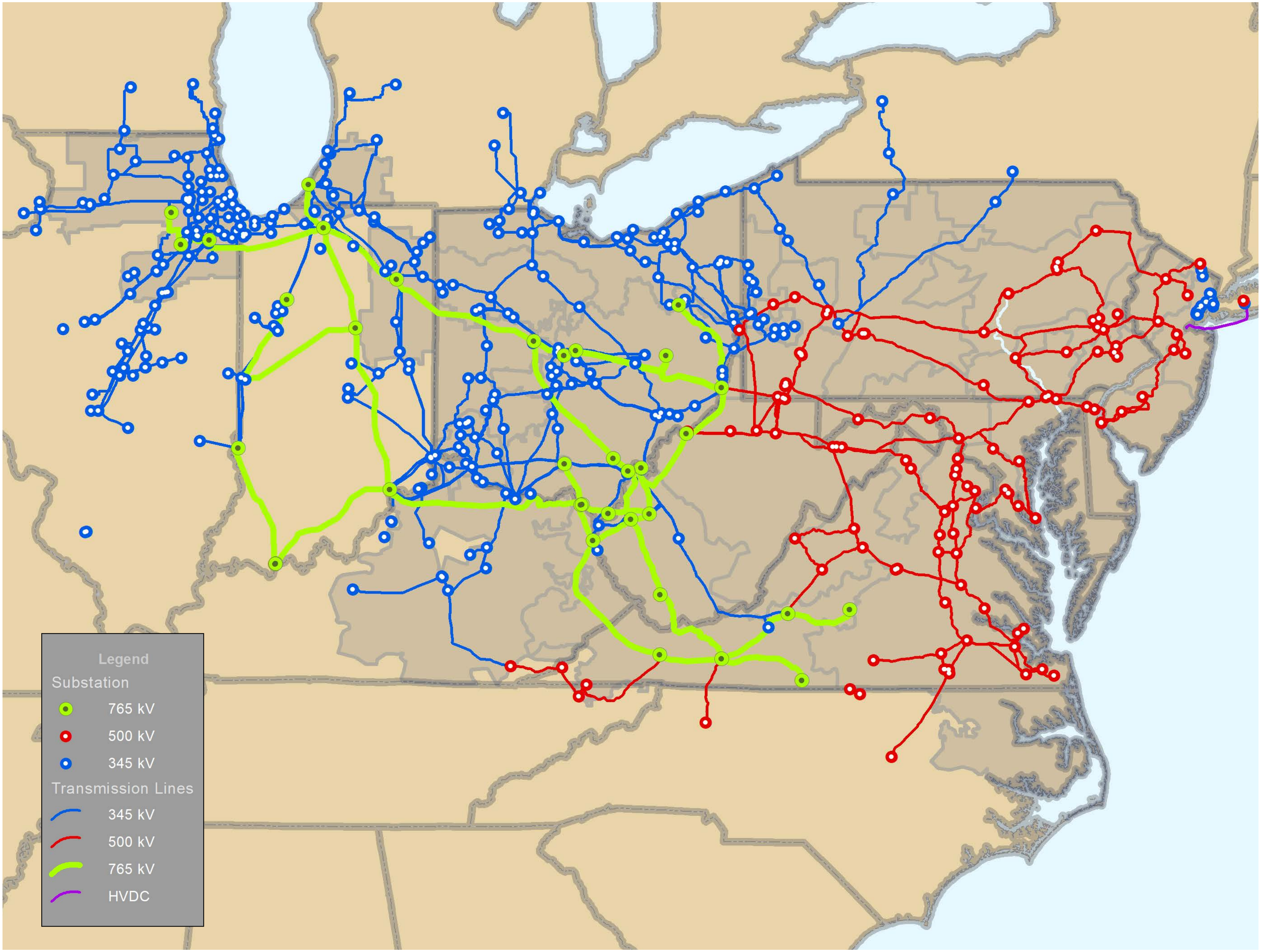
For any questions concerning this memorandum, please contact Juan Santiago, Associate Division Director of the Air Quality Policy Division, Office of Air Quality Planning and Standards at (919) 541-1084 or *santiago.juan@epa.gov*.

RTEP

2020 REGIONAL TRANSMISSION EXPANSION PLAN

FEBRUARY 28, 2021

pjm®


Legend
Substation
765 kV
500 kV
345 kV
Transmission Lines
345 kV
500 kV
765 kV
HVDC

Preface

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

1.0: Preface

The PJM Regional Transmission Expansion Plan (RTEP) Report is published annually to convey planning study results throughout the year, and to explain the rationale behind transmission system enhancement need.

In 2020, PJM observed several ongoing trends, which are discussed throughout this report. These include the continuing shift in PJM's generation fuel mix, driven by new natural-gas-fired plants and deactivation of coal-fired plants.

- **Section 1** is a high-level summary of 2020 RTEP activities, including process improvements and a summary of projects organized by driver.
- **Section 2** includes an overview and detailed data from PJM's 2020 Load Forecast Report.
- **Section 3** provides 2020 RTEP project highlights, generator deactivations and re-evaluation of previously approved projects.
- **Section 4** summarizes the market efficiency process, including input assumptions, analysis and competitive windows.
- **Section 5** provides an overview of PJM's new service queue requests.
- **Section 6** includes state summaries, including a detailed breakdown of interconnection requests within each individual state in PJM, as well as transmission system enhancements identified as part of the RTEP analysis.
- **Appendix 1** – Tranmission Owner Zones and Locational Deliverability Areas
- Glossary
- Topical Index
- Key Maps, Tables and Figures
- RTEP Project Statistics

Planning Community

PJM's online communities create an easily accessible venue for stakeholders to collaborate with PJM staff and each other.

The Planning Community allows stakeholders to collaborate and find information on planning initiatives, proposal windows and processes. It includes similar features to the Member Community, along with:

- Access to PJM subject matter experts
- Moderated discussions between generation owners, transmission owners and PJM staff

Request access at
https://pjm.force.com/planning/s/

RTEP Process Description

The online resources below provide additional description of RTEP process business rules and methodologies:

- The Manual 14 series contains the specific business rules that govern the RTEP process. Specifically, Manual 14B describes the methodologies for conducting studies and developing solutions to solve planning criteria violations and market efficiency issues. PJM Manual 14B, Regional Planning Process, is available on the PJM website.

- Schedule 6 of the PJM Operating Agreement codifies the overall provisions under which PJM implements its Regional Transmission Expansion Planning protocol, more familiarly known (and used throughout this document) as the PJM RTEP process. The PJM Operating Agreement is available on the PJM website.

- The PJM Open Access Transmission Tariff (OATT) codifies provisions for generating resource interconnection, merchant/customer-funded transmission interconnection, long-term firm transmission service and other specific new service requests. The PJM OATT is available on the PJM website.

- The status of individual PJM Board-approved baseline and network RTEP projects, as well as that of Transmission Owner Supplemental Projects, is available on the PJM website.

Stakeholder Forums

The Planning Committee, established under the PJM Operating Agreement, has the responsibility to review and recommend system planning strategies and policies, as well as planning and engineering designs for the PJM bulk power supply system to assure the continued ability of the member companies to operate reliably and economically in a competitive market environment.

Additionally, the Planning Committee makes recommendations regarding generating capacity reserve requirements and demand-side valuation factors. Committee meeting materials and other resources are available on the PJM website.

The Transmission Expansion Advisory Committee (TEAC) and Subregional RTEP committees continue to provide forums for PJM staff and stakeholders to exchange ideas, discuss study input assumptions and review results. Stakeholders are encouraged to participate in these ongoing committee activities. TEAC resources are available on the PJM website.

Each Subregional RTEP committee provides a forum for stakeholders to discuss local planning concerns. Interested stakeholders can access Subregional RTEP committee planning process information from the PJM website:

- PJM Mid-Atlantic Subregional RTEP
- PJM Western Subregional RTEP Committee
- PJM Southern Subregional RTEP Committee

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Section 1: 2020 Executive Summary

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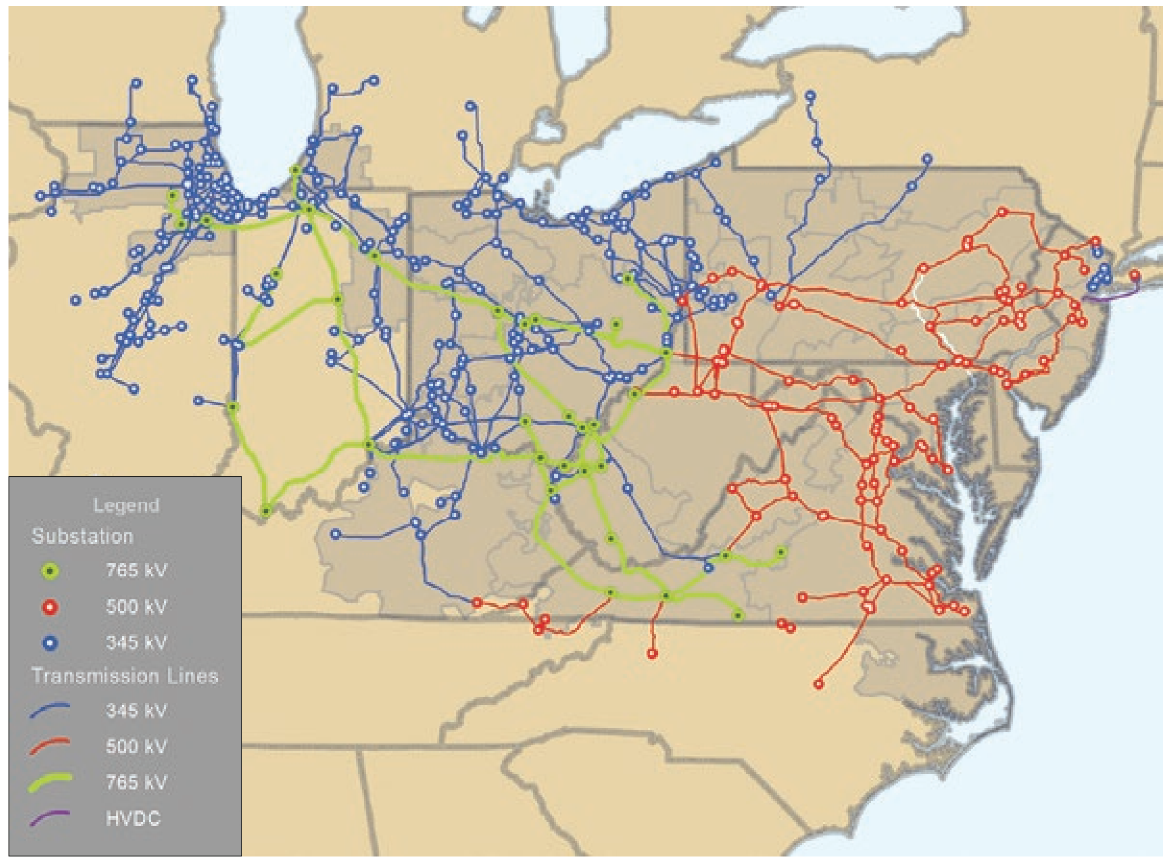
1.0: 2020 Executive Summary

1.0.1 — Regional Planning

PJM, a FERC-approved RTO, coordinates the movement of wholesale electricity across a high-voltage transmission system in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia, as shown on **Map 1.1**. PJM's footprint encompasses major U.S. load centers from the Atlantic Coast to the Illinois western border, including the metropolitan areas in and around Baltimore, Chicago, Columbus, Cleveland, Dayton, Newark and Northern New Jersey, Norfolk, Philadelphia, Pittsburgh, Richmond, Toledo and the District of Columbia.

PJM's Regional Transmission Expansion Plan (RTEP) process identifies transmission system additions and improvements needed to serve more than 65 million people throughout 13 states and the District of Columbia. The PJM system includes key U.S. Eastern Interconnection transmission arteries, providing members with access to PJM's regional power markets as well as those of adjoining systems. Collaborating with more than 1,000 members, PJM dispatches more than 185,000 MW of generation capacity over 85,000 miles of transmission lines.

Map 1.1: PJM Backbone Transmission System



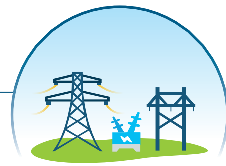
KEY 2020 HIGHLIGHTS

Forty-three new baseline projects were planned during 2020 at an estimated cost of $413 million to ensure fundamental system reliability across the grid. Fifty-five new network transmission projects at an estimated cost of $101 million are required to ensure the reliable delivery of generation seeking interconnection to PJM markets.

Renewables in PJM's interconnection queue now exceed other fuels with 88 percent wind, solar and storage. Overall, nearly 2,000 MW of units across all fuel types reached commercial operation across the PJM region in 2020, including a pilot offshore wind project in Virginia.

PJM and MISO Boards approved the first interregional market efficiency transmission project – replacement of the Michigan City-Trail Creek-Bosserman 138 kV line – based on a competitive planning process.

- Over 1.96 GW of new generation reached commercial operation.
- Wind, solar and storage requests now total over 120,000 MW in PJM's interconnection queue. Solar has more than doubled over 2019, now comprising 56 percent of PJM's queue.
- PJM processed 1,028 requests to interconnect new generation totaling 70,375 MW, nameplate capability, and 44,179 MW of capacity interconnection rights (CIRs) for which 1,424 feasibility, system impact and facilities studies were issued to developers.



- Baseline projects in 2020 driven by TO criteria violations comprised 64 percent ($264 million) of approved baseline projects. 22 percent were driven by generator deactivations. 14 percent were driven by NERC, TO and PJM baseline criteria.
- Twenty-two deactivation notifications totaling 4,428 MW were received during 2020. Twenty-nine units totaling 3,300 MW formally retired in 2020.
- PJM and New Jersey announced the implementation of the RTEP Process State Agreement Approach to develop public policy-driven transmission to satisfy state offshore wind power objectives.

- PJM 2020 forecasted load growth rate remained flat at a 10-year RTO summer, normalized peak growth rate of 0.6 percent.
- Load forecasting improvements continued in 2020, focusing on reducing summer and winter forecast error with refinements to both sector and non-weather-sensitive model components.
- PJM's Installed Reserve Margin for the 2021/2022 Delivery Year declined from 15.1 percent to 14.7 percent, driven by a strong generation performance and a subsequent reduction in generation forced outage rates, particularly for. natural gas-powered combined cycle units.
- The COVID-19 pandemic had an immediate and significant impact on PJM load beginning in mid-March 2020 – reducing energy demand by greater than 10 percent at its most severe level in the spring – and subsiding during the summer. Total COVID-19-related impact on PJM energy in 2020 was estimated to be about negative 5 percent.

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RTO Perspective

PJM's RTEP process spans state boundaries shown in **Map 1.1** and is a key RTO function, as shown in **Figure 1.1**. A regional perspective gives PJM the ability to identify one optimal, comprehensive set of solutions to solve reliability criteria violations, operational performance issues and market efficiency constraints. Specific system enhancements are justified to meet local reliability requirements and deliver needed power to load centers across PJM. When the PJM Board of Managers approves recommended system enhancements, new facilities and upgrades to existing ones, they formally become part of PJM's RTEP. PJM recommendations can also include the removal of, or change in scope to, previously approved projects. Expected system conditions can change such that justification for a project no longer exists nor requires modification to capture scope changes.

System Enhancement Drivers

A 15-year, long-term planning horizon allows PJM to consider the aggregate effects of many drivers, shown in **Figure 1.2**. Initially, with its inception in 1997, PJM's RTEP consisted of system enhancements mainly driven by load growth and generating resource interconnection requests. Today, PJM's RTEP process studies the interaction of many drivers, including those arising out of reliability, aging infrastructure, operational performance, market efficiency, public policy and demand-side trends. Importantly though, as **Figure 1.2** shows, RTEP development considers all drivers through a reliability criteria and resilience lens. PJM's RTEP process encompasses a comprehensive assessment of system compliance

Figure 1.1: RTEP Process – RTO Perspective

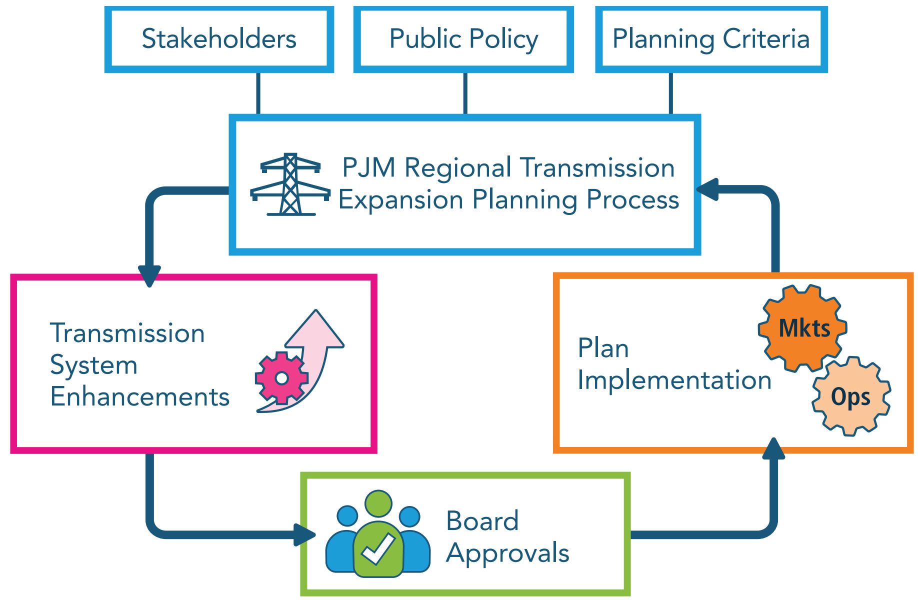
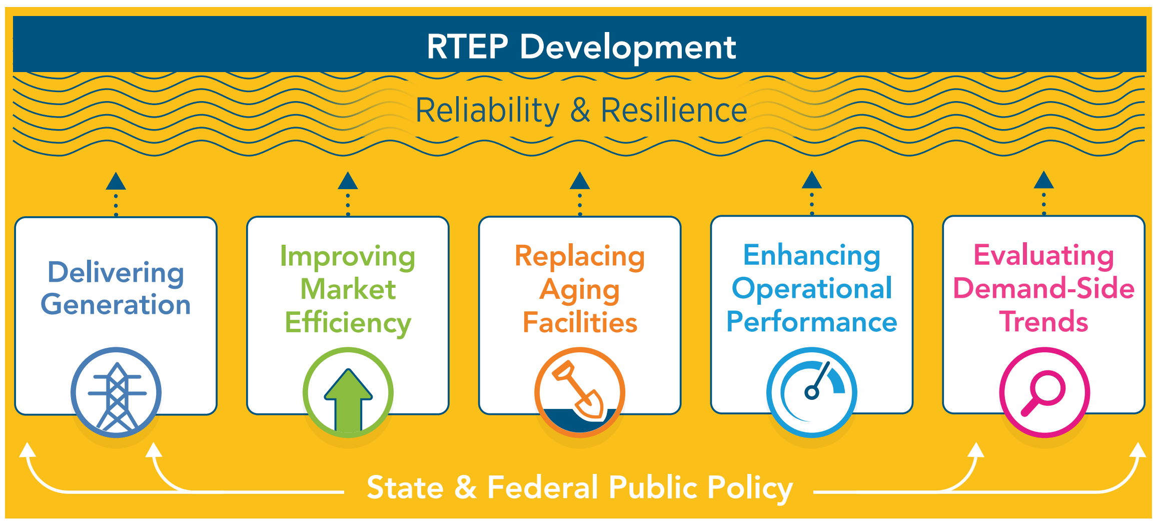


Figure 1.2: System Enhancement Drivers



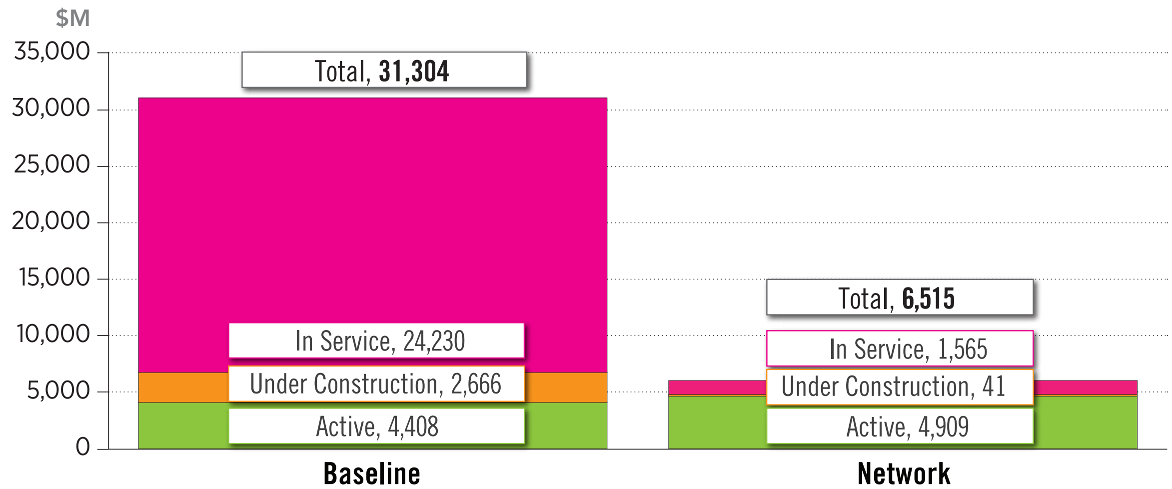
with the thermal, reactive, stability and short-circuit North American Electric Reliability Corp. (NERC) Standard TPL-001-4 as described in **Section 1.2**.

Highlights of projects identified and approved by the PJM Board during 2020 appear in **Section 3**. Details of specific large-scale projects – those greater than or equal to $10 million in scope – are presented in **Section 6**.

1.0.2 — 2020 Outcomes and Conclusions

At its most fundamental, the PJM transmission system ensures that electricity can be delivered reliably across the grid to customers the instant it is needed. PJM's 2020 RTEP process continued to yield grid enhancements to ensure that delivery under a historic and unprecedented generation shift is now driven increasingly by public policy and fuel economics.

Figure 1.3: Board-Approved RTEP Projects as of Dec. 31, 2020



- The PJM Board approved 43 new baseline projects during 2020 at an estimated $413 million to ensure that fundamental system reliability criteria across the grid are met. Projects driven by TO criteria violations comprised 64 percent ($264 million) of approved baseline projects. 22 percent were driven by generator deactivations. 14 percent were driven by other NERC and PJM reliability criteria.
- Notably, baseline projects in 2020 also included PJM's first interregional market efficiency transmission project – replacement of the Michigan City-Trail Creek-Bosserman 138 kV – approved by PJM and MISO Boards and was the outcome of an interregional competitive planning process to reduce congestion along the PJM/MISO seam.
- The Board also approved 55 new network transmission projects at an estimated $101 million.

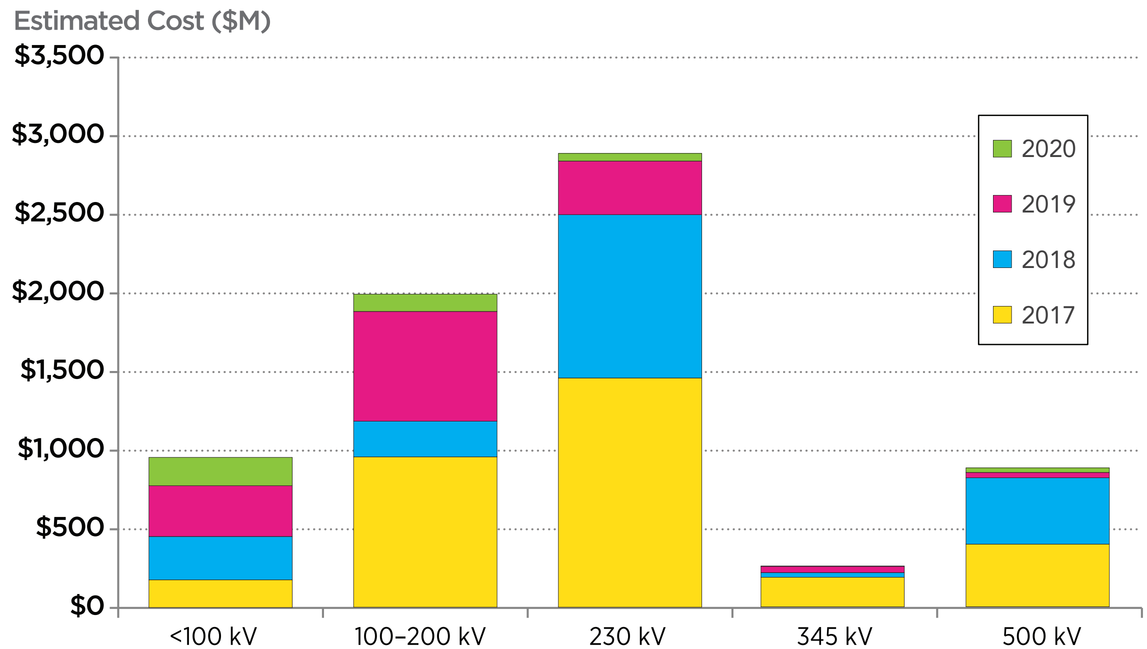
The PJM Board has approved transmission system enhancements totaling approximately $37.8 billion. Of this, approximately $31.3 billion represents baseline projects to ensure compliance with NERC, regional and local transmission owner planning criteria and to address market efficiency congestion relief. An additional $6.5 billion represents network facilities to enable over 90,000 MW of new generation to interconnect reliably. A summary of projects by status as of Dec. 31, 2020, appears in **Figure 1.3**.The numbers provide a snapshot of one point in time, as with an end-of-year balance sheet. The 2020 totals, and likewise those in **Figure 1.3**, reflect revised cost-estimate changes and project cancellations for previously approved RTEP elements. For example, PJM can recommend canceling a network system enhancement from the RTEP when a queued project driving the need for the network project withdraws from the queue. Withdrawals at this point in the interconnection process are typically driven by developer business decisions, including PJM Reliability Pricing Model (RPM) auction activity, siting challenges, financing challenges or other business model factors.

Supplemental projects are identified and developed by transmission owners to address local reliability needs, including customer service; equipment material condition, performance and risk; operational flexibility and efficiency; and infrastructure resilience. PJM reviews them to evaluate their impact on the regional transmission system. A discussion of supplemental projects, including summaries by driver greater than or equal to $10 million, is included in **Section 3.2**.

Shifting RTEP Dynamics

The $413 million of baseline transmission investment approved during 2020 continues to reflect the shifting dynamics driving transmission expansion. As **Figure 1.4** shows, new large-scale transmission projects (345 kV and above) have become more uncommon as RTO load growth has fallen below one percent. Aging infrastructure, grid resilience, shifting generation mix and more localized reliability needs are now more frequently driving new system enhancements. Much of the new investment that is occurring at 500 kV is to address existing, aging transmission lines, many of which were constructed in the 1960s and earlier.

Figure 1.4: Approved Baseline Projects by Voltage 2017–2020



No baseline projects at the 765 kV level were identified for this time period.

Flat Load Growth

PJM's 2020 RTEP baseline power flow model for study year 2025 was based on the 2020 PJM Load Forecast Report, summarized in **Section 2**, showing a 10-year RTO summer, normalized peak growth rate of 0.6 percent. Average 10-year-annualized summer growth rates for individual PJM zones ranged from -0.5 percent to 1.5 percent. Load forecasts from the past five years reflect broader trends in the U.S. economy and PJM model refinements to capture evolving customer behaviors. These include more efficient manufacturing equipment and home appliances, and distributed energy resources such as behind-the-meter, rooftop solar installations.

Changing Capacity Mix

PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by:

- New generating plants powered by Marcellus and Utica shale natural gas
- New wind and solar units driven by federal and state renewable incentives
- Generating plant deactivations
- Market impacts introduced by demand response and energy efficiency programs

PJM's interconnection process is showing trends of increasing renewable generation. With approximately 105,000 MW of interconnection requests, nearly 59,000 MW, or 56 percent, of all requested interconnection rights were for solar generation. Storage and wind generation types constitute 10.4 percent, 6.3 percent respectively. Renewable generation is not the only changing aspect of PJM's capacity mix. Existing RPM-eligible, natural gas-fired generation capacity greatly exceeds that of coal. Natural gas plants totaling nearly 28,000 MW constitute 27 percent of the generation currently seeking capacity interconnection rights in PJM's new services queue. Solar generation has overtaken natural gas as the largest percentage of units seeking capacity interconnection rights. Solar interconnection requests have more than doubled, by megawatt, in the past year.

More than 30,600 MW of coal-fired generation have deactivated between 2011 and 2020. The economic impacts of environmental public policy, coupled with the age of these plants – many more than 40 years old – make ongoing operation prohibitively expensive. PJM continued to receive deactivation notifications from 10 units totaling 4,428 MW throughout 2020. Approximately 2,500 MW of these announced deactivations were from coal units, with the reaming portion attributable to one nuclear facility. The impacts of deactivation notices received during 2020 are discussed in **Section 3.3.**

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

1.1: Generation in Transition

PJM's 184,395 MW of RPM-eligible existing installed capacity reflects a fuel mix comprising 43 percent natural gas, 27 percent coal and 18 percent nuclear, as shown in **Figure 1.5**. Hydro, wind, solar, oil and waste fuels constitute the remaining 11 percent. Nameplate capacity values represent the full power output of the generators. These values are not limited to RPM eligible installed capacity. A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility.

Totaling over 76,000 MW, renewable fuels are changing the landscape of PJM's interconnection queue. Solar energy comprises 56 percent of the generation in PJM's interconnection queue, a 13 percent increase over the previous year, shown in **Figure 1.6**. An increase in solar generation interconnection requests is attributable to state policies encouraging renewable generation. **Figure 1.6** shows PJM's fuel mix based on requested capacity interconnection rights for generation that was active, under construction or suspended as of Dec. 31, 2020.

Figure 1.5: PJM Existing RPM-Eligible Installed Capacity Mix (Dec. 31, 2020)

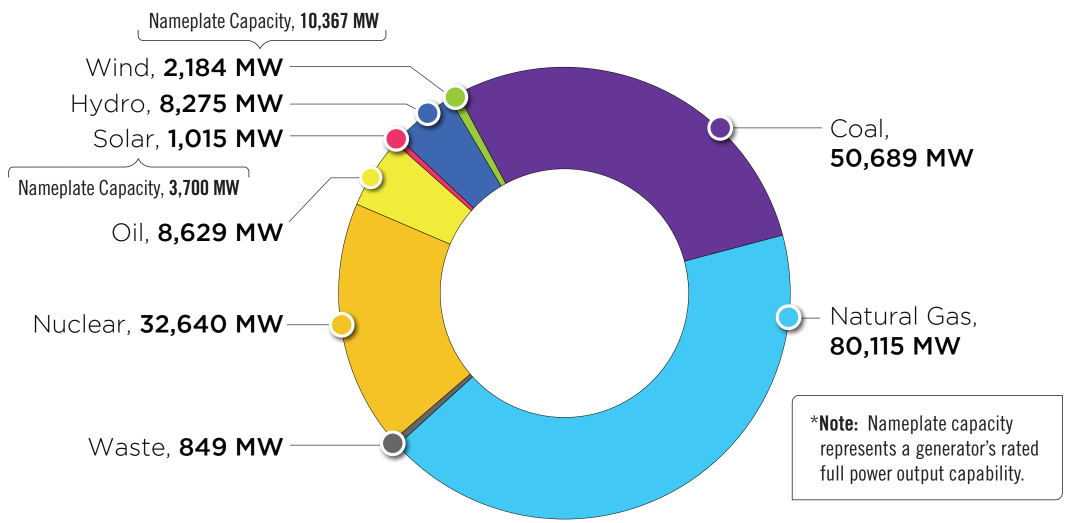


Figure 1.6: Queued Generation Fuel Mix – Requested Capacity Interconnection Rights (Dec. 31, 2020)

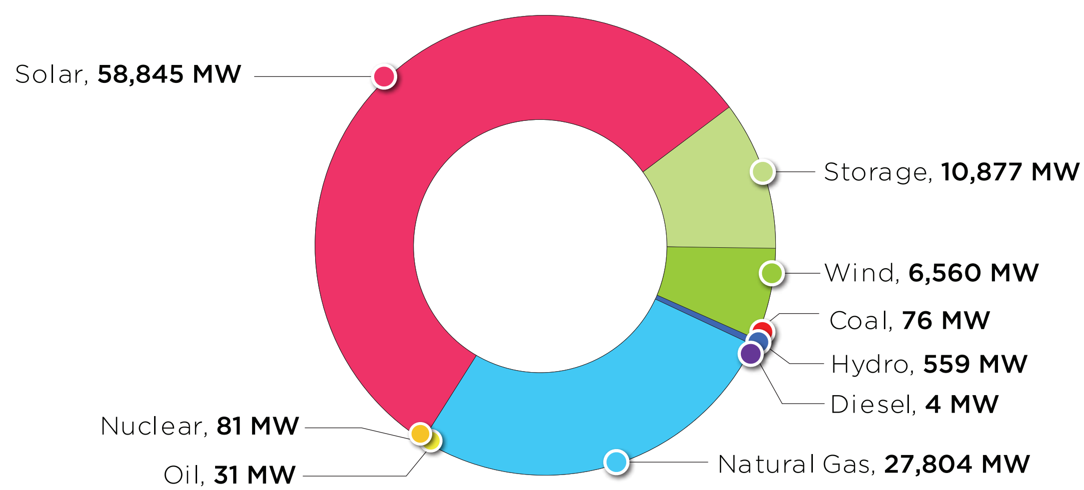


Table 1.1: Requested Capacity Interconnection Rights, Non-Renewable and Renewable Fuels (Dec. 31, 2020)

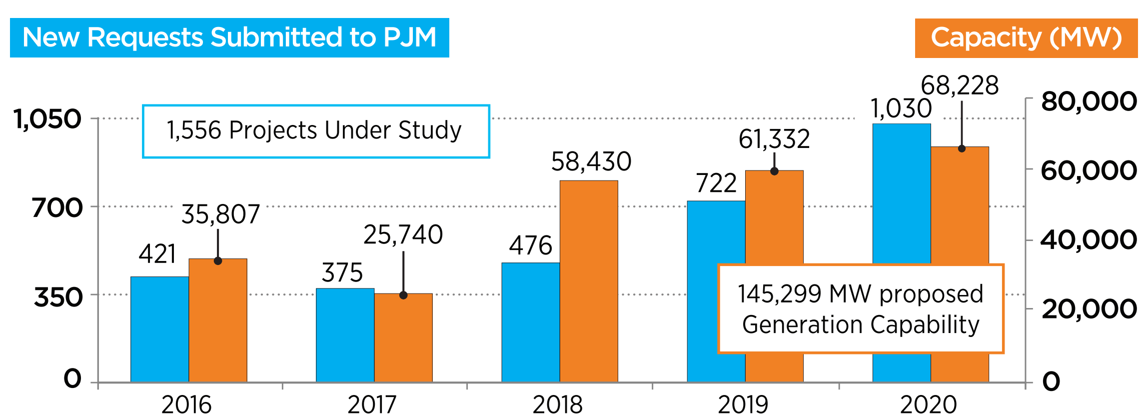
		In Queue						Complete					
		Active		Suspended		Under Construction		In Service		Withdrawn		Grand Total	
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	1	11.0	0	0.0	3	65.0	53	2,146.9	70	33,577.6	127	35,800.5
	Diesel	0	0.0	0	0.0	1	4.1	9	64.4	16	76.7	26	145.2
	Natural Gas	62	10,312.4	9	4,457.0	51	13,034.5	343	48,575.9	659	240,631.2	1,124	317,011.0
	Nuclear	5	37.4	0	0.0	1	44.0	43	3,902.8	22	9,038.0	71	13,022.2
	Oil	3	18.0	0	0.0	8	13.0	18	539.8	22	2,300.0	51	2,870.8
	Other	0	0.0	0	0.0	0	0.0	5	336.5	84	858.8	89	1,195.3
	Storage	250	10,839.5	7	17.6	6	20.0	26	4.0	213	3,730.3	502	14,611.4
Renewable	Biomass	0	0.0	0	0.0	0	0.0	11	252.8	40	896.9	51	1,149.7
	Hydro	7	536.5	0	0.0	2	22.7	32	1,155.9	49	2,146.7	90	3,861.8
	Methane	0	0.0	0	0.0	0	0.0	85	411.8	95	490.1	180	901.8
	Solar	1,120	54,431.2	32	659.1	202	3,754.5	188	1,204.0	1,374	26,271.4	2,916	86,320.3
	Wind	98	6,178.7	6	95.8	11	285.6	105	1,933.2	477	14,300.2	697	22,793.5
	Wood	0	0.0	0	0.0	0	0.0	2	54.0	4	153.0	6	207.0
Other	Battery	1	0.0	0	0.0	0	0.0	0	0.0	0	0.0	1	0.0
	Grand Total	**1,547**	**82,364.7**	**54**	**5,229.6**	**285**	**17,243.4**	**920**	**60,582.0**	**3,125**	**334,470.9**	**5,931**	**499,890.5**

Interconnection requests by fuel type and status for renewable and non-renewable fuels are summarized in **Table 1.1**.

Renewables

PJM's interconnection queue process continues to see renewable-powered generation growth. As **Figure 1.6, Figure 1.7** and **Table 1.1** show, queued requests as of Dec. 31, 2020, for Capacity Interconnection Rights (CIRs) totaled 6,560 MW of wind-powered generators that were actively under study, suspended or under construction. Those CIRs correspond to nameplate capacity totaling 31,809 MW. Queued solar-powered

Figure 1.7: Growth of Renewables in PJM Queue



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generator requests for CIRs totaled 58,845 MW that were actively under study, suspended or under construction. Those CIRs correspond to nameplate capacity totaling 97,585 MW.

Nameplate Capacity vs. Capacity Interconnection Rights

Nameplate capacity represents a generator's rated full power output capability. As **Table 1.2** shows, nameplate capacity is typically much greater than CIRs for wind- and solar-powered generators. This arises from the fact that while some resources can operate continually like conventional fossil-fueled power plants, other renewable resources operate intermittently, such as wind and solar.

Wind turbines can generate electricity only when wind speed is within a range consistent with turbine physical specifications. This presents challenges with respect to real-time operational dispatch and capacity rights. To address the latter concern, PJM has established a set of business rules unique to intermittent resources for determining capacity rights. This value is used to ensure resource adequacy based on the amount of power output PJM can expect from each unit over peak summer hours. PJM business rules permit these values to change as annual operating performance data for individual units is analyzed. Until such time, class averages or specific data provided by the developer establish the amount of CIRs that a unit may request.

Generators powered by intermittent resources – such as wind – frequently require analytical studies unique to their particular characteristics. For example, wind-powered generator requests have clustered in remote areas that are most suitable to their operating characteristics and economics, but they have less access to robust transmission infrastructure. Such an injection of power increases system stress in areas already limited by real-time operating restrictions. Consequently, RTEP studies include complex power-system stability and low-voltage, ride-through analyses.

The interconnection study process is described in PJM Manual 14A, New Services Request Process, available on the PJM website.

Table 1.2: Queued Study Requests (Dec. 31, 2020)

	Projects	Capacity (MW)	Nameplate Capability (MW)
Active	1,547	82,364.7	145,507
In Service	920	60,582.0	72,723
Suspended	54	5,229.6	7,017
Under Construction	285	17,243.4	21,713
Withdrawn	3,125	334,470.9	426,656
Grand Total	**5,931**	**499,890.5**	**673,616**

1.1.1 — New Services Queue Requests

Interconnection Activity

The generation interconnection process has three study phases: feasibility, system impact and facilities studies, to ensure that new resources interconnect without violating established NERC, PJM, transmission owner and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to interconnect and to participate in PJM capacity and energy markets.

Generation Queue Activity

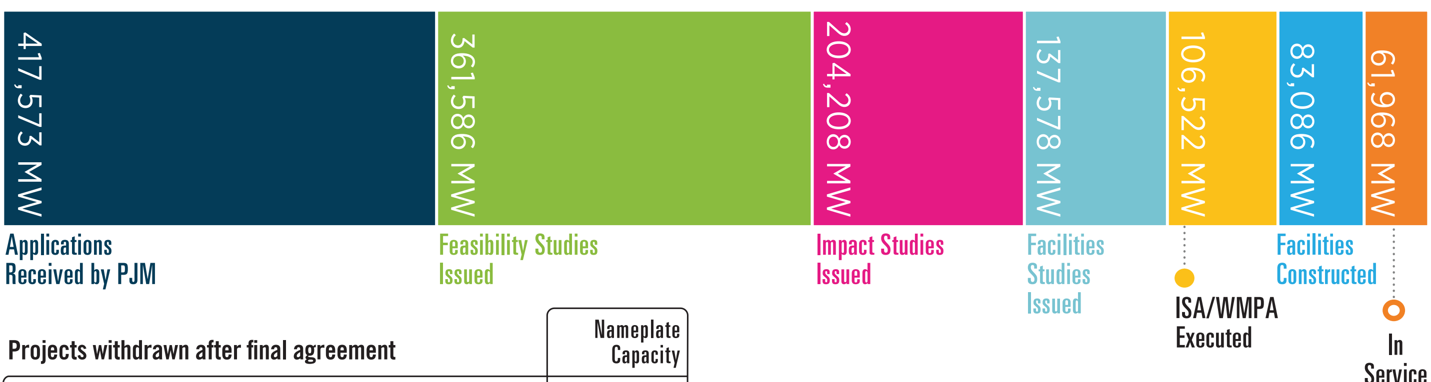
PJM markets have attracted generation proposals totaling 499,891 MW, as shown in **Table 1.2**. Over 82,360 MW of interconnection requests were actively under study and over 22,400 MW were under construction or suspended as of Dec. 31, 2020. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. While withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors.

Queue Progression History

PJM reviews generation queue progression annually to understand overall developer trends and their impact on PJM's interconnection process. **Figure 1.8** shows that for all generation submitted in PJM's Interconnection process through Dec. 31, 2020, only 61,968 MW – 14.8 percent – reached commercial operation. Note that **Figure 1.8** reflects requested capacity interconnection rights that are lower than nameplate capacity given the intermittent operational nature of wind- and solar-powered plants, as described earlier.

Following interconnection service agreement (ISA) or wholesale market participant agreement (WMPA) execution, 22,442 MW of capacity with ISAs and 1,107 MW of capacity with WMPAs withdrew from PJM's interconnection process. Overall, 23 percent of requests by project reach commercial operation, whereas only 15 percent of requests by megawatt reach commercial operation.

Figure 1.8: Queued Generation Progression – Requested Capacity Rights (Dec. 31, 2020)



Projects withdrawn after final agreement

			Nameplate Capacity
177	Interconnection Service Agreements	**22,442** MW	30,294 MW
291	Wholesale Market Participation Agreements	**1,107** MW	2,293 MW

Percentage of planned capacity and projects that have reached commercial operation	15% Requested capacity megawatts	23% Requested projects

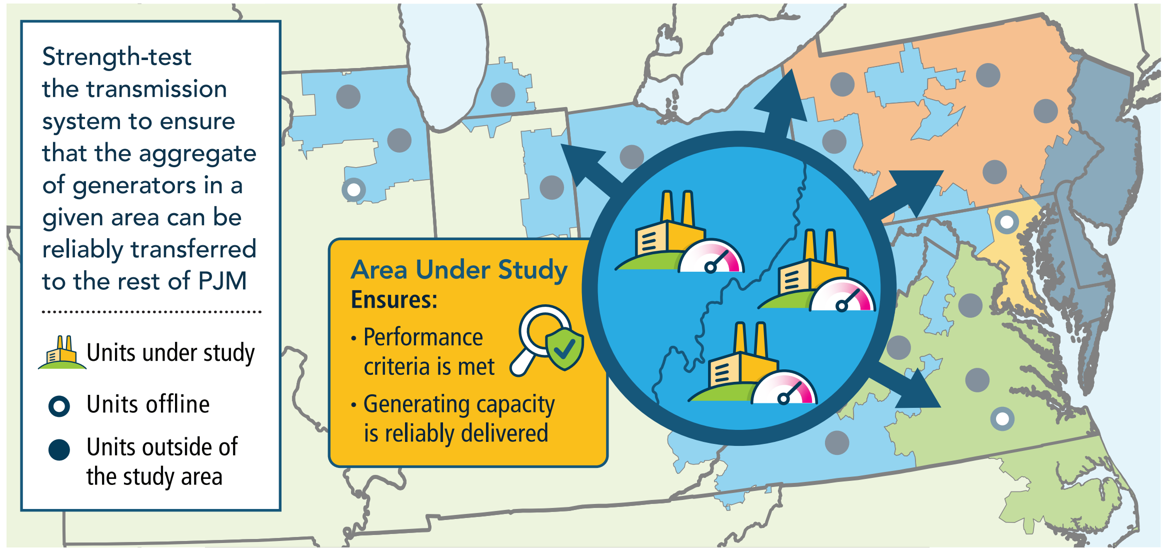
This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2020.

Interconnecting Reliably

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. The PJM Board has approved network facility reinforcements totaling $6.5 billion to interconnect over 90,000 MW of new generating resources and satisfy other new service requests – merchant transmission interconnection, for example. The PJM Board approved 55 new network system enhancements totaling over $101 million in 2020 alone.

As described in **Section 1.2**, PJM tests for compliance with all reliability criteria imposed by the NERC and PJM regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies the system conditions to be evaluated that sufficiently stress the transmission system to ensure that the transmission system meets the performance criteria specified in the standards. PJM's generator deliverability test ensures that sufficient transmission capability exists to deliver generating capacity reliably from a defined generator or area to the rest of PJM load, as illustrated in **Figure 1.9**.

Figure 1.9: Generator Deliverability Concept



Deactivations

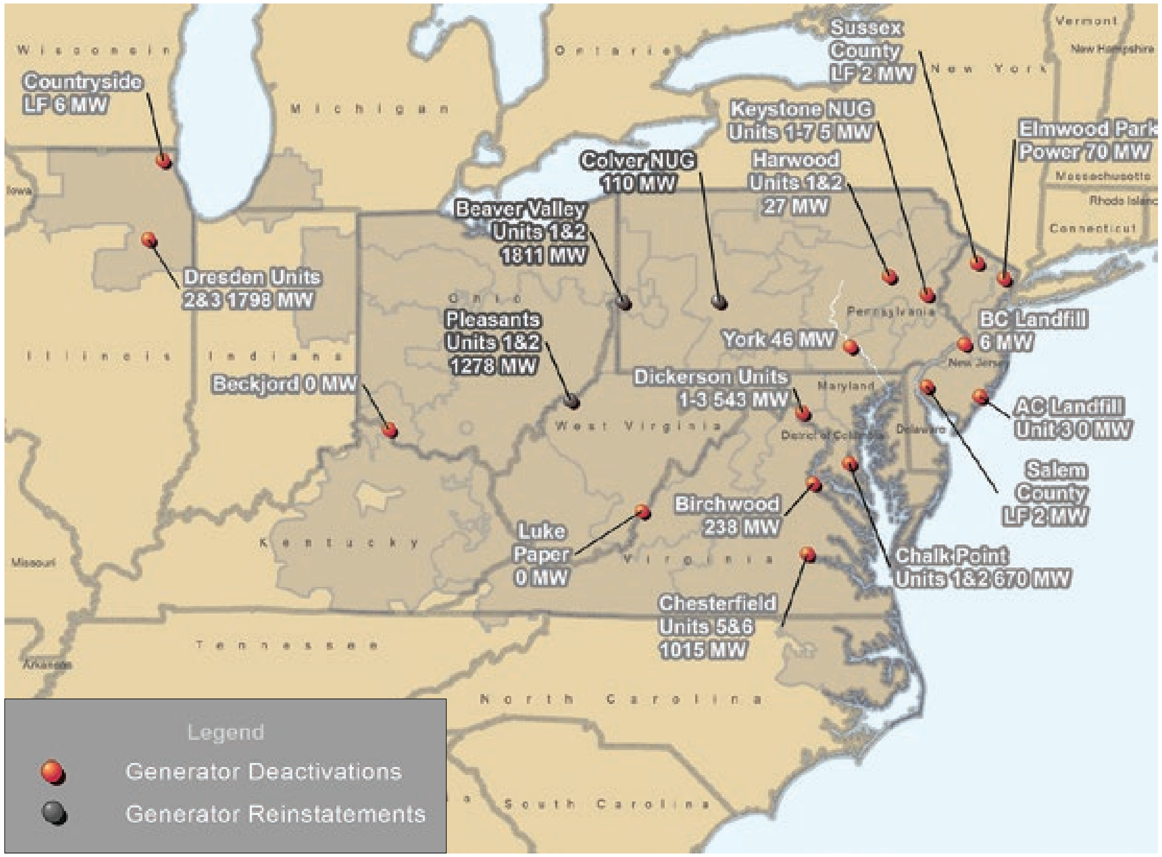
PJM received 22 deactivation notifications in 2020 totaling 4,428 MW, down from the previous eight years. **Map 1.2** shows the deactivation request locations received in 2020.

Generator owners requested the deactivation of these units to take place between June 2020 and May 2023. PJM maintains a list of formally [submitted deactivation notifications](), available on the PJM website.

PJM has 30 days in which to respond to a generator owner with deactivation study results. Generator deactivations alter power flows that can cause transmission line overloads and, given reductions in system reactive support from those generators, undermine voltage support. Deactivation reliability studies comprise thermal and voltage analysis, including generator deliverability, common mode outage, N-1-1 analysis and load deliverability tests. Solutions to address reliability violations resulting from generator deactivations may include upgrades to existing facilities, scope expansion for current baseline projects already in the RTEP, or construction of new transmission facilities. In some instances, potential reliability criteria violations identified through a deactivation study can be solved by RTEP enhancements already approved by the PJM Board and included in the RTEP.

Actual deactivations in 2020 included 29 units for a total of nearly 3,300 MW.

Map 1.2: PJM Generator Deactivation Notifications Received Jan 1, 2020 through Dec. 31, 2020)



PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

1.2: Baseline Project Drivers

NERC Criteria – RTEP Perspective

PJM's RTEP process rigorously applies NERC Planning Standard TPL-001-4 through a wide range of reliability analyses – including load and generation deliverability tests – over a 15-year planning horizon. PJM documents all instances where the system does not meet applicable reliability standards and develops system reinforcements to ensure compliance. NERC penalties for violation of a standard can be as high as $1 million per violation, per day.

PJM addresses transmission expansion planning from a regional perspective, spanning transmission owner zonal boundaries and state boundaries to address the comprehensive impact of many system enhancement drivers, including NERC reliability criteria violations. Reliability criteria violations can also occur locally, in a given transmission owner zone, driven by an issue in that same zone. Violations may also be driven by some combination of local and regional factors.

Bulk Electric System Facilities

NERC's planning standards apply to all bulk electric system (BES) facilities, defined by ReliabilityFirst Corp. and the SERC Reliability Corp. to include all of the following power system elements:

1. Individual generation resources larger than 20 MVA, or a generation plant with aggregate capacity greater than 75 MVA that is connected via step-up transformer(s) to facilities operated at voltages of 100 kV or higher
2. Lines operated at voltages of 100 kV or higher
3. Associated auxiliary and protection and control system equipment that could automatically trip a BES facility, independent of the protection and control equipment's voltage level (assuming correct operation of the equipment)

The ReliabilityFirst definition of BES excludes the following:

1. Radial facilities connected to load-serving facilities, or individual generation resources smaller than 20 MVA, or a generation plant with aggregate capacity less than 75 MVA where the failure of the radial facilities will not adversely affect the reliable steady-state operation of other facilities operated at voltages of 100 kV or higher
2. The balance of generating plant control and operation functions (other than protection systems that directly control the unit itself and its associated step-up transformer) would include relays and systems that automatically trip a unit for boiler, turbine, environmental and/or other plant restrictions
3. All other facilities operated at voltages below 100 kV

Given this BES definition, PJM conducts reliability analyses on PJM Tariff facilities, which may include facilities below 100 kV, to ensure system compliance with NERC Standard TPL-001-4. If PJM identifies violations, it develops transmission expansion solutions to solve them, as part of its RTEP window process.

NERC Reliability Standard TPL-001-4

Under NERC Reliability Standard TPL-001-4, "planning events" – as NERC refers to them – are categorized as P0 through P7 and defined in the context of system contingency. PJM studies each event as part of one or more steady-state analyses as described in PJM Manual 14B, PJM Region Transmission Planning Process, available on the PJM website.

- P0 – No Contingency
- P1 – Single Contingency
- P2 – Common Mode Contingency (bus section)
- P3 – Multiple Contingency (two overlapping singles)
- P4 – Common Mode Contingency (fault plus stuck breaker)
- P5 – Common Mode Contingency (fault plus relay failure to operate)
- P6 – Multiple Contingency (two overlapping singles)
- P7 – Common Mode Contingency (common structure)

Consistent with NERC definitions, if an event comprises an equipment fault such that the physical design of connections or breaker arrangements also takes additional facilities out of service, then they are taken out of service as well. For example, if a transformer is tapped off a line without a breaker, both the line and transformer are removed from service as a single contingency event.

PJM N-0 analysis – shown in **Table 1.3** as a NERC planning event and is mapped to planning event P0 – examines the BES as is, with all facilities in service. PJM identifies facilities that have pre-contingency loadings that exceed applicable normal thermal ratings. Additionally, bus voltages that violate established limits are specified in PJM Manual 3, Transmission Operations, available on the PJM website.

Similarly, N-1 analysis – mapped to planning event P1 – requires that BES facilities be tested for the loss of a single generator, transmission line or transformer. Likewise, bus voltages that exceed limits specified by PJM Manual 3 are also identified. Generator and load deliverability tests are also applied to event P1.

PJM N-1-1 analysis – mapped to planning events P3 and P6 – examines the impact of two successive N-1 events with re-dispatch and system adjustment prior to the second event. Monitored facilities must remain within normal thermal and voltage limits after the first N-1 contingency and re-dispatch within applicable emergency thermal ratings and voltage limits after the second contingency as specified in PJM Manual 3.

PJM's N-2 multiple contingency and common mode analyses evaluate planning events P2, P4, P5 and P7 to look at the loss of multiple facilities that share a common element or system protection arrangement. These include bus faults, breaker failures, double-circuit tower line outages and stuck breaker events. N-2 analysis is conducted on the basecase itself.

Common mode analysis is conducted within the context of PJM's deliverability testing methods, discussed in PJM Manual 14B, PJM Region Transmission Planning Process, available on the PJM website.

NERC Standard TPL-001-4 includes extreme events as well. PJM studies system conditions following a number of extreme events, also known as maximum credible disturbances, judged to be critical from an operational perspective for risk and consequences to the system.

Table 1.3: Mapping RTEP Analysis to NERC Planning Events

Steady-State Analysis	NERC Planning Events
Basecase N-0 – No Contingency Analysis	P0
Basecase N-1 – Single Contingency Analysis	P1
Basecase N-2 – Multiple Contingency Analysis	P2, P4, P5, P7
N-1-1 Analysis	P3, P6
Generator Deliverability	P0, P1
Common Mode Outage Procedure	P2, P4, P5, P7
Load Deliverability	P0, P1
Light-Load Reliability Criteria	P1, P2, P4, P5, P7

Stability Requirements

PJM conducts stability studies to ensure that the planned system can withstand NERC criteria disturbances and maintain stable operation throughout PJM's planning horizon. NERC criteria disturbances are those required by the NERC planning criteria applicable to system-normal, single-element outage and common-mode, multiple-element outage conditions.

A key aspect of NERC Reliability Standard TPL-001-4 also calls for modeling the dynamic behavior of loads as part of stability analysis at peak load levels. Prior to TPL-001-4 standard implementation, stability analyses were conducted on static load models that may not necessarily have captured the dynamic nature of real and reactive components of system loads and energy-efficient loads. From an analytical perspective, this requirement enhances analysis of fault-induced, delayed voltage recovery or changes in load characteristics like that of more energy-efficient loads.

Transmission Owner Criteria

The PJM Operating Agreement specifies that individual transmission owner (TO) planning criteria are to be evaluated as a part of the RTEP process, in addition to NERC and PJM regional criteria. Frequently, TO planning criteria address specific local system conditions, such as in urban areas. TOs are required to include their individual criteria as part of their respective FERC Form 715 filings. TO criteria can be found on the PJM website.

As part of its RTEP process, PJM applies TO criteria to the respective facilities that are included in the PJM Open Access Transmission Tariff (OATT) facility list. Transmission enhancements driven by TO criteria are considered RTEP baseline projects, and are eligible for proposal window consideration, as shown in **Figure 1.10**. (Starting Jan. 1, 2020, TO criteria projects will be included in PJMs competitive proposal process.)

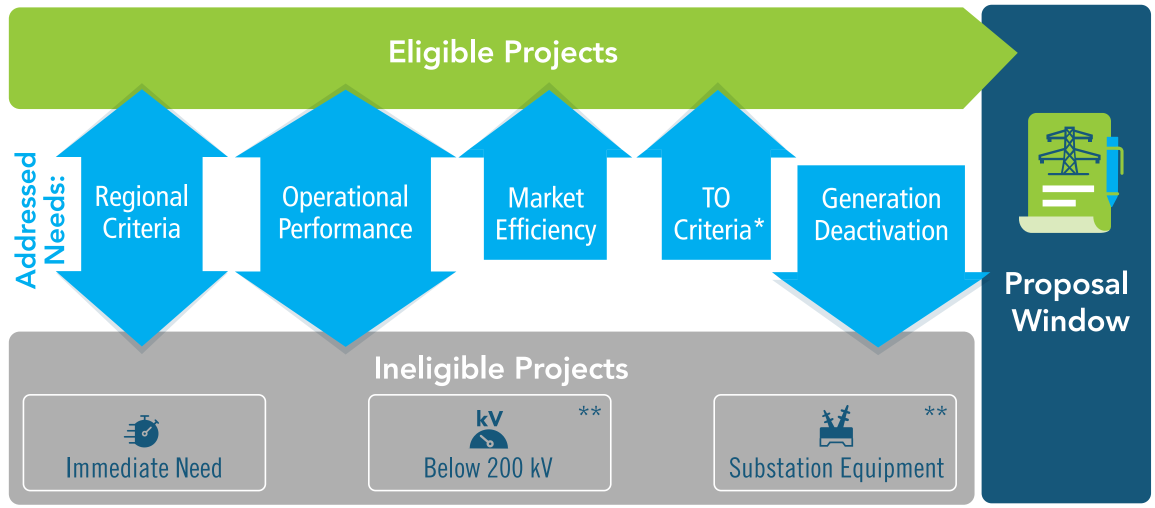
2020 Transmission Owner Criteria-Driven Projects

PJM has observed that TO aging infrastructure criteria drive the need for supplemental projects. Review of facilities built in the 1960s and earlier have revealed significant deterioration. Planning for aging infrastructure is not new to PJM. Spare 500/230 kV transformers, aging 500 kV line rebuilds and other equipment enhancements approved in prior years are already part of the RTEP.

In other instances, TO criteria encompass local loss-of-load thresholds, particularly on radial facilities. The threshold for some is on a megawatt-mile basis, others on a megawatt-magnitude basis to reduce the extent of load impacted.

Section 3.1 summarizes TO criteria-driven transmission projects with cost estimates greater than or equal to $10 million, as approved by the PJM Board in 2020.

Figure 1.10: RTEP Proposal Window Eligibility



Note: **TO Criteria is eligible for proposal windows as of Jan. 1, 2020.*

***Projects below 200 kV and substation equipment projects could become eligible for competition if multiple needs share common geography/contingency or if the project has multi-zonal cost allocation.*

Developing Transmission Solutions

After PJM identifies a baseline transmission need, including market efficiency, PJM may open a competitive proposal window, depending on the required in-service date, voltage level and scope of likely projects. Window eligibility for project driver types is shown in **Figure 1.10**. Throughout each RTEP window, developers can submit project proposals to address one or more needs. When a window closes, PJM evaluates each proposal to determine if any meet all of our project requirements. If so, PJM then recommends a proposal to the PJM Board. When the Board approves a proposal, the designated developer becomes responsible for project construction, ownership, operation, maintenance and financing.

2020 Baseline Project Drivers

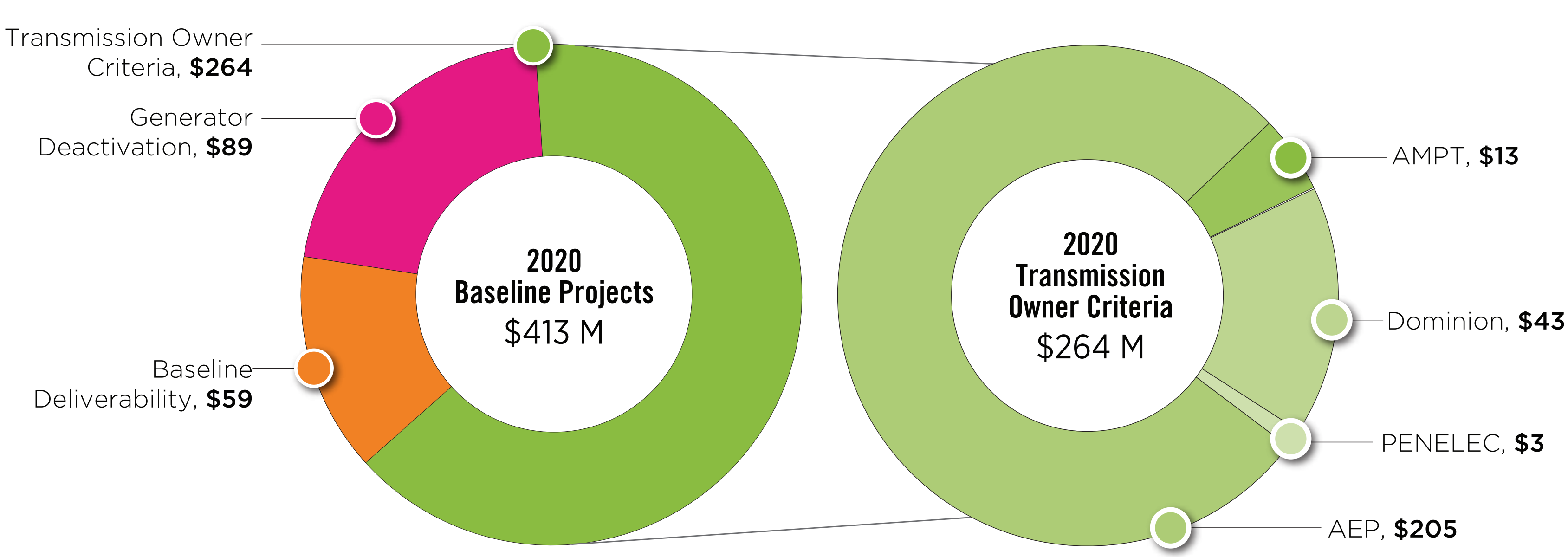
PJM RTEP baseline analysis identifies the need for transmission enhancement projects that span a range of drivers. Those projects identified by PJM and approved by the PJM Board in 2020 were no different, as discussed in later sections of this report and summarized in **Figure 1.11**. As the figure shows, baseline transmission investment, once primarily comprising projects driven by deliverability, now also comprises projects driven by other factors, including transmission owner criteria.

Market Efficiency

PJM's RTEP process includes a market efficiency analysis to accomplish the following goals:

- Determine which reliability-based enhancements have economic benefit if accelerated

Figure 1.11: 2020 RTEP Baseline Project Driver ($ Million)

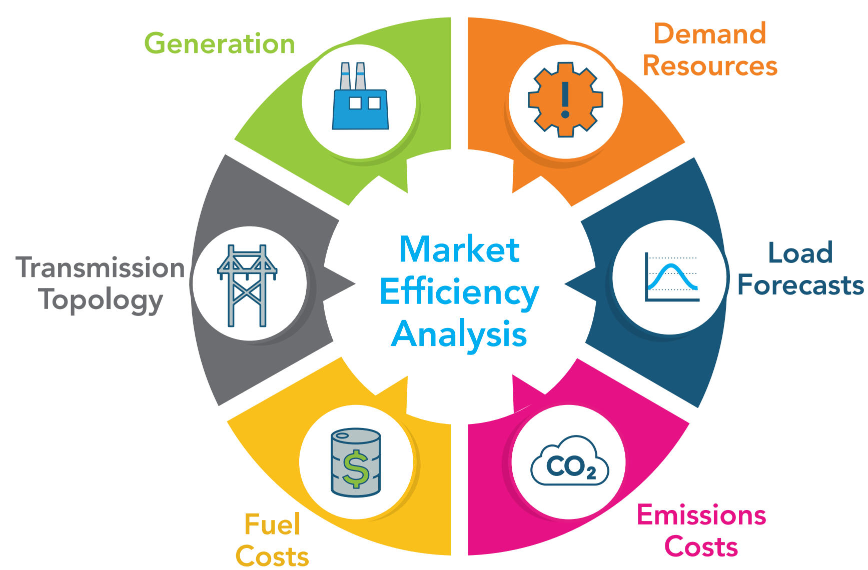


- Identify new transmission enhancements that may realize economic benefit
- Identify the economic benefits associated with reliability-based enhancements already included in the RTEP that, if modified, would relieve one or more congestion constraints, providing additional economic benefit

PJM identifies the economic benefit of proposed transmission projects by conducting production-cost simulations accounting for the concepts in **Figure 1.12**. These simulations show the extent to which congestion is mitigated by a project for specific study-year transmission and generation dispatch scenarios. Economic benefit is determined by comparing future-year simulations both with and without the proposed transmission enhancement.

The metrics and methods used to determine economic benefit are described in **Section 4.3**.

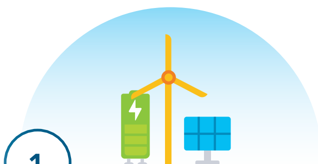
Figure 1.12: Market Efficiency Analysis Parameters



1.3: Grid of the Future

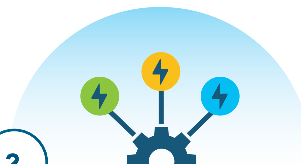
1.3.1 — Overview

PJM's RTEP process continues to evolve, bringing into clearer focus the grid of the future, one driven by decarbonization, renewables, public policy, resource mix and new infrastructure technologies. Strategically over the next five years, PJM will continue to focus on three key trends:



1

Growing renewable energy resources – including offshore wind – are driven by federal and state environmental policy goals, as well as industry goals, to achieve decarbonization and other clean air mandates. PJM's interconnection queue includes more than 140,000 MW, of which 88 percent is wind, solar or battery. Several PJM coastal states have specific offshore wind generation goals totaling more than 14,000 MW by 2035. The first offshore wind facility in PJM became operational in September 2020 – Virginia's 12 MW pilot project, consisting of two 6 MW turbines.



2

Growing distributed energy resources (DER) – like rooftop solar – are driven by customer preference for green energy solutions, lower energy bills and "distributed resilience" in the face of extreme weather and other severe external events. State and federal policies, along with technological advancements and customer demand, may result in the penetration of millions of DER. The lines between generation, transmission and distribution are thus becoming less distinct. The scope and means by which PJM affects operational control of generation and load will change.

3

Aging infrastructure – 30 percent of which is over 50 years old – continues to require replacement with new assets that embrace new technologies. Modernizing the existing transmission system will provide benefits, including designs that can withstand more extreme events, lower the frequency and duration of outages, reduce public and employee safety risks, and use advanced technology to improve system operability, efficiency and security.

On the basis of these trends, PJM has already begun to integrate RTEP changes in generation, transmission and load forecasting processes with innovative thinking and technologies, as discussed below. Such change, though, will not move forward in a vacuum. A solid foundation of reliability will remain paramount with a growing focus on integrating greater resilience into PJM's existing reliability standards by which the grid of the future is planned and operated.

Figure 1.13: Strategic Pillars

1.3.2 — Evolving Interconnection Process

Given the magnitude of renewable generation interconnection requests that PJM continues to see in each successive queue, a grid of the future necessarily entails revisiting the interconnection component of the RTEP process. That effort is underway. On Oct. 30, 2020, PJM conducted the first of four interconnection process stakeholder workshops, beginning an initiative to promote greater efficiency and effectiveness. The process improvement work ahead will address how to most efficiently reduce current queue backlogs, while also looking at ways to improve the overall process for future interconnection requests.

In particular, the growth in smaller, renewable generation resources is driving a significant increase in individual interconnection request volume. In 2020, for example, PJM received 970 new service requests, more than double the 470 new service requests received two years prior and the most in its history. PJM's ability to efficiently process interconnection requests is critical to the development of those resources. The workshops are part of PJM's effort to serve a fast-changing grid by seeking ways to remove process barriers to increasing volume of renewable resources.

Exploring Ways Forward

Following educational, level-setting presentations at the first session on Oct. 30, stakeholders presented some 200 suggestions, concerns and comments at the second workshop held on Dec. 11, 2020. PJM distilled that stakeholder input into 12 categories: transparency, queue window scheduling, application process, basecase, studies, affected system, cost responsibility, agreements, interim operation, construction, disputes and staffing, as presented at the third workshop on Jan. 29, 2021. Some suggestions have already been incorporated by PJM or have been in progress. Many suggestions will require at least stakeholder endorsement; some will require changes in FERC policy. The fourth workshop, scheduled for March 4, 2021, will explore ways to move forward.

1.3.3 — Offshore Wind

PJM's grid of the future embraces continued commitment to states to advance their renewable power public policy objectives and achieve greater decarbonization. Regionally, the area off PJM Atlantic Coast states has the potential to yield thousands of megawatts of wind-powered energy. Efficiently harnessing that energy through the construction of offshore wind farms will require the development of robust transmission to deliver power onshore to PJM markets. To do so, PJM is collaborating with coastal states to implement its Operating Agreement RTEP Process State Agreement Approach (SAA) to help states achieve RPS policy objectives.

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State Agreement Approach

Historically, baseline projects have been driven by reliability criteria, market efficiency needs and TO criteria requirements. PJM's SAA, authorized by FERC, expands the planning process to enable a state, or group of states, to propose a project to advance public policy requirements as long as the states involved agree to pay all costs of any related build-out included in the RTEP. The SAA was developed seven years ago after extensive consultation with the Organization of PJM States (OPSI) as part of implementing FERC's Order 1000. In that order, FERC required regional grid operators to "provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes."

New Jersey Initiative

The New Jersey Board of Public Utilities on Nov. 18, 2020, announced an initiative to implement the SAA to achieve its offshore wind policy objectives. New Jersey's transmission needs will be part of a competitive proposal window anticipated to open in the first quarter of 2021. Transmission developers may submit proposals to facilitate New Jersey's goal to deliver up to 7,500 MW of offshore wind to consumers by 2035, as discussed further in **Section 5.0.3.**

NOTE:

Nov. 18, 2020 NJBPU Offshore Wind Order.

Multi-State Offshore Wind Study

PJM is also preparing to conduct a scenario study in 2021 that will examine, more broadly, system impacts from offshore wind development. The study will provide a significant opportunity to build collaborative relationships with state commissions that are actively implementing renewable portfolio standard targets. The outcome of the study will summarize grid impacts and associated estimated transmission costs to assist states in their decisions.

1.3.4 — Capacity Value of Intermittent Resources

PJM continues to witness extraordinary growth in energy storage and intermittent generating resources such as wind, solar and other renewable resources. Indeed, PJM's interconnection queue demonstrates that such growth is expected to continue unabated for some years to come, as discussed in **Section 5**. As PJM's resource mix evolution continues to include more of this generation, the manner in which PJM evaluates the contribution of such resources toward resource capacity value also needs to evolve.

Prior to 2021, PJM calculated the resource capacity value of an intermittent resource, and that which historically has been labeled as "limited duration," by a methodology independent of changes to the overall resource mix. This meant that a resource's capacity capability and its contribution toward meeting PJM's resource adequacy requirements would not have been impacted by the amount of renewables and energy storage within the RTO as a whole.

This began to draw PJM attention and concern in 2018, given that increasing amounts of intermittent and limited-duration resources impact hourly loss-of-load probability (LOLP) risk profile. Without recognizing this dynamic, PJM may be over or under valuing intermittent and limited-duration resource contribution to resource adequacy over time.

Effective Load Carrying Capability

Prior to 2021, intermittent resource capacity value was set at a resource's average output over a defined number of summer peak load hours. This approach has two limitations. One, it weights the output over all hours equally, regardless of an individual hour's actual contribution to the

NOTE:

Limited-duration resources have limited-duration capability. These include, but are not limited to, energy storage resources that receive energy from the grid and store the energy for later injection into the grid: e.g., pumped storage hydro units, compressed air energy storage units, flywheel energy storage units, battery storage units and hydroelectric generating units with reservoir storage capability.

Intermittent Resources are generating units with output that varies as a function of an energy source that is non-continuous and that cannot be directly controlled. Such resources are unable to provide a stated level of output on demand and are unable to maintain a stated level of output for any specified period of time. Intermittent resources include, but are not limited to, wind units, solar units, run-of-river hydroelectric units (without reservoir storage capability) and landfill gas units (without alternate fuel capability).

annual loss of load risk, and, two, it fails to recognize the saturation effect as the amount of intermittent resources in PJM increases. To address these two limitations, PJM performed analysis to assess the reliability value of intermittent resources by using an effective load carrying capability (ELCC) methodology. This more robust methodology recognizes the full value of a resource's output over high-load risk hours and also accounts for the saturation effect.

As part of the process to implement the ELCC, a proposal was developed by the PJM Capacity Capability Senior Task Force (CCSTF) and endorsed by the Markets & Reliability Committee and Members Committee on Sept. 17, 2020. PJM now requires generation owners of ELCC resources to provide specific information about their resources. This information is used by PJM as input to its resource adequacy model.

Pending FERC approval, the ELCC methodology will be applied to intermittent, limited-duration and hybrid resources beginning with the 2023/2024 Delivery Year.

1.3.5 — Distributed Energy Resources

Distributed energy resources (DER) continue to introduce another dynamic into PJM's grid of the future planning process. DER can remain on the customer's side of the meter or participate in PJM markets. DER seeking to participate in PJM's wholesale capacity market must do so via PJM's RTEP new services queue process. This ensures that necessary transmission improvements are in place to preserve reliability and that market participation contracts are executed. Distributed energy devices like rooftop solar remain behind the meter and do not participate in PJM capacity markets. Nonetheless, they impact the demand side of PJM resource adequacy by offsetting load.

FERC Order 2222

The Federal Energy Regulatory Commission (FERC) issued Order 2222 in Docket No. RM18-9-000 on Sept. 17, 2020. The intent of the Order is to remove barriers to entry for smaller-scale generation and storage on the distribution system, along with demand response and energy efficiency, by allowing DER to aggregate and directly compete against larger, more conventional generation in PJM markets. PJM continues to evaluate any potential impacts to its load forecasting process, interconnection process and transmission planning process.

1.3.6 — Aging Infrastructure

The regional high-voltage transmission system is aging, posing a reliability risk to the grid. Many facilities were placed in service in the 1960s and earlier. Many 500 kV lines were constructed in the 1960s; 230 kV and 115 kV lines date to the 1950s and earlier. They are deteriorating and reaching the end of their useful lives. Maintaining older equipment means higher costs to address the greater reliability risk associated with greater probability of facility outages. Addressing this deterioration and the associated costs and risks is part of each transmission owner's broader asset management strategy in parallel with the PJM RTEP process.

NOTE:

PJM is currently seeking feedback from stakeholders, including states and distribution utilities, and developing a proposal to comply with **FERC Order No. 2222**. Submittal of a compliance filing is expected by July 19, 2021.

As equipment continues to age, the approach is shifting from simply maintaining assets to replacing and modernizing them. Asset modernization has gone beyond replacement. Replacement projects offer the opportunity to learn from history and adopt new knowledge, capabilities and technologies that did not exist when original facilities were built.

1.3.7 — Embracing Innovative Industry Technologies

The industry landscape is changing with unparalleled speed in ways impacting PJM as never before. Innovation is empowering all sectors of the industry with more choices as to how electricity is generated, transmitted and used. The outcome of these choices and means by which PJM incorporates them is creating the grid of the future. PJM continues to monitor industry trends and pursue those that will create value for stakeholders.

Energy Storage Resources

Energy storage continues to grow in PJM. Efficient grid operations in an era experiencing rapid growth of intermittent renewable resources will require increased electric system flexibility. Energy storage provides grid operators the ability to meet load requirements when wind, solar and other intermittent resources must alter power output because of weather conditions, or because those units simply are unavailable. Energy storage resources can also improve transmission system efficiency by increasing network utilization factors. PJM has worked with several industry entities including the DOE national laboratories to advance the use of energy storage and ensure that PJM's wholesale market is capable of allowing all forms of energy storage technology to participate competitively.

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Storage as Transmission Asset in Regional Planning

PJM, in collaboration with stakeholders, in 2020 continued to explore how storage assets could be included as part of PJM's RTEP process to reinforce the transmission system. Discussions under the auspices of the PJM Planning Committee have yielded proposed evaluation, performance and criteria requirements to ensure compliance with NERC and PJM standards.

Electric Vehicles

PJM continues to pay close attention to U.S. transportation sector electrification and, in particular, the impact of electric vehicles (EV) on transmission system needs. The Edison Electric Institute estimates that EVs will grow from one million today to seven million across the country by 2025. EVs would operate essentially in two modes, potentially based on economic signals sent by PJM:

- Charge on-board batteries from electricity purchased from PJM's Energy Market at distributed charging stations
- Discharge power to the grid to earn revenue in PJM markets for energy and related ancillary services, similar to a generation asset

In either mode, PJM must ensure that transmission capability is in place to accommodate the additional flow of power to charging stations, expected to be highly distributed across local and interstate highway systems. The timing of the coincident effect of EV's charging cycles could also drive the need for additional generating resources and related transmission, particularly during peak load periods. This transmission need is amplified if the power needed to charge EV batteries is expected to come from wind and natural gas-fired generating resources, often distant from the population centers they serve.

Impacts to PJM Load Forecast

As part of its 2020 Load Forecast Report, PJM began to incorporate an explicit adjustment for plug-in electric vehicle charging in its peak and energy forecasts. PJM must ensure that it accounts for EV load in its power flow models in order that reliability studies are conducted with greater accuracy as the number of EVs continues to grow.

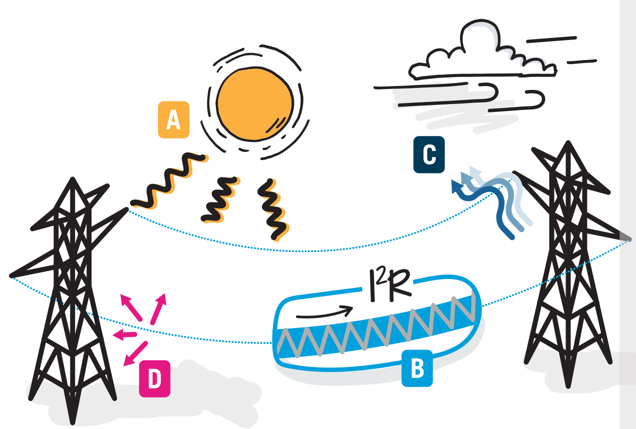
Dynamic Line Ratings

Dynamic Line Rating (DLR) technology – illustrated in **Figure 1.14** – uses advanced sensors and software to monitor real-time ambient temperature, wind speed and conductor tension, and from these data points, determines real-time thermal ratings more frequently than conventional ambient-adjusted temperature ratings in use today. DLR uses real-time measurements to calculate an actual rating for transmission lines based on real-time environmental conditions, versus static ratings. DLR technology can identify additional capacity on transmission lines to relieve congestion and create greater economic efficiencies. Such technology also contributes to system resilience by providing better monitoring of real-time transmission capability.

NOTE:

PJM will continue to work with stakeholders to integrate Storage As a Transmission Asset as part of the PJM RTEP in 2021.

Figure 1.14: Illustration of Dynamic Line Rating Technology



A **Solar heating –** Just as the sun warms the air and the Earth's surface, heat from the sun's rays will raise the temperature at the conductor's surface.

B **Resistive heating –** As current passes through the conductor, heat is generated inside the conductor by electrical losses.

C **Convective cooling –** Nearby wind carries away warm air surrounding the conductor and can cause a dramatic cooling effect along the transmission line.

D **Radiative Cooling –** Even with no wind, transmission lines lose a portion of their heat to cooler ambient air.

Phasor Measurement Unit Implementation

Since 2009, PJM and its member transmission owners have deployed more than 400 phasor measurement units (PMUs) across the PJM transmission system at more than 120 substations in 10 states, shown on **Map 1.3**. In late 2015, PJM and stakeholders developed a new PMU placement requirement to be included in the generation interconnection queue process. This requirement was put in place to ensure continued expansion of this valuable technology beyond its initial rollout. PMUs – shown geographically in **Figure 1.15** – provide data at a higher resolution and much higher reporting frequency than traditional SCADA (supervisory control and data acquisition) systems, painting a more detailed picture of the status of the grid at any given moment. PJM is developing advanced applications of this technology to improve power system efficiency, reliability and resilience. Investment in PMUs across the system provides operators significantly enhanced means to detect and address instability before it causes service interruptions.

Implementation in PJM

From PJM's perspective, full synchrophasor observability of all EHV equipment at 100 kV and above will provide the ability to detect high-speed grid disturbances – oscillations and cascading equipment failures. In

NOTE:

PJM's technical guidelines for installation of synchrophasor measurement equipment at generation facilities can be found on the PJM website.

Map 1.3: Location of Phasor Measurement Units Across PJM

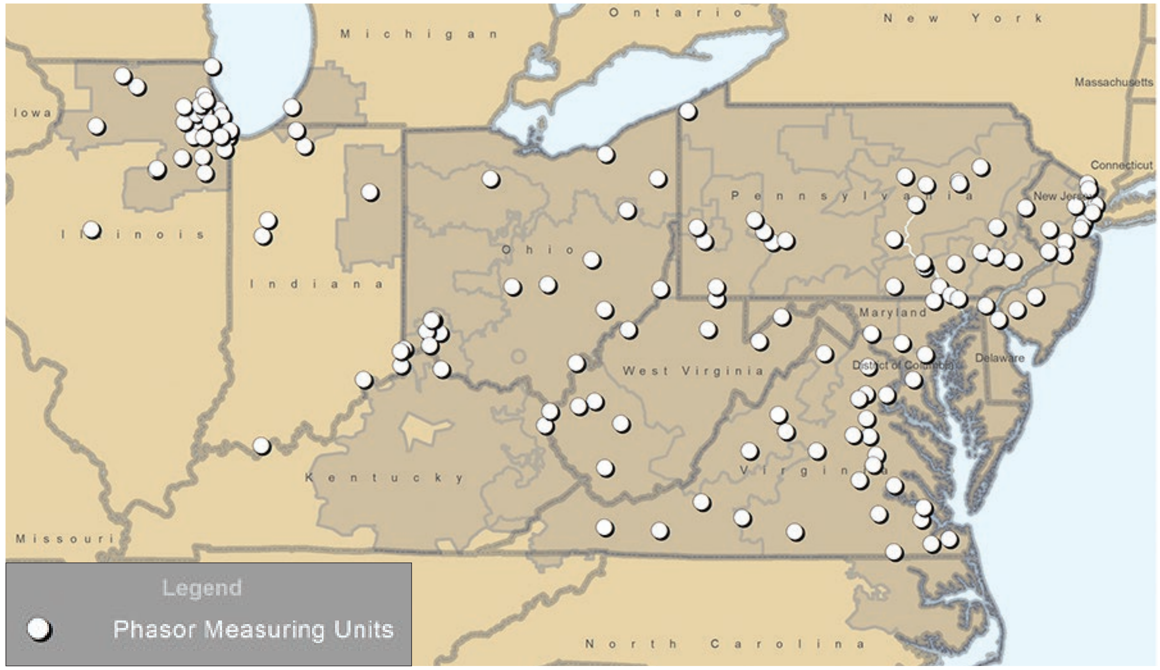
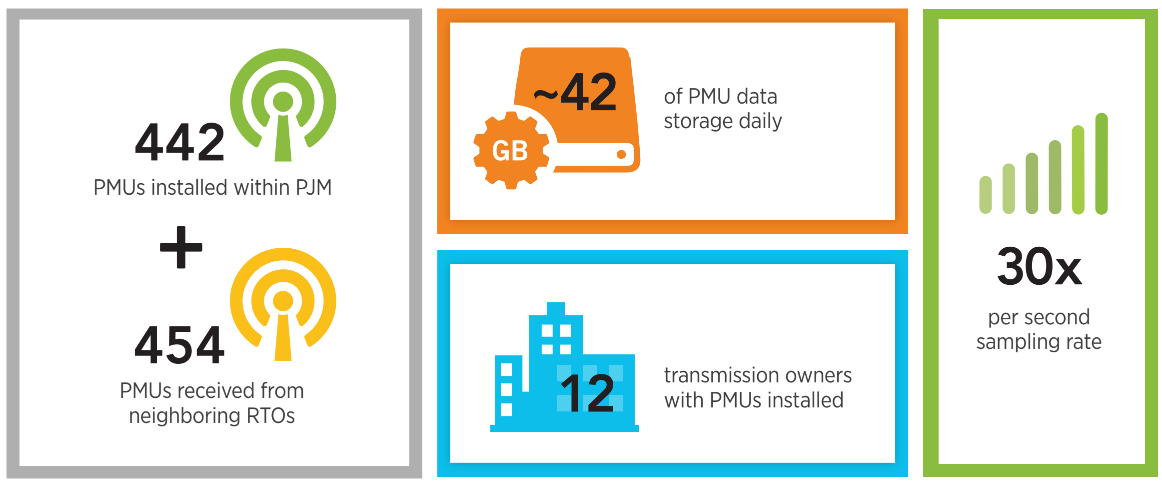


Figure 1.15: Using Phasor Measurement Units in PJM



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addition, this data will provide the means for planners to conduct innovative post-event analysis and dynamic model validation.

To that end, PJM worked with the Planning Committee and Operating Committee in 2020 to incorporate PMU placement into the PJM planning process in Manuals 1, "Control Center and Data Exchange Requirements," and 14B, "PJM Region Transmission Planning Process." For substations with three or more non-radial transmission lines at 200 kV or above and four or more non-radial transmission lines between 100 kV and 200 kV, synchrophasor measurement signals will be required for the following equipment locations:

- Bus voltages at 100 kV and above
- Line-terminal voltage and current values for transmission lines at 100 kV and above
- High-side/low-side voltage and current values for transformers at 100 kV and above
- Dynamic reactive device power output (SVC, STATCOM, Synchronous Condenser, etc.)

PJM has committed to periodically evaluate the effectiveness of this new placement requirement, and will work with PJM stakeholders to modify such requirements as necessary.

The requirements will apply to new baseline and supplemental projects presented to the Transmission Expansion Advisory Committee (TEAC) and/or the Subregional RTEP Committees (SRRTEP) to be included in the RTEP after June 1, 2021.

Enhanced Planning Models

Model validation is a key and novel application of PMU-driven data. System Planning, Operations and Market Services rely heavily on power flow and other simulation models, investing significant time and resources to ensure that they accurately depict the physical behavior of the system. In particular, PMU technology allows PJM to recognize, detect and mitigate electromechanical oscillations, which helps system operators quickly identify potential instability before it has a chance to spread and interrupt service. Overall, further penetration of PMUs promises to revolutionize the practice of evaluating the status of the transmission system, making the process faster and the system more resilient.

1.3.8 — Resilience

As the grid of the future continues to develop, PJM must ensure that it does so on a solid foundation of reliability, one that integrates greater resilience into the existing reliability standards by which PJM plans and operates the grid. To that end, PJM continues to contend with a range of emerging challenges, including extreme weather, cyber and physical attacks, changes in the electric generation fleet driven by cheap and plentiful natural gas, and increased deployment of renewable resources. The pace of those changes has pushed grid operators to prepare for future vulnerabilities for which no set of standards currently exist. To be resilient, PJM must prepare for, operate through and recover from threats, as depicted in **Figure 1.16**.

The Role of Transmission in Resilience

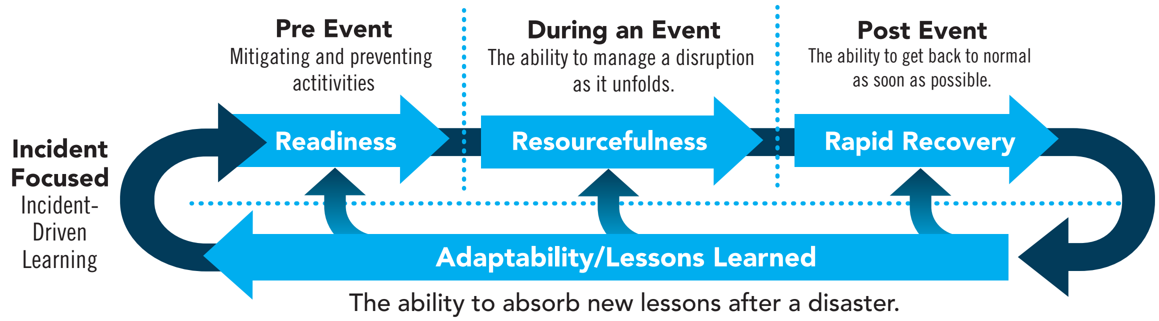
For decades, planning criteria has been developed and applied to power systems around the world to ascertain the need for new transmission. This provides a robust grid so that system operators can address various operating scenarios on any given day. Planners test the system under simulated stressed conditions – extreme weather conditions, for example – to understand where reinforcements are needed to make the grid reliable.

NERC planning criteria require that the bulk power system be tested for such contingencies as the loss of a transmission line – a high-probability, low-impact event – under the assumption that every other transmission facility is in service. Yet in reality, dozens of facilities are out of service on the system on any given day. PJM also simulates more severe, lower-probability events like multiple facility outages. These include the loss of two circuits on a common tower line or a fault on a circuit followed by a breaker failure or two unrelated contingencies, otherwise known as the N-1-1 test.

NERC standards address resilience to a degree. Planning standards also require examination of the impact of extreme events such as the loss of an entire substation or the loss of an entire right-of-way caused by a landslide, tornado or fire, taking down multiple transmission lines in one corridor. Although an assessment of the impact of these events is required, reinforcement for these low-probability events is not required under current NERC criteria.

Reliability criteria are structured around likely events. Planners must also assess whether the transmission system is sufficiently reinforced to address extreme events such as physical and cybersecurity attacks or extreme weather conditions like hurricanes.

Figure 1.16: Defining Resilience



Resilience: Taking Reliability a Step Further

Resilience and reliability both seek to keep the lights on but are not conceptually the same. PJM already complies with established NERC, regional and TO reliability standards. To that end, PJM conducts its planning studies under critical, stressed conditions so that system dispatchers can manage the actual system conditions on any given day in real time. Resilience takes this to another level, addressing challenges and emerging risks that existing reliability standards do not fully capture:

- Maintaining reliability in the face of significant events
- Evaluating threats as part of the RTEP process
- Slowing disruptive events, mitigating their impacts and quickly recovering essential functions
- Protecting essential systems based on assessed risks and hazards
- Improving grid flexibility and control to adapt efficiently and quickly to post-event conditions

PJM has initiated efforts to implement RTEP process criteria and metrics to enhance grid resilience beyond that in place today, as discussed in **Section 1.4.1**.

Cascading Event Analysis Tool Development

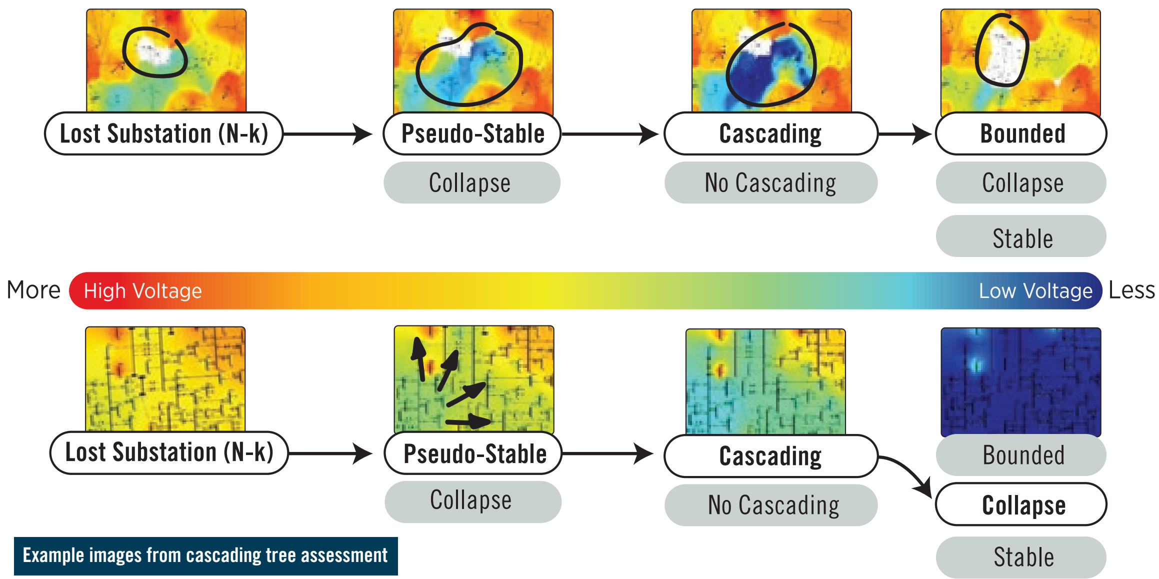
At its most fundamental, a cascading tree evaluates an extreme event that encompasses a risk that may, after some number of additional cascading events, lead to system collapse (i.e., blackout). Major blackouts are usually caused by low-probability, high-consequence events. Since the attacks on the Metcalf substation, the power industry has taken a closer look at system contingencies not only driven by naturally occurring events but additional man-made threats as well.

Any such initial precipitating event could cause one or more transmission line overloads (on common right-of-way), transformer overload, loss of substation, generator under-voltage, or load under-voltage conditions, among others. The high-voltage transmission network that crisscrosses the country was planned based on a set of reliability and efficiency criteria. These criteria generally ensure that the transmission system is capable of withstanding a significant outage to one, or a few, critical pieces of equipment. However, these planning criteria do not assess what would happen to the system should a significant disruption of many pieces of equipment occur at once, or in quick succession, as might be triggered by an extreme weather event or a deliberate attack.

Implementing Cascading Trees

PJM has begun developing such an assessment, called "cascading trees," shown conceptually in **Figure 1.17**. The purpose of this new methodology is to assess the probability and consequence of cascading outages in electric systems. A cascading tree is the set of all likely cascading paths. These, in turn, describe a sequence of potential cascading outages that could reasonably be expected.

Figure 1.17: Cascading Tree Concept



These possible outages are then classified as shown in **Figure 1.17** based on whether the propagation of a disturbance can be confined to a certain area, or if the exact extent of the cascading cannot be determined. The initial event equates to the complete loss of a facility. Cascading trees quantify the probability of cascading and the extent of associated consequence, leading to a natural ranking of facilities. Facilities then can be grouped into different tiers, each having a different priority and a discrete set of mitigation actions.

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1.4: RTEP Process Milestones

1.4.1 — 2020 Activities

PJM's RTEP process is continually evolving as the scope of system enhancement drivers it addresses evolves. In addition to the efforts undertaken by PJM to bring the grid of the future into clearer focus, discussed in **Section 1.3**, several milestones were achieved throughout 2020 as PJM continued to implement process improvements, as discussed below.

1.4.2 — Load Forecast Update/Accuracy

PJM annually reviews the load forecast methodology and implements changes when improvements are identified. For the 2021 load forecast, the major changes encompassed refinements to sector models and non-weather-sensitive load, both of which were first introduced with the 2020 load forecast. With respect to sector models, the commercial component of the load model was improved with the addition of service sector employment to more accurately reflect evolving economic conditions. Improvements to non-weather-sensitive models were also made to better align with underlying drivers and historical trends, reducing expected load impacts.

Each year, PJM measures the accuracy of the long-term load forecast model by running it with up-to-date inputs, solving with actual weather and comparing to actual load. This measure of accuracy is meant to show how well the model would have performed with the most recent forecast inputs. PJM reviews model accuracy results on the 10 highest coincident peak days for each season, for a number of forecast horizons with the Load Analysis Subcommittee.

PJM's most recent report on model accuracy is available on the PJM website.

1.4.3 — Storage as Transmission Asset

Building on work PJM performed in previous years, in 2020, PJM initiated an effort to determine how energy storage could be treated as a transmission asset and integrated into the RTEP process to enhance grid reliability. Storage as a transmission asset (SATA) was evaluated by PJM and its stakeholders for suitability as a transmission system enhancement. PJM also reviewed existing rules in PJM governing documents and identified gaps that would affect the integration of SATA into the RTEP.

PJM recognizes the unique characteristics of SATA, which could position it as a potentially more cost effective, efficient grid solution alternative to building new power lines in certain circumstances. PJM is also keenly aware of the complexity that SATA will bring to operations and markets functions. For this reason, PJM chose to study SATA in phases, over multiple years. The Phase 1 scope is to consider SATA solely as a transmission asset, and the ability to address drivers for reliability, market efficiency, operational performance and public policy. With stakeholder input, PJM proposed a package of recommendations for evaluating SATA as part of the RTEP process. These recommendations allow for transparency in studying SATA for suitability in mitigating reliability criteria violations and market efficiency constraints, as well as project cost analysis so SATA can be directly compared to traditional wires solutions.

The Phase 1 work is only the first step in evaluating SATA as part of the RTEP. PJM is committed to work with stakeholders to discuss the feasibility for SATA to have dual-use privileges as a transmission asset when needed for reliability reinforcement, and as a market participant at other times along with associated markets and operations issues.

1.4.4 — Critical Infrastructure Stakeholder Oversight

NERC CIP-014 Standard

The NERC CIP-014 standard requires TO assessments to identify critical facilities that, if rendered inoperable, would cause instability, uncontrolled separation or cascading outages. Concerns across the industry about grid security and resilience continue to grow. Throughout 2020, PJM continued to pursue opportunities to embed testing and other strategies in its RTEP process to ensure those concerns are addressed. Specifically, PJM continues to support efforts to eliminate current vulnerabilities for CIP-014 critical infrastructure, while also working to develop RTEP process criteria to avoid and mitigate the risk of potential future CIP-014 critical infrastructures facilities.

Attachment M4 Process

On March 17, 2020, FERC approved Attachment M4 of the PJM Tariff, which will govern the planning of CIP-014 Mitigation Projects (CMPs). These CMP projects are designed to address existing identified CIP-014 facilities, and are limited, based on the filing, to only those facilities which were identified as of Sept. 30, 2018. The locations of these facilities are confidential, but has been publicly identified as not to exceed 20.

Avoidance and Mitigation

Through the Consensus Based Issues Resolution (CBIR) process, stakeholders evaluated and developed a process by which to: (1) Avoid the addition of new critical facilities to the PJM system by evaluating all model updates to minimize the possibility of a new critical facility; and (2) Mitigate the result of any new critical facility identified in PJM's footprint.

Stakeholder review of these concepts and corresponding updates to documentation are following the established PJM committee approval process and are expected to be voted on at the Markets and Reliability Committee in the second quarter of 2021.

1.4.5 — Market Efficiency Process Enhancement Task Force

The Market Efficiency Process Enhancement Task Force (MEPETF) was chartered in January 2018, under the auspices of the PJM Planning Committee. The mission of this group is to review, evaluate and discuss challenges and potential solutions necessary to improve the market efficiency process. The scope of MEPETF activities includes the following:

- Provide educational material
- Evaluate benefit-to-cost calculation
- Evaluate facility study agreement modeling
- Evaluate the market efficiency reevaluation process and mid-cycle assumption update
- Select interregional market efficiency project
- Evaluate regional targeted market efficiency process
- Update market efficiency midcycle assumption and model

Process reviews were conducted in three phases. In April 2019, the MEPETF started work on Phase 3, which entailed investigating a new Regional Targeted Market Efficiency Project process and looking into the separation of energy and capacity benefits in the benefit-to-cost calculations. Phase 3 was completed upon FERC's Dec. 18, 2020, acceptance of PJM's proposed Operating Agreement revisions. Additional discussion on the MEPETF activities, including those that continued throughout 2020, are included in **Section 4.4.**

NOTE:

PJM received endorsement of requisite Manuals 14B and 14F language by the Planning Committee in February 2021. Pending approval of the Markets and Reliability Committee, those manual changes along with additional changes to Schedule 6 of PJM's Operating Agreement will become effective upon FERC acceptance of PJM's anticipated Operating Agreement Critical Infrastructure Stakeholder Oversight filing.

Section 2: Resource Adequacy Modeling

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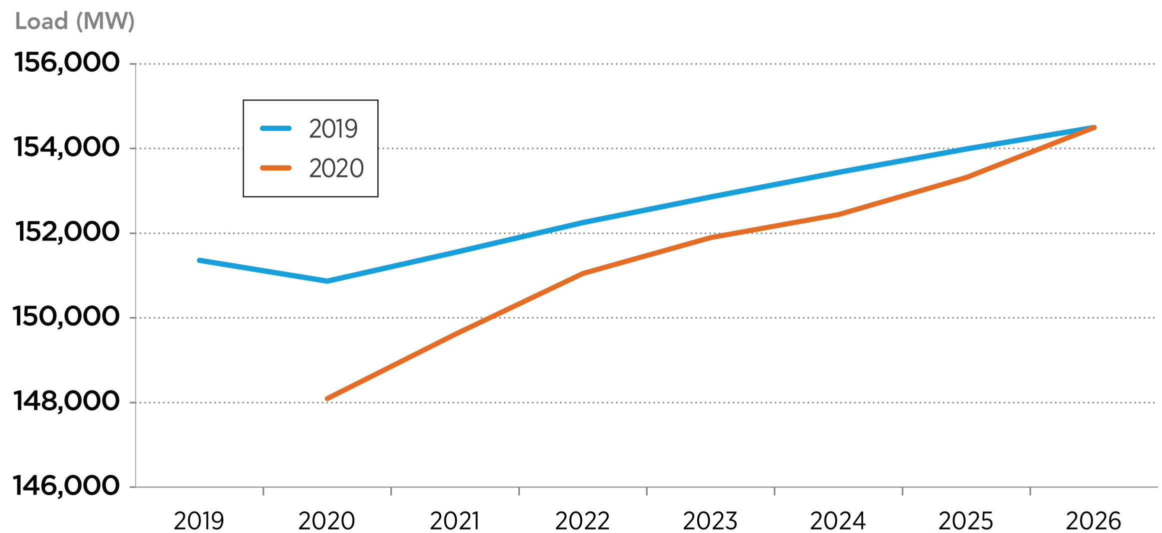
2.0: Power Flow Model Load

Fundamentally, PJM's planning process identifies future system transmission needs based on power flow studies that reveal reliability criteria violations. Power flow study models incorporate the effect of many system expansion drivers. Zonal load forecasts are the basis for power flow case bus loads. Modeling load this way is essential if transmission expansion studies are to yield plans that will continue to ensure reliable and economically efficient system operations.

As a starting point, in order to develop a power flow basecase model, PJM assigns zonal load from its January forecast to individual zonal buses according to ratios of each bus load to total zonal load. Ratios are supplied by each transmission owner. Given that loads in different geographical areas peak at different times, for load deliverability studies, zonal load is studied at its non-coincident level (i.e., at the time of the zone's peak).

Figure 2.1: Summer Peak Load Forecast 2020 vs. 2019



2020 RTEP Process Context

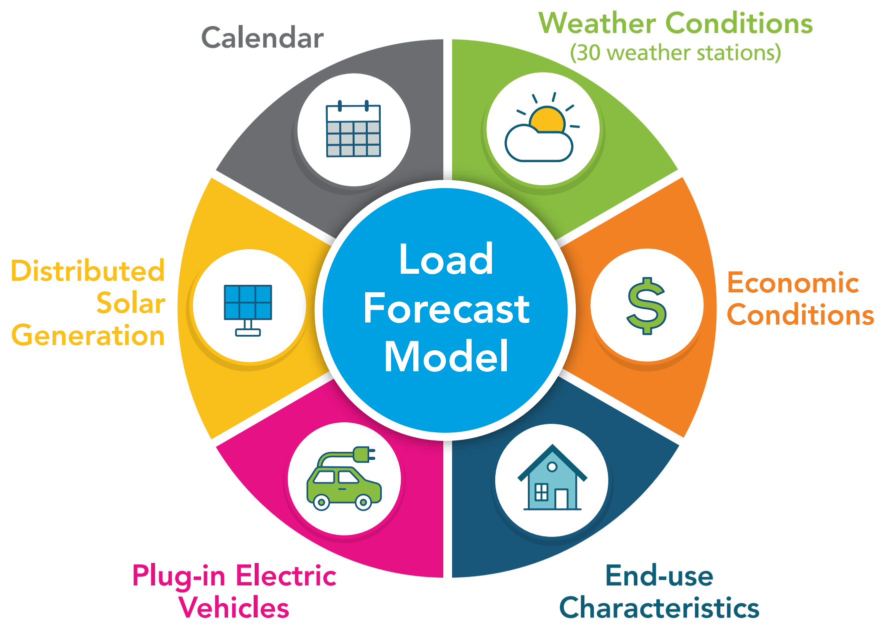
PJM's 2020 RTEP baseline power flow model for study year 2025 is based on the 2020 PJM Load Forecast Report. Summarized in the sections that follow, PJM's January 2020 load forecast covered the 2020 through 2035 planning horizon. From a power flow modeling perspective, the 2025 summer peak from that January 2020 forecast at an overall RTO demand of 153,315 MW was the basis for developing PJM's 2025 basecase power flow model. Doing so will reflect that PJM now projects its RTO summer-normalized peak to grow 0.6 percent annually over the next 10 years, shown in **Figure 2.1**, which is up 0.3 percentage points from the 2019 forecast.

Load Forecasting Process

PJM's load forecast model produces a 15-year forecast for each PJM zone, Locational Deliverability Area, and the RTO. The model estimates the historical relationship between load (peak and energy) and a range of different drivers, including weather variables, economics, calendar effects, end-use characteristics (equipment/appliance saturation and efficiency), distributed solar generation, and plug-in electric vehicles. And it leverages those relationships to derive forecasted load, shown in **Figure 2.2**

PJM instituted several significant changes starting with the 2020 load forecast, aimed at providing a more accurate forecast that better aligns with ongoing load trends. For the 2020 load forecast, PJM introduced sector models and used the concept of non-weather-sensitive load. These changes were implemented through significant stakeholder engagement at the Load Analysis Subcommittee and Planning Committee meetings.

Figure 2.2: Load Forecast Model



Calibration

The new model takes advantage of publicly available sector data to calibrate the independent variables used to forecast load, such as end-use and economic trends. Load data used in the PJM load forecast is at the transmission zone level, but unseen are the customers that contribute to that load. These customers broadly come from three sectors: residential, commercial and industrial. Understanding trends in each of these categories is valuable to understanding the whole picture. PJM leverages data from the Energy Information Administration's (EIA) Form 861, the Annual Electric Power Industry Report, in order to better inform this understanding.

Distributed Solar Generation

PJM is taking a more granular approach to modeling behind-the-meter solar load forecast impacts. The solar output by weather scenario varies in the same way that the weather related to the historical weather scenario in the weather simulation varies. Distributed solar generation acts to lower load from what it otherwise would be. Recent years have witnessed a significant ramp-up in behind-the-meter distributed solar resources.

Plug-In Electric Vehicles

For the first time, PJM is incorporating an explicit adjustment for plug-in electric vehicle (PEV) charging in its peak and energy forecasts. PJM wants to be sure to account for PEVs to maintain reliability, as the share of plug-in electric vehicles on the road continues to grow.

Weather Conditions

Weather conditions across the RTO are accounted for by calculating a load-weighted average of temperature, humidity, wind speed and cooling degree days. PJM obtains weather data from over 30 identified weather stations across the PJM region.

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Calendar
Calendar effects are variables that represent the day of the week, month and holidays.

Economic Conditions
The economic dimension used in the calibration includes economic measures of households, real personal income, population, working age population and goods-producing output. This allows for localized treatment of economic effects within a zone. PJM has contracted with an outside economic services vendor to provide economic forecasts for all areas within the PJM footprint.

End-Use Characteristics
End-use characteristics are captured through three distinct variables designed to capture the various ways in which electricity is used: both weather-sensitive heating and cooling and non-weather-sensitive use. Each variable addresses a collection of different equipment types, accounting over time for both the saturation of that equipment type, as well as its respective efficiency. For instance, the cooling variable captures increasing central air conditioning unit efficiency.

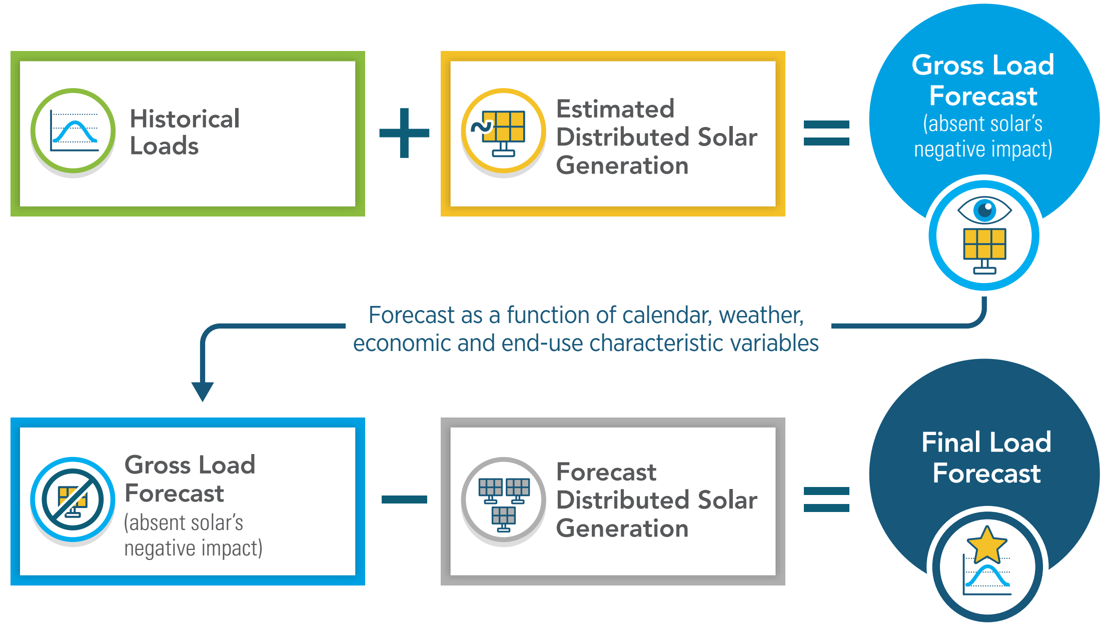
PJM has updated its load forecast model in a way that reflects the continued evolution toward a more service-driven, less manufacturing-based, less energy-intensive economy. A trend that is further driven by the accelerated proliferation of energy-efficient electric appliances and equipment.

Distributed Solar Generation
Recent years have witnessed a significant ramp-up in behind-the-meter distributed solar resources: more than 4,500 MW since 1998, with more than 95 percent of installations since 2010. Though not a large amount from an RTO perspective, the level of distributed solar is significant in certain areas of PJM and is expected to increase more in the years ahead. Under PJM's model update, distributed solar generation impacts are reflected in its load forecast using the approach shown in **Figure 2.3** to determine a final load forecast.

PJM first adds back estimated distributed solar generation to its historical loads to obtain a hypothetical history of loads as if solar did not exist. PJM uses a vendor-supplied historical estimate of hourly distributed solar generation, based on the installation date and location of resources.

Having obtained a load forecast as if solar did not exist, PJM then subtracts existing and forecasted distributed solar generation to obtain a final load forecast for each zone and for the RTO. Forecasted distributed solar generation is based on vendor-supplied, forecasted distributed solar capacity additions over the ensuing 15 years. The vendor forecast takes into consideration assumptions for federal and state policy, net energy metering policy, energy growth, solar photovoltaic capital costs, power prices and other factors. This forecast is discounted for: (1) expected panel degradation over time; (2) solar energy production that does not align with the timing of PJM's peak load.

Figure 2.3: Accounting for Distributed Solar Generation



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2.1: January 2020 Forecast

PJM's January 2020 load forecast used in 2020 RTEP studies covered the 2020 through 2035 planning horizon, highlights of which are summarized in this section. The complete January 2020 PJM Load Forecast Report is accessible on the PJM website. As that report states, PJM's 2025 RTO summer peak is forecasted to be 153,315 MW.

Forecasting Trends

Table 2.1 summarizes the seasonal transmission owner zonal summer and winter 10-year forecasts and load growth rates for 2020 through 2030. All load forecasts in the table reflect adjustment for distributed solar generation and plug-in electric vehicles. Adjustments to the summer, 10-year forecast are summarized in **Table 2.2**. Adjustments to the winter forecast for distributed solar are approximately zero.

Table 2.3 compares 10-year load growth rates for each PJM transmission owner zone and for the overall RTO over the past five years. Lower load forecast trends over that period reflect broader trends in the U.S. economy and PJM model refinements to capture energy efficiency. These trends are subsequently reflected in RTEP process power flow models.

Table 2.1: 2020 Load Forecast Report

	Summer Peak (MW)			Winter Peak (MW)		
Transmission Owner	2020	2030	Growth Rate	2019/20	2029/30	Growth Rate
Atlantic City Electric Co.	2,542	2,773	0.9%	1,543	1,715	1.1%
Baltimore Gas and Electric Co.	6,447	6,558	0.2%	5,859	6,290	0.7%
Delmarva Power & Light Co.	3,979	4,327	0.8%	3,729	4,124	1.0%
Jersey Central Power & Light	5,842	6,122	0.5%	3,669	4,013	0.9%
Met-Ed	3,003	3,287	0.9%	2,686	2,893	0.7%
PECO Energy Co.	8,415	8,677	0.3%	6,792	6,727	-0.1%
Pennsylvania Electric Co.	2,849	2,957	0.4%	2,824	2,816	-0.0%
PPL Electric Utilities Corp.	7,069	7,792	1.0%	7,336	7,772	0.6%
Potomac Electric Power Co.	6,109	5,794	-0.5%	5,699	5,845	0.3%
PSEG	9,792	10,597	0.8%	6,686	7,341	0.9%
Rockland Electric Co.	395	420	0.6%	216	241	1.1%
UGI Utilities	191	184	-0.4%	200	187	-0.7%
Diversity – Mid-Atlantic	-781	-948		-557	-644	
Mid-Atlantic	**55,852**	**58,540**	**0.5%**	**46,682**	**49,320**	**0.6%**
American Electric Power Co.	21,945	24,113	0.9%	22,000	23,544	0.7%
Allegheny Power	8,685	9,373	0.8%	8,851	9,498	0.7%
American Transmission Systems, Inc.	12,378	12,428	0.0%	10,349	10,240	-0.1%
Commonwealth Edison Co.	20,635	20,876	0.1%	14,400	14,621	0.2%
Dayton Power & Light Co.	3,236	3,228	-0.0%	2,909	2,813	-0.3%
Duke Energy Ohio and Kentucky	5,280	5,650	0.7%	4,550	4,894	0.7%
Duquesne Light Co.	2,759	2,855	0.3%	2,070	2,113	0.2%
East Kentucky Power Cooperative	2,004	2,334	1.5%	2,701	3,094	1.4%
Ohio Valley Electric Corp.	95	95	0.0%	125	125	0.0%
Diversity – Western	-1,377	-1,311		-1,403	-1,381	
Western	**75,640**	**79,641**	**0.5%**	**66,552**	**69,561**	**0.4%**
Dominion Virginia Power	19,813	22,336	1.2%	20,382	23,531	1.4%
Southern	**19,813**	**22,336**	**1.2%**	**20,382**	**23,531**	**1.4%**
Diversity – Total	-5,371	-5,644		-4,289	-4,467	
PJM RTO	**148,092**	**157,132**	**0.6%**	**131,287**	**139,970**	**0.6%**

Table 2.2: Distributed Solar Generation and PEV Adjusted to Summer Peak

	Adjustment to Summer Peak (MW)			
	Distributed Solar Generation		Plug In Electric Vehicle	
Transmission Owner	2020	2030	2020	2030
Atlantic City Electric Co.	200	263	5	36
Baltimore Gas and Electric Co.	205	562	12	82
Delmarva Power & Light Co.	117	259	5	32
Jersey Central Power & Light	296	459	12	86
Met-Ed	29	57	3	21
PECO Energy Co.	44	106	8	62
Pennsylvania Electric Co.	9	40	3	20
PPL Electric Utilities Corp.	71	132	7	50
Potomac Electric Power Co.	167	525	10	73
PSEG	436	773	20	144
Rockland Electric Co.	9	22	1	6
UGI Utilities	0	2	0	1
American Electric Power Co.	49	397	15	115
Allegheny Power	81	267	7	52
American Transmission Systems, Inc.	55	364	10	72
Commonwealth Edison Co.	101	468	27	201
Dayton Power & Light Co.	12	104	2	19
Duke Energy Ohio and Kentucky	16	173	4	28
Duquesne Light Co.	12	31	3	20
East Kentucky Power Cooperative	5	10	1	7
Ohio Valley Electric Corp.	0	0	0	0
Dominion Virginia Power	406	820	17	121
PJM RTO	**1,963**	**5,445**	**172**	**1,248**

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Table 2.3: Comparison of 10-Year Summer Peak Load Growth Rates

	Load Forecast Report Summer Peak (MW)														
	2016			2017			2018			2019			2020		
Transmission Owner	2016	2026	Growth Rate	2017	2027	Growth Rate	2018	2028	Growth Rate	2019	2029	Growth Rate	2020	2030	Growth Rate
Atlantic City Electric Co.	2,524	2,502	-0.1%	2,495	2,445	-0.2%	2,460	2,409	-0.2%	2,450	2,388	-0.3%	2,542	2,773	0.9%
Baltimore Gas and Electric Co.	6,945	7,220	0.4%	6,889	6,911	0.0%	6,848	6,744	-0.2%	6,697	6,663	-0.1%	6,447	6,558	0.2%
Delmarva Power & Light Co.	3,991	4,135	0.4%	4,028	3,983	-0.1%	3,937	4,018	0.2%	3,933	3,962	0.1%	3,979	4,327	0.8%
Jersey Central Power & Light	5,968	6,156	0.3%	6,056	6,108	0.1%	5,942	5,943	0.0%	5,914	5,912	0.0%	5,842	6,122	0.5%
Met-Ed	2,940	3,176	0.8%	2,940	3,028	0.3%	2,974	3,115	0.5%	2,986	3,157	0.6%	3,003	3,287	0.9%
PECO Energy Co.	8,547	9,122	0.7%	8,547	8,693	0.2%	8,642	8,979	0.4%	8,711	9,082	0.4%	8,415	8,677	0.3%
Pennsylvania Electric Co.	2,890	2,919	0.1%	2,891	2,847	-0.2%	2,895	2,922	0.1%	2,897	2,908	0.0%	2,849	2,957	0.4%
PPL Electric Utilities Corp.	7,193	7,560	0.5%	7,132	7,186	0.1%	7,140	7,350	0.3%	7,148	7,347	0.3%	7,069	7,792	1.0%
Potomac Electric Power Co.	6,563	6,813	0.4%	6,614	6,543	-0.1%	6,493	6,466	0.0%	6,466	6,413	-0.1%	6,109	5,794	-0.5%
PSEG	10,090	10,222	0.1%	10,057	10,012	0.0%	9,903	9,876	0.0%	9,904	9,753	-0.2%	9,792	10,597	0.8%
Rockland Electric Co.	407	410	0.1%	404	404	0.0%	402	402	0.0%	404	402	0.0%	395	420	0.6%
UGI Utilities	188	190	0.1%	191	185	-0.3%	190	188	-0.1%	189	188	-0.1%	191	184	-0.4%
Diversity – Mid-Atlantic	-1,072	-872		-1,080	-1,161		-1,225	-1,086		-1,213	-1,135	0.0%	-781	-948	
Mid-Atlantic	**57,174**	**59,553**	**0.4%**	**57,164**	**57,184**	**0.0%**	**56,601**	**57,326**	**0.1%**	**56,486**	**57,040**	**0.1%**	**55,852**	**58,540**	**0.5%**
American Electric Power Co.	23,006	24,891	0.8%	22,945	23,888	0.4%	22,876	24,018	0.5%	22,945	24,072	0.5%	21,945	24,113	0.9%
Allegheny Power	8,817	9,554	0.8%	8,802	9,087	0.3%	8,825	9,447	0.7%	8,707	9,305	0.7%	8,685	9,373	0.8%
American Transmission Systems, Inc.	12,921	13,413	0.4%	12,994	13,177	0.1%	12,952	13,309	0.3%	12,872	13,134	0.2%	12,378	12,428	0.0%
Commonwealth Edison Co.	22,001	23,633	0.7%	22,296	22,872	0.3%	22,121	23,207	0.5%	21,890	22,514	0.3%	20,635	20,876	0.1%
Dayton Power & Light Co.	3,403	3,647	0.7%	3,479	3,503	0.1%	3,459	3,508	0.1%	3,408	3,525	0.3%	3,236	3,228	0.0%
Duke Energy Ohio and Kentucky	5,436	5,853	0.7%	5,497	5,741	0.4%	5,523	5,860	0.6%	5,480	5,742	0.5%	5,280	5,650	0.7%
Duquesne Light Co.	2,893	2,985	0.3%	2,884	2,882	0.0%	2,872	2,924	0.2%	2,862	2,887	0.1%	2,759	2,855	0.3%
East Kentucky Power Cooperative	1,924	2,041	0.6%	1,948	2,010	0.3%	1,960	2,033	0.4%	1,989	2,072	0.4%	2,004	2,334	1.5%
Ohio Valley Electric Corp.										95	95	0.0%	95	95	0.0%
Diversity – Western	-1,572	-1,574		-1,529	-1,468		-1,540	-1,522		-1,612	-1,369		-1,377	-1,311	
Western	**78,829**	**84,443**	**0.7%**	**79,316**	**81,692**	**0.3%**	**79,048**	**82,784**	**0.5%**	**78,636**	**81,977**	**0.4%**	**75,640**	**79,641**	**0.5%**
Dominion Virginia Power	19,531	22,041	1.2%	19,729	20,501	0.4%	19,596	21,161	0.8%	19,391	21,238	0.9%	19,813	22,336	1.2%
Southern	**19,531**	**22,041**	**1.2%**	**19,729**	**20,501**	**0.4%**	**19,596**	**21,161**	**0.8%**	**19,391**	**21,238**	**0.9%**	**19,813**	**22,336**	**1.2%**
Diversity – RTO	-3,403	-4,146		-3,210	-3,604		-3,137	-3,636		-5,980	-6,070		-5,371	-5,644	
PJM RTO	**152,131**	**161,891**	**0.6%**	**152,999**	**155,773**	**0.2%**	**152,108**	**157,635**	**0.4%**	**151,358**	**156,689**	**0.3%**	**148,092**	**157,132**	**0.6%**

2020 Forecast Summer Zonal Load Growth Rates

The PJM RTO weather-normalized summer peak is forecasted to grow at an average rate of 0.6 percent per year for the next 10 years. The PJM RTO summer peak is forecasted to be 157,132 MW in 2030, an increase of 9,040 MW over the 2020 peak of 148,092 MW. Individual geographic zone growth rates vary from -0.5 percent to 1.5 percent, as shown in **Figure 2.4** and **Figure 2.5**.

Figure 2.4: PJM Mid-Atlantic Summer Peak Load Growth 2020-2030

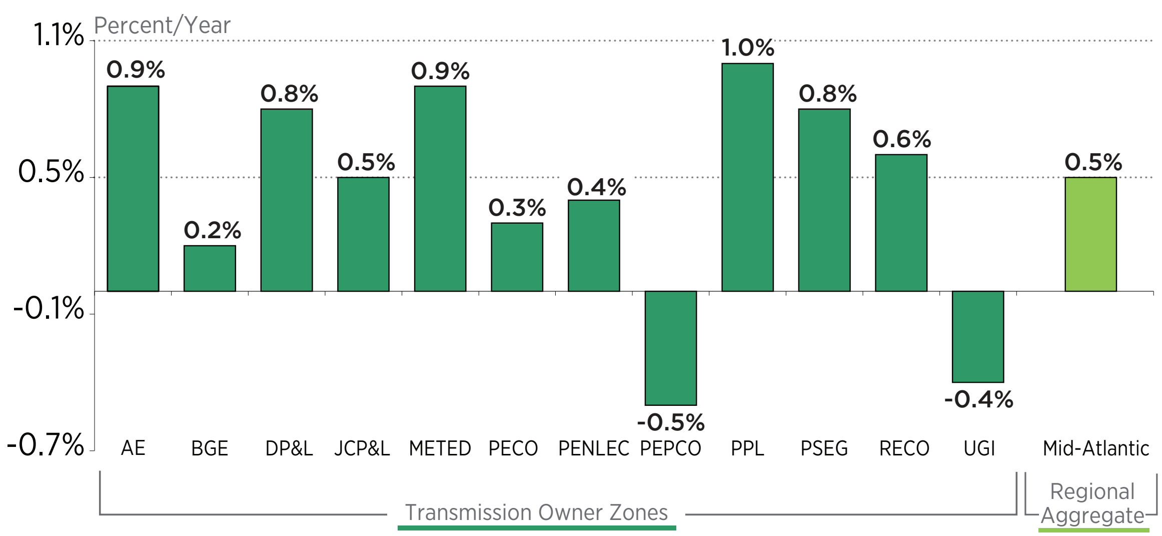
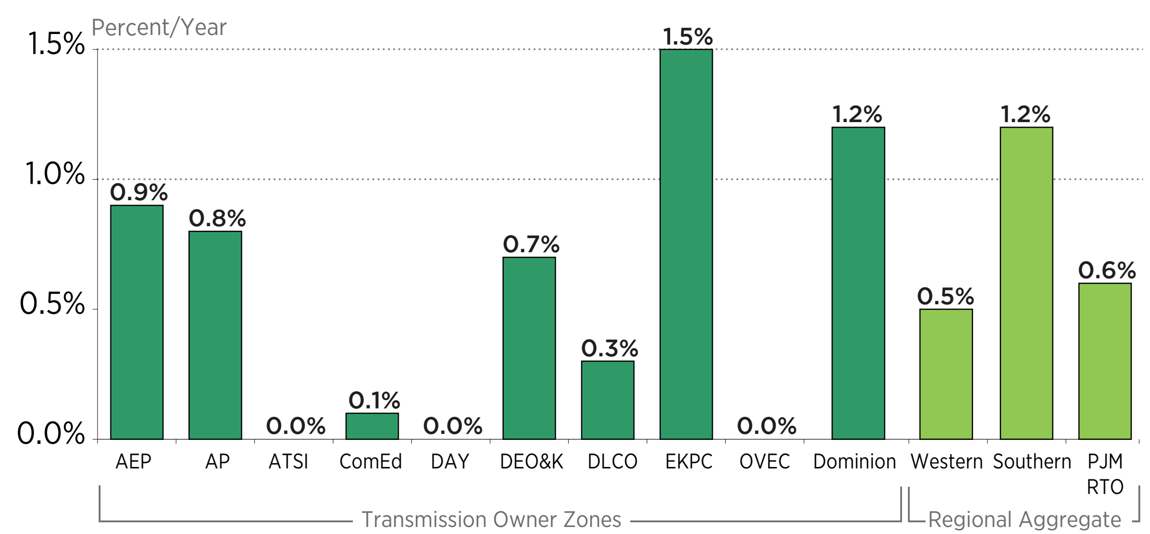


Figure 2.5: PJM Western and Southern Summer Peak Load Growth 2020-2030



2020 Forecast Winter Zonal Load Growth Rates

The PJM RTO weather-normalized winter peak is forecasted to grow at an average rate of 0.6 percent per year for the next 10 years. The PJM RTO winter peak is forecasted to be 139,970 MW in 2029/2030, an increase of 8,683 MW over the 2019/2020 peak of 131,287 MW. Individual geographic zone growth rates vary from -0.7 percent to 1.4 percent, as shown in **Figure 2.6** and **Figure 2.7**.

Figure 2.6: PJM Mid-Atlantic Winter Peak Load Growth 2020-2030

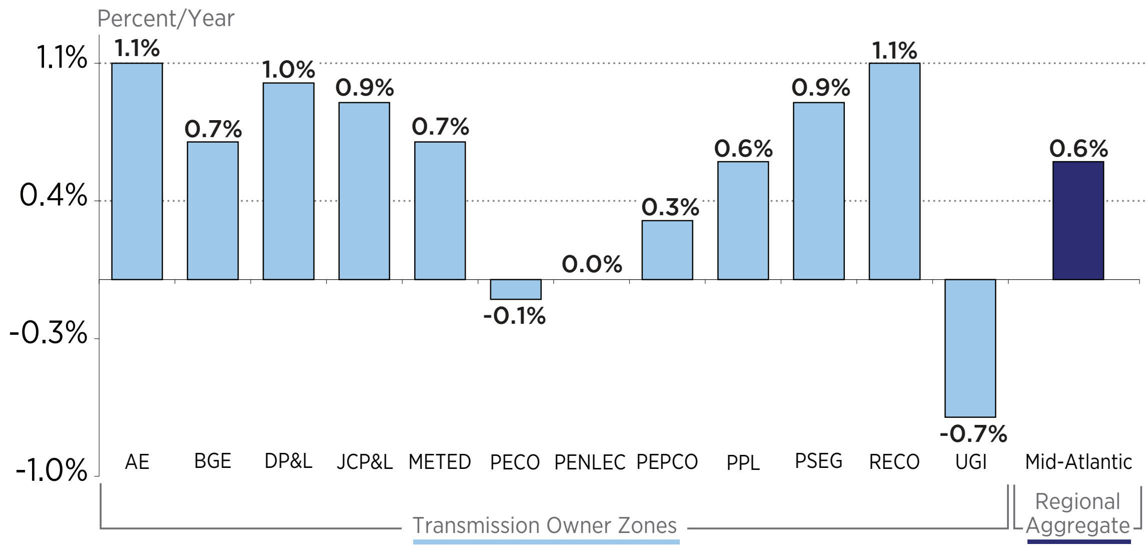
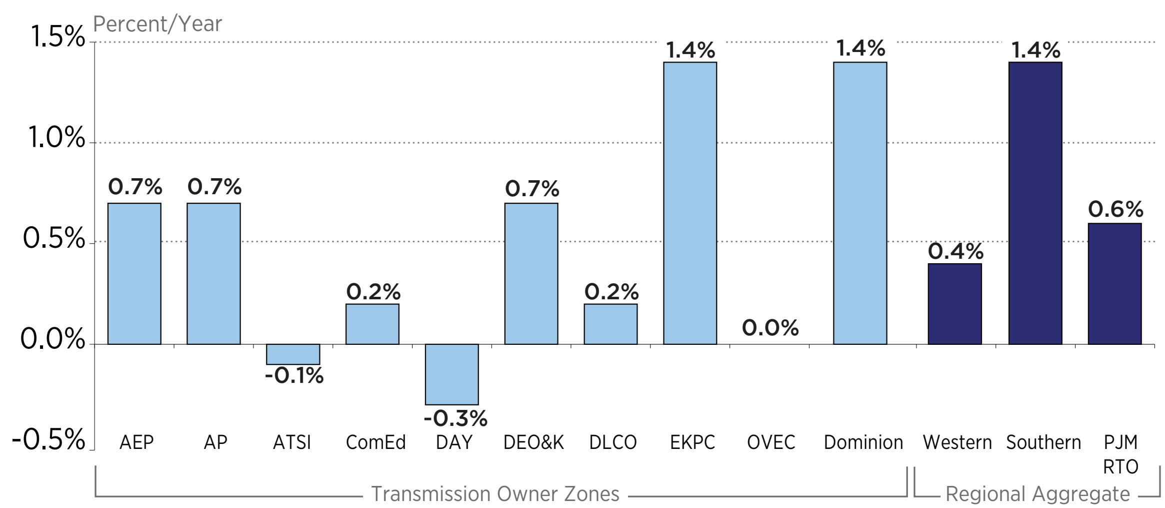


Figure 2.7: PJM Western and Southern Winter Peak Load Growth 2020-2030



Subregional Forecast Trends

Figure 2.8 provides a summary based on load growth rate trends from the respective January load forecast over each of the last five years, from 2016 through 2020, for the ensuing 10 years on a subregional basis. The trend reflects changes in the broader U.S. economic outlook and the growing impact of energy efficiency, solar and plug-in electric vehicles looking forward in each of the five forecasts.

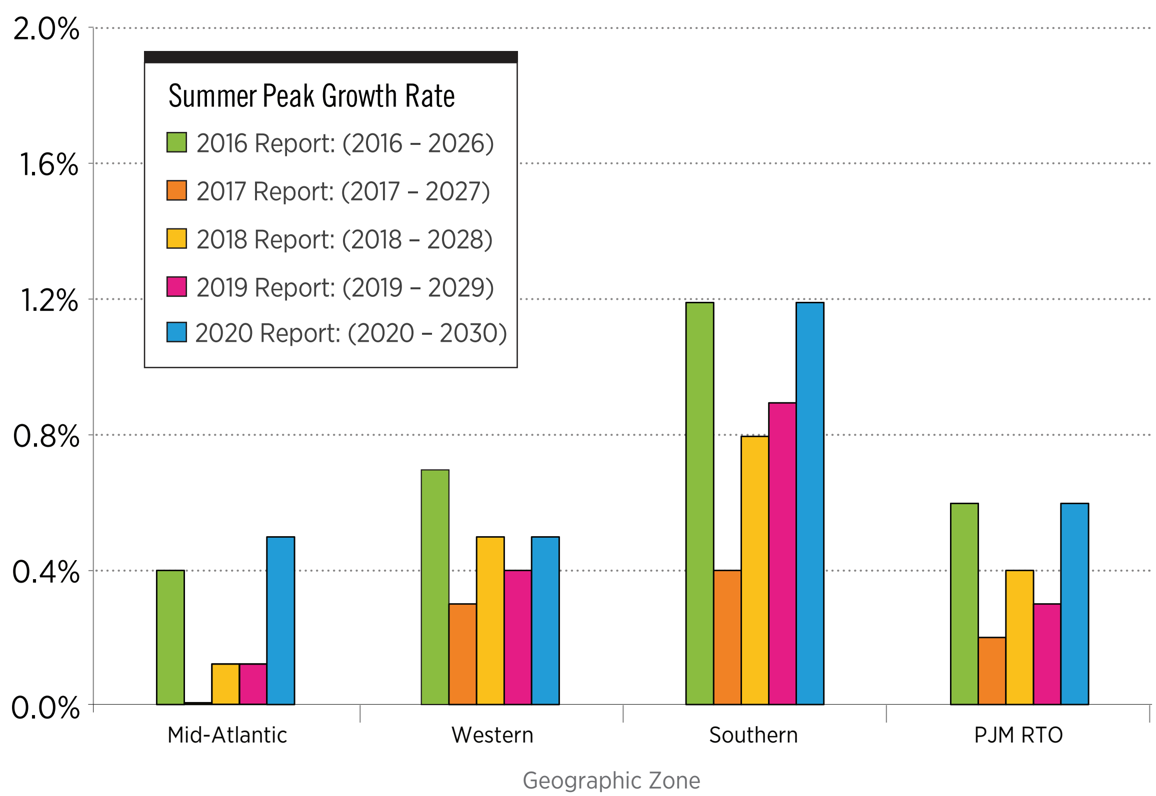
In particular, the 2020 report forecasted that load growth rate for the RTO increased by 0.3 percentage points when compared to the 2019 report.

2.1.1 — Effective Load Carrying Capability

As the resource mix in PJM evolves to include more renewables – such as wind and solar, as well as other emerging technologies, such as energy storage, offshore wind and hybrid resources (generation combined with energy storage) – the way in which PJM evaluates the contribution of such resources toward resource adequacy also needs to evolve. This is required to account for the effect that increased penetration levels of these resources is likely to have on PJM's loss of load probability (LOLP) risk profile.

Recognizing this dynamic, in 2018 the Planning Committee began discussions on a new methodology for calculating the capacity capability of wind and solar. More recently, in 2020, as part of the proceedings surrounding PJM's compliance filing on FERC Order 841 (Energy Storage Resources), PJM responded to FERC that it was committed to investigating a new methodology for calculating the capacity capability of energy storage resources. PJM told FERC that it would start a stakeholder process to address this issue.

Figure 2.8: PJM 10-Year Summer Peak Load Growth Rate Comparison 2016-2020 Load Forecast Reports



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PJM then put forward a Problem/Opportunity Statement and Issue Charge, approved at the March 2020 Markets and Reliability Committee (MRC) meeting, which led to the creation of the Capacity Capability Senior Task Force (CCSTF). The CCSTF was tasked with the development of the provisions necessary to establish an effective load carrying capability (ELCC) method for calculating the capacity capability of certain resources. These will include energy storage resources and intermittent resources, such as wind, solar, hydroelectric power with and without storage reservoirs, and other renewable resources as well as hybrid resources.

ELCC is a well-established methodology based on LOLP calculations employed to estimate the reliability value/capacity capability of resources. At the CCSTF, PJM staff provided education on ELCC, LOLP and PJM Resource Adequacy studies. Also at the CCSTF, PJM and stakeholders developed and discussed multiple solution packages in response to the Problem/Opportunity Statement and Issue Charge. At the September 2020 MRC meeting, a sector-weighted majority of stakeholders voted in favor of one of the solution packages. Some key elements of this member-endorsed solution package include: (1) a simulated output dispatch approach for limited-duration, hybrid and hydro with storage resources; and (2) a transition plan that considers the concept of capacity capability floors for resources.

PJM filed Tariff and Reliability Assurance Agreement (RAA) changes with FERC on Oct. 30, 2020, based on the member-endorsed solution package. PJM is expecting to implement an ELCC in 2021, pending FERC approval.

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

2.2: Demand Resources and Peak Shaving

PJM accounts for demand resources by adjusting its base, unrestricted, peak load forecast by the amount that clears Reliability Pricing Model auctions. Those amounts, as reflected in the 2020 Load Forecast Report, are shown in **Table 2.4** for each transmission owner zone. The adjusted forecast is then used in RTEP power flow model studies that focus on summer peak capacity emergency conditions, during which demand resources are assumed to be implemented. Consequently, demand resources can have a measurable impact on future system conditions and potential need for transmission system enhancements to serve load. Forecasted values for each zone are determined based on the following steps:

1. Compute the final amount of committed demand resources for each of the three most recent delivery years. Express the committed demand resource amount as a percentage of the zone's 50/50 forecast summer peak from the January load forecast report immediately preceding the respective delivery year.
2. Compute the most recent three-year average committed demand resources percentage for each zone.
3. Multiply each zone's 50/50 forecast summer peak by the results from step two to obtain the demand resource forecast for each zone.

Alternatively, load management can directly impact the unrestricted peak load forecast through a peak shaving program. Peak shaving program administrators provide PJM with information on curtailment behavior (e.g., duration, trigger, curtailed-load hourly profile), which PJM then uses to inform the load forecast. No peak shaving programs are included in this year's forecast used for the RTEP.

Capacity Performance Impacts

PJM's RPM transition to Capacity Performance in 2016 has required a transition in the treatment of demand resources as well. **Table 2.4** assumes the following:

- *Delivery years 2020 and beyond:* Annual demand resources are assumed to become Capacity Performance demand resources and are based on actual cleared quantities of demand resource products in the 2020/2021 and 2021/2022 RPM Base Residual Auction.
- *Summer period demand resources:* Refers to demand resources that aggregate with winter-period resources to form a year-round commitment.

Both existing and planned demand resources may participate in auctions, provided the resource resides in a party's portfolio for the duration of the delivery year. Further details can be found in PJM Manual 19, Load Forecasting and Analysis, available on the PJM website.

Table 2.4: 2020 Load Forecast Report Demand Resources

	Total Load Management	
Transmission Owner	2020	2030
Atlantic City Electric Co.	70	77
Baltimore Gas and Electric Co.	560	510
Delmarva Power & Light	280	314
Jersey Central Power & Light	142	149
Met-Ed	278	305
PECO Energy Co.	363	374
Pennsylvania Electric Co.	303	315
PPL Electric Utilities Corp.	577	634
Potomac Electric Power Co.	413	394
PSEG	336	363
Rockland Electric Co.	4	5
UGI Utilities	0	0
Mid-Atlantic	**3,326**	**3,440**
American Electric Power Co.	1,174	1,290
Allegheny Power	758	818
American Transmission Systems, Inc.	801	804
Commonwealth Edison Co.	1,492	1,509
Dayton Power & Light	169	168
Duke Energy Ohio and Kentucky	160	171
Duquesne Light Co.	130	134
East Kentucky Power Cooperative	138	161
Ohio Valley Electric Corp.	0	0
Western	**4,822**	**5,055**
Dominion Virginia Power	781	880
Southern	**781**	**880**
PJM RTO	**8,929**	**9,375**

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

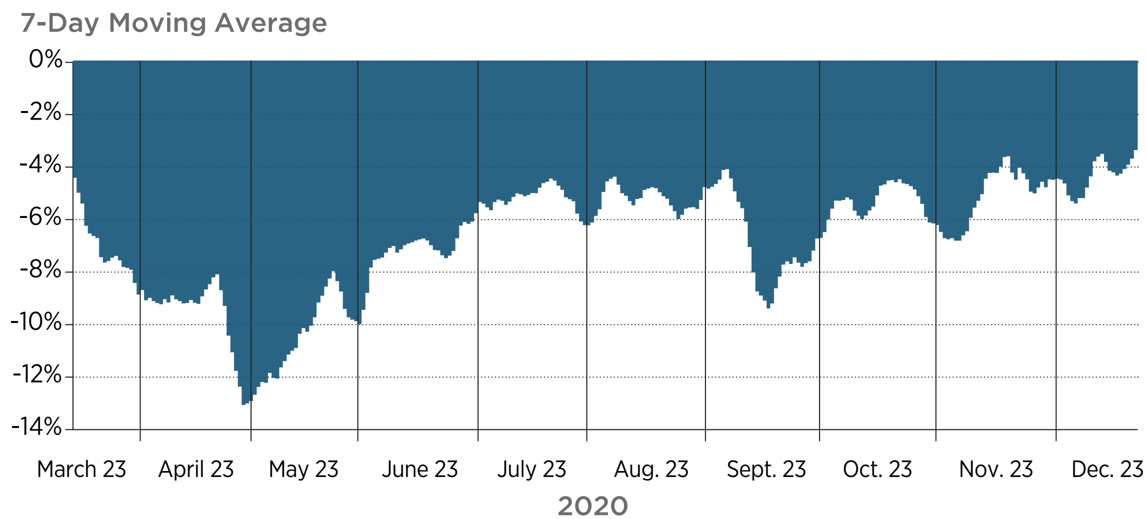
2.3: Load Forecast – COVID-19 Impacts

PJM used the 2020 load forecast to estimate impacts on peaks during the COVID-19 pandemic. The load model is solved with actual daily weather from 2020 and the results are compared to the observed load. The percent difference between these two numbers can be viewed as an estimate of the impact of COVID-19. A rolling 7-day average of these estimated impacts is shown In **Figure 2.9**.

In late March 2020, many states issued stay-at-home orders. This development, along with the broader economic turmoil, weighed heavily on commercial and industrial energy demand, but also shifted a greater proportion of electricity usage to residential customers. In the spring, when weather is generally mild, this resulted in demand impacts greater than 10% at times. As spring turned to summer and subsequently to fall, impacts ebbed and flowed. A consequence of a greater proportion of load being residential is that load is also more weather sensitive than it was pre-covid.

Concurrently, the economy has been slowly rebounding. The interplay of stay at home orders, weather sensitivity and economics, has contributed to varying COVID impacts on load. By the end of 2020 and early 2021, estimated impacts were a fraction of what they were at the pandemic's onset. Any lingering impacts of the pandemic going forward will be reflected in future load forecasts through the economic input variable.

Figure 2.9: 2020 COVID-19 Estimated Daily Energy Impacts 7-Day Moving Average



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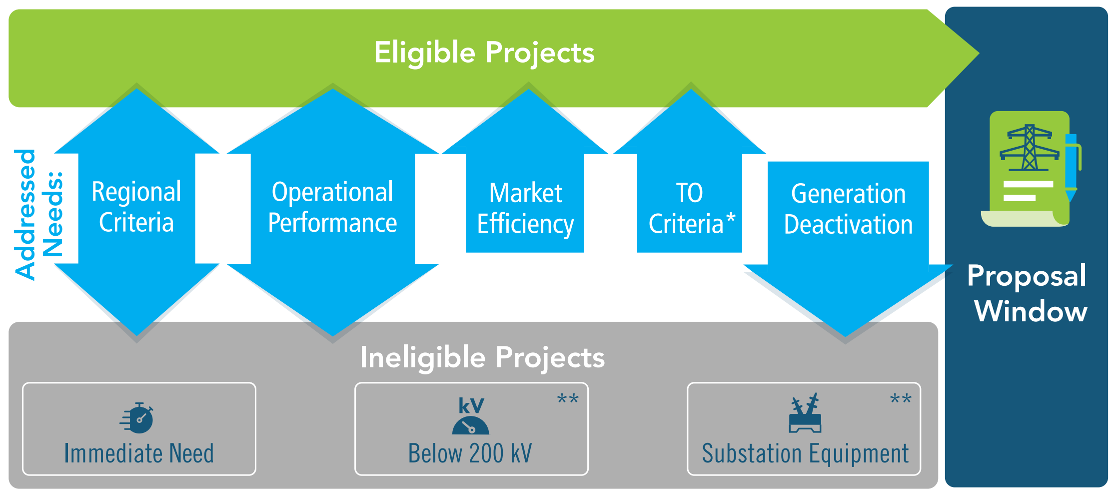
Section 3: Transmission Enhancements

3.0: 2020 RTEP Proposal Window No.1

Figure 3.1: RTEP Proposal Window Eligibility



Note: **TO Criteria is eligible for proposal windows as of Jan. 1, 2020.*
***Projects below 200 kV and substation equipment projects could become eligible for competition if multiple needs share common geography/contingency or if the project has multi-zonal cost allocation.*

RTEP Process Context

PJM seeks transmission proposals during each RTEP window to address one or more identified needs – reliability, market efficiency, operational performance and public policy. RTEP windows provide an opportunity for both incumbent and non-incumbent transmission developers to submit project proposals to PJM for consideration. When a window closes, PJM proceeds with analytical, company, constructability and financial evaluations to assess proposals for possible recommendation to the PJM Board. If selected, designated developers become responsible for project construction, ownership, operation, maintenance and financing.

PJM's Manual 14 series addresses the rules governing the RTEP process. In particular, Manual 14F describes PJM's competitive transmission process, including all aspects of analysis and evaluation pertaining to proposal windows. The manual provides one centralized source of business rules for stakeholders and PJM and is available on the PJM website.

Proposal Window Exemptions

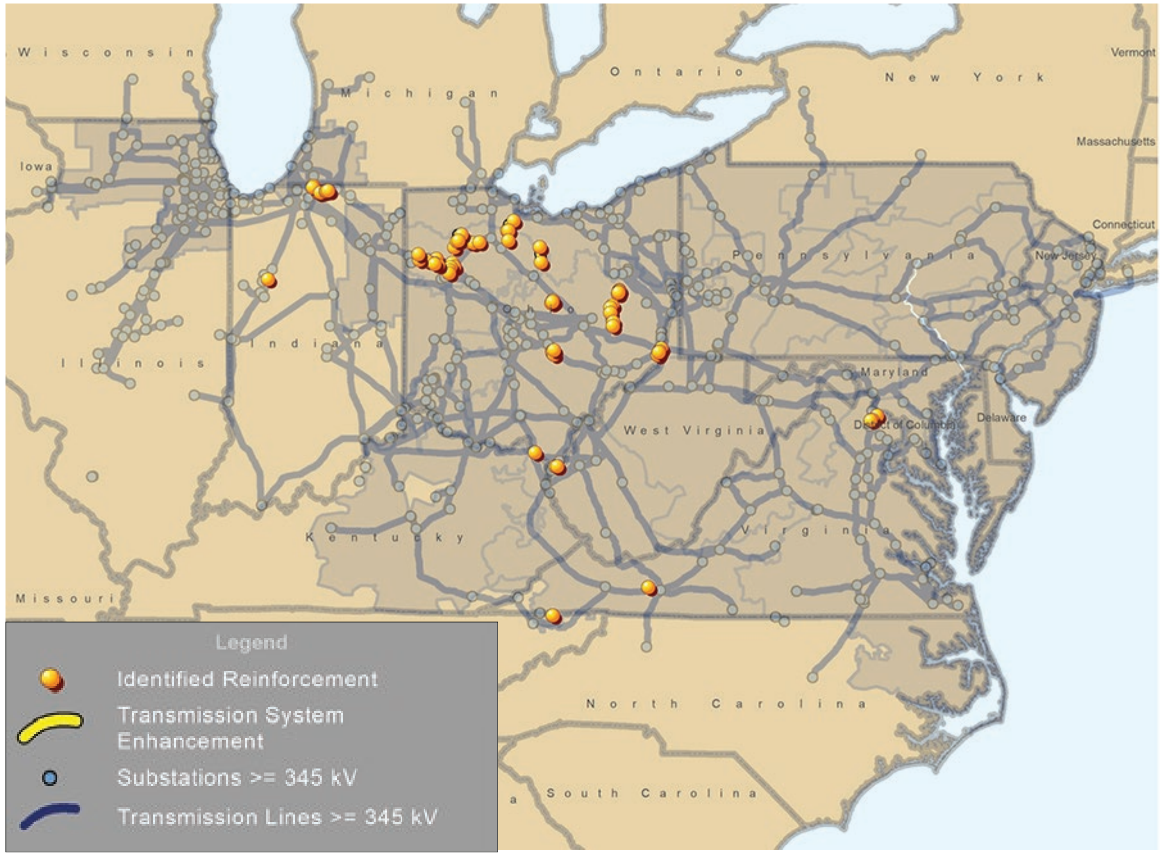
The following definitions explain the basis for excluding flowgates (a combination of an overloaded facility and the event that caused the overload) and/or projects from the competitive planning process. Exemptions are designated to the incumbent transmission owner (TO), as described in the PJM Operating Agreement, Schedule 6, Section 1.5.8.

These exemptions, as seen in **Figure 3.1** were developed with input from PJM stakeholders and have been approved by FERC:

- *Immediate-Need Exemption:* The required in-service date drives these projects, and they may be exempted from the competitive process to ensure they can be completed in advance of the required in-service date.
- *Below 200 kV:* Given the high likelihood that the selected solution will be designated to the incumbent TO, solutions below 200 kV are exempted from the competitive process.
- *Substation Equipment:* Due to identification of the limiting element(s) as substation equipment, these projects are designated to the incumbent TO, and therefore exempted.

Proposal Window Baseline Reliability Analysis Results
PJM's analysis of 2025 summer, winter and light load conditions identified 190 thermal and voltage criteria violations and one end-of-life criteria violation. A summary of the 191 violations is shown in **Map 3.1**.

Map 3.1: 2020 RTEP Baseline Thermal and Voltage Criteria Violations



RTEP Proposal Window No. 1 Proposals

RTEP Proposal Window No. 1, which contained 166 flowgates for competition, opened on July 1, 2020, and closed on Aug. 31, 2020. PJM received 47 proposals from eight entities. Eight of the proposals included cost containment provisions, and 11 of the proposals included greenfield construction. The proposals are shown in **Map 3.2** and **Table 3.1**.

Map 3.2: 2020 RTEP Proposal Window No. 1 Submittals

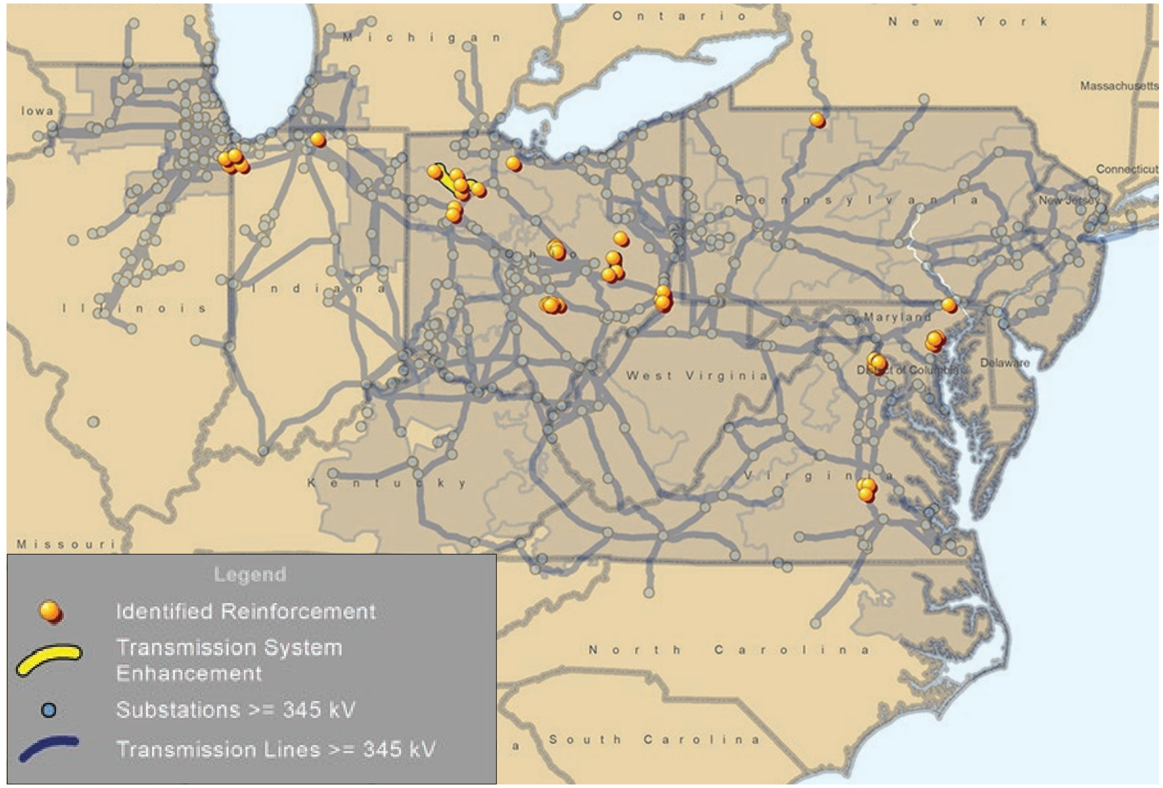


Table 3.1: 2020 RTEP Proposal Window No. 1 Submittals

PJM Proposal ID	Target Zone	kV	Analysis Type	Incumbent	Project Type	Cost Containment	Cost ($M)	Description
479	Dominion	230	Thermal, GenDeliv	VEPCO	Upgrade	No	$1.846	Line No. 2172 Partial Reconductor – Brambleton to Evergreen Mills
26							$2.316	Line No. 2172 Full Reconductor Brambleton to Evergreen Mills
740							$2.014	Line No. 2210 Partial Reconductor – Brambleton to Evergreen Mills
735							$2.257	Line No. 2210 Full Reconductor – Brambleton to Evergreen Mills – Full Reconductor

Table 3.1: 2020 RTEP Proposal Window No. 1 Submittals (Cont.)

PJM Proposal ID	Target Zone	kV	Analysis Type	Incumbent	Project Type	Cost Containment	Cost ($M)	Description
704	Dominion	230	Load Drop	VEPCO	Greenfield	No	$5.703	Waxpool Loop-Nimbus to Farmwell line extension
376	Dominion	230	Load Drop	VEPCO	Greenfield	No	$17.698	Waxpool Loop-Loop Line No. 2031 Option
883	Dominion	230	Load Drop	VEPCO	Greenfield	No	$41.203	Waxpool Loop-Shellhorn Option
493	Dominion	230	Thermal	VEPCO	Upgrade	No	$1.112	Line No. 2213 Partial Reconductor – Cabin Run to Yardley Ridge
134	Dominion	230	Thermal	VEPCO	Upgrade	No	$1.747	Line No. 2213 Full Reconductor – Cabin Run to Yardley Ridge
860	Dominion	230	Load Drop	VEPCO	Upgrade	No	$6.219	Relieve 300 MW Load Drop on Line No. 219 and Line No. 2066 (winter N-1-1, Tower, and faulted breaker)
575	ComEd	345	GenDeliv	NextEra	Upgrade	No	$8.250	Crete-St. John 345 kV Reconductoring Proposal
173	ComEd	345	GenDeliv	ComEd	Upgrade	No	$22.786	Reconductor 345 kV Line 94507 Crete-St. John
573	ComEd	345	GenDeliv	ComEd	Upgrade	No	$50.251	Reconductor 345 kV Lines 6607 East Frankfort-Crete and 94507 Crete-St. John
148	ComEd	345	GenDeliv	Central Transmission / LS Power	Greenfield	Yes	$29.629	Cedar Run-Cline 345 kV Transmission Project
281	ComEd	345	GenDeliv	ComEd	Upgrade	No	$42.485	Rebuild 345 kV double circuit Lines 94507 and 97008 Crete-St. John
354	ComEd	345	GenDeliv	ComEd	Upgrade	No	$88.935	Rebuild 345 kV Lines 6607/6608 East Frankfort-Crete and 94507/97008 Crete-St. John
241	ComEd	345	GenDeliv	ComEd	Upgrade	No	$12.000	Crete-St. John SmartValve
901	ComEd	345	GenDeliv	ComEd	Upgrade	No	$7.998	Install Series Inductor on Line 94507
393	ComEd	345	GenDeliv	AEP	Greenfield	Yes	$25.910	Zebedee 345 kV Greenfield Station
235	ComEd	345	GenDeliv	AEP	Greenfield	Yes	$46.194	Goodenow-Lemon Lake 345 kV Greenfield Line and Stations
602	AEP	69, 138, 35	Thermal	AEP	Greenfield	No	$25.930	North Woodcock-East Leipsic 69 kV Line
957	AEP	69, 138, 35	Thermal	AEP	Upgrade	No	$34.418	East Leipsic-New Liberty 138 kV Conversion
317	AEP	69, 138, 35	Thermal	Transource	Upgrade	Yes	$58.514	Richlands to East Lepsic 138 kV
341	AEP	69, 138, 35	Thermal	Transource	Greenfield	Yes	$27.149	East Leipsic-Maroe 69 kV Loop

Table 3.1: 2020 RTEP Proposal Window No. 1 Submittals (Cont.)

PJM Proposal ID	Target Zone	kV	Analysis Type	Incumbent	Project Type	Cost Containment	Cost ($M)	Description
608	AEP	69, 138, 35	Thermal	Transource	Greenfield	Yes	$25.157	East Leipsic to Maroe 69 kV Single Circuit
270	AEP	69	Thermal	Central Transmission / LS Power	Greenfield	Yes	$16.637	Birch Ridge-Natrium 138 kV Transmission Project
804	AEP	69, 138	Thermal, GenDeliv	AEP	Upgrade	No	$4.599	Kammer-Natrium Upgrades
538	AEP	69, 138	Thermal, GenDeliv	AEP	Upgrade	No	$5.635	Natrium Area Line Reconfiguration
182	AEP	69	Thermal	AEP	Upgrade	No	$15.884	Newcomerstown-Salt Fork Switch 69 kV Rebuild
109	AEP	69	Thermal	AEP	Upgrade	No	$4.309	West Cambridge Transformer Addition
628	AEP	69	Thermal	AEP	Upgrade	No	$1.466	Lancaster Area Switching Improvements
915	AEP	69	Thermal	AEP	Upgrade	No	$11.147	Lancaster Area Line Rebuilds
697	AEP	69, 138	Thermal	AEP	Upgrade	No	$1.286	Mount Vernon Area Line Reconfiguration
872	AEP	69, 138	Thermal	AEP	Upgrade	No	$12.846	Mount Vernon Area Line Rebuilds
494	BGE	115	GenDeliv	BGE	Upgrade	No	$4.692	Pumphrey Transformer Replacement
763	BGE	115	GenDeliv	BGE	Upgrade	No	$0.000	Erdman Reconfiguration
514	BGE	115	GenDeliv	BGE	Upgrade	No	$9.010	Pumphrey-Graceton Transformer Replacement
420	BGE	115	GenDeliv	BGE	Upgrade	No	$14.730	Constitution-Concord 110567/110568 Reconductor – Partial 110563/110564 Reconductor
836	BGE	115	GenDeliv	BGE	Upgrade	No	$20.587	Constitution-Concord 110567/110568 Concord-Monument Street 110563/110564 Reconductor
962	BGE	115	GenDeliv	BGE	Upgrade	No	$19.422	Pumphrey Transformer, Constitution-Concord 110567/110568 Reconductor, Partial 110563/110564 Reconductor
191	BGE	115	GenDeliv	BGE	Upgrade	No	$25.279	Pumphrey Transformer, Constitution-Concord 110567/110568 Concord-Monument Street 110563/110564 Reconductor
721	Dominion	230	Thermal, GenDeliv, Load Drop	Central Transmission / LS Power	Greenfield	Yes	$29.250	Stonewater-Waxpool 230 kV Transmission Project
855	PENELEC	345	Voltage, Voltage and Magnitude	ATSI / MAIT	Upgrade	No	$8.077	Pierce Brook Substation, Install Second 345 kV Reactor

Table 3.1: 2020 RTEP Proposal Window No. 1 Submittals (Cont.)

PJM Proposal ID	Target Zone	kV	Analysis Type	Incumbent	Project Type	Cost Containment	Cost ($M)	Description
179	AEP	35, 69	Thermal	AEP	Upgrade	No	$2.020	West New Philadelphia Breaker Installation
848		35					$1.471	Rockhill Circuit Switcher Install
503		69					$1.758	Fremont Breaker and Bloom Road Cap Bank Installation
308		35					$4.894	Dragoon Transformer and Line Addition

RTEP Proposal Window No. 2 Proposals

RTEP Proposal Window No. 2, which contained one flowgate for competition, opened on July 1, 2020, and closed on July 31, 2020. The one flowgate was as a result of Dominion's FERC 715 criteria for end-of-life facilities on the Goose Creek-Doubs 500 kV transmission line. The end-of-life issue identified for the Goose Creek-Doubs 500 kV line is linked to the Attachment M3 process need identified as APS-2020-011. PJM received one proposal from Dominion, the incumbent TO, to rebuild Dominion's portion of the line. The proposal is shown in **Map 3.3** and **Table 3.2**.

Map 3.3: 2020 RTEP Proposal Window No. 2 Submittals

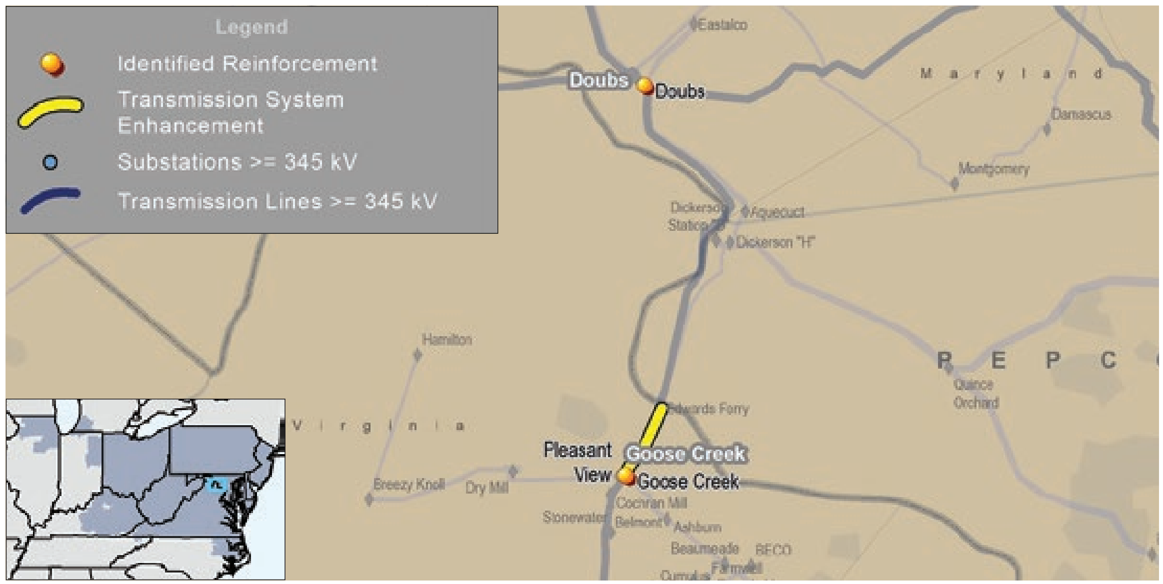


Table 3.2: 2020 RTEP Proposal Window No. 2 Submittals

Proposal ID	Target Zone	kV	Analysis Type	Incumbent	Project Type	Cost Containment	Cost ($M)	Project Description
441	Dominion	500	End-of-Life	VEPCO	Upgrade	No	7.641	Line No. 514, Goose Creek-Doubs (FE) 500 kV Line Rebuild

RTEP Proposal Window No. 3 Proposals

RTEP Proposal Window No. 3, which contained 24 flowgates for competition, opened on Sept. 18, 2020, and closed on Oct. 19, 2020. Eight flowgates were from RTEP Proposal Window No. 1 violations and 16 flowgates were new to RTEP Proposal Window No. 3. The flowgates were in relation to AEP's FERC 715 criteria of thermal overloads on the following facilities, along with FirstEnergy's FERC 715 criteria short-circuit violations on Greenfield 69 kV breaker 501-B-251:

- Pittsburgh-West Mount Vernon 69 kV
- West Mount Vernon 138/69 kV
- South Mount Vernon-North Mount Vernon 69 kV
- North Mount Vernon-Mount Vernon 69 kV

PJM received two proposals, one from AEP, the incumbent TO, and one joint greenfield proposal from Central Transmission and LS Power. The proposals are shown in **Map 3.4** and **Table 3.3**.

Map 3.4: 2020 RTEP Proposal Window No. 3 Submittals

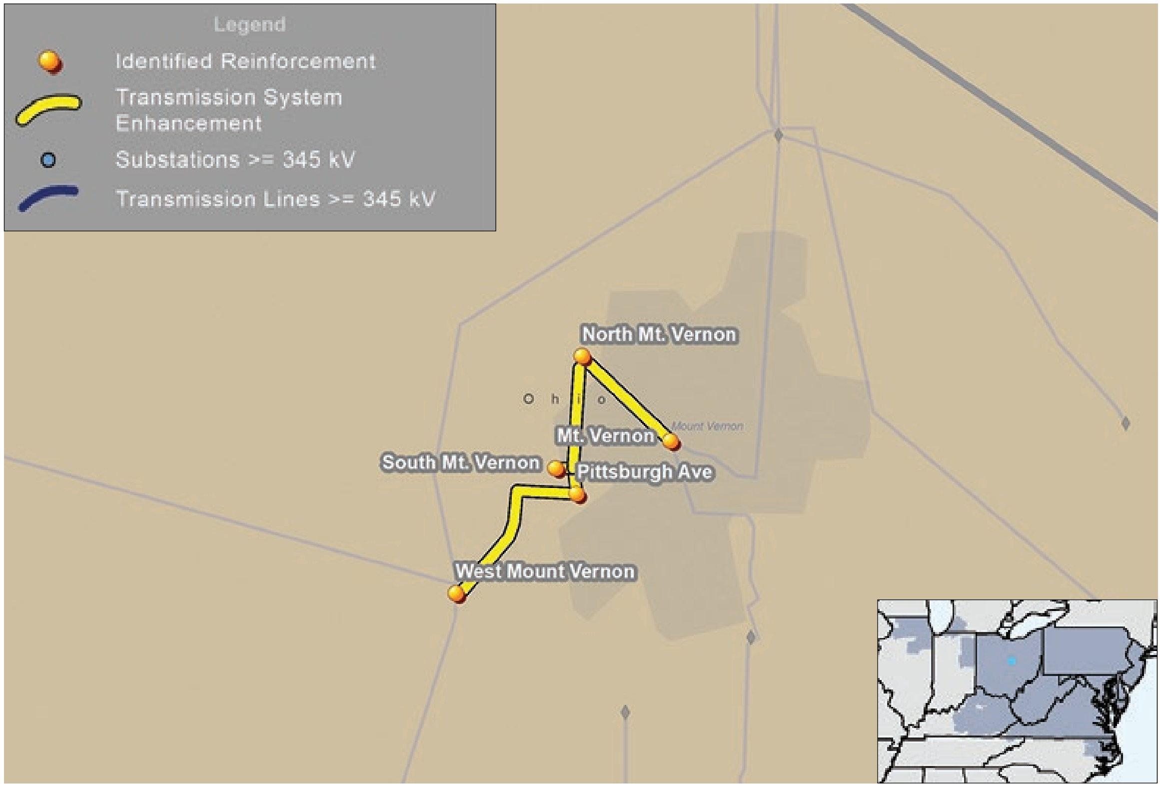


Table 3.3: 2020 RTEP Proposal Window No. 3 Submittals

Proposal ID	Target Zone	kV	Analysis Type	Incumbent	Project Type	Cost Containment	Cost ($M)	Project Description
533	AEP	69, 138	Thermal	Central Transmission / LS Power	Greenfield	Yes	$21.129	Wolf Run-Gambier-Martinsburg Transmission Project
860				AEP	Upgrade	No	$12.926	West Mount Vernon Area Rebuilds

3.1: Transmission Owner Criteria

3.1.1 — Transmission Owner FERC Form 715 Planning Criteria

The PJM Operating Agreement specifies that individual TO planning criteria are to be evaluated as a part of the RTEP process, in addition to NERC and PJM regional criteria. Frequently, TO planning criteria address specific local system conditions such as in urban areas. TOs are required to include their individual criteria as part of their respective FERC Form 715 filings. TO criteria can be found on the PJM website. PJM applies TO criteria to all facilities included in the PJM Open Access Transmission Tariff (OATT) facility list.

Transmission enhancements driven by TO criteria are considered RTEP baseline projects. Projects may be eligible for proposal window consideration as shown in **Figure 3.1**. Under the terms of the OATT, the costs of such projects follow existing baseline reliability cost allocation rules. The description and location of those projects with an estimated cost of $10 million or greater are shown in **Table 3.4** and **Map 3.5**. More detailed descriptions of these projects can be found in TEAC PJM Board White Papers.

In situations where the TO is not able to complete construction by the required in-service date, PJM works to establish operating procedures to ensure that the system remains reliable until the reinforcement is in service.

NOTE:
Per FERC Order EL19-61, PJM has eliminated the FERC Form 715 transmission owner criteria exclusion from the competitive proposal windows as of Jan. 1, 2020.

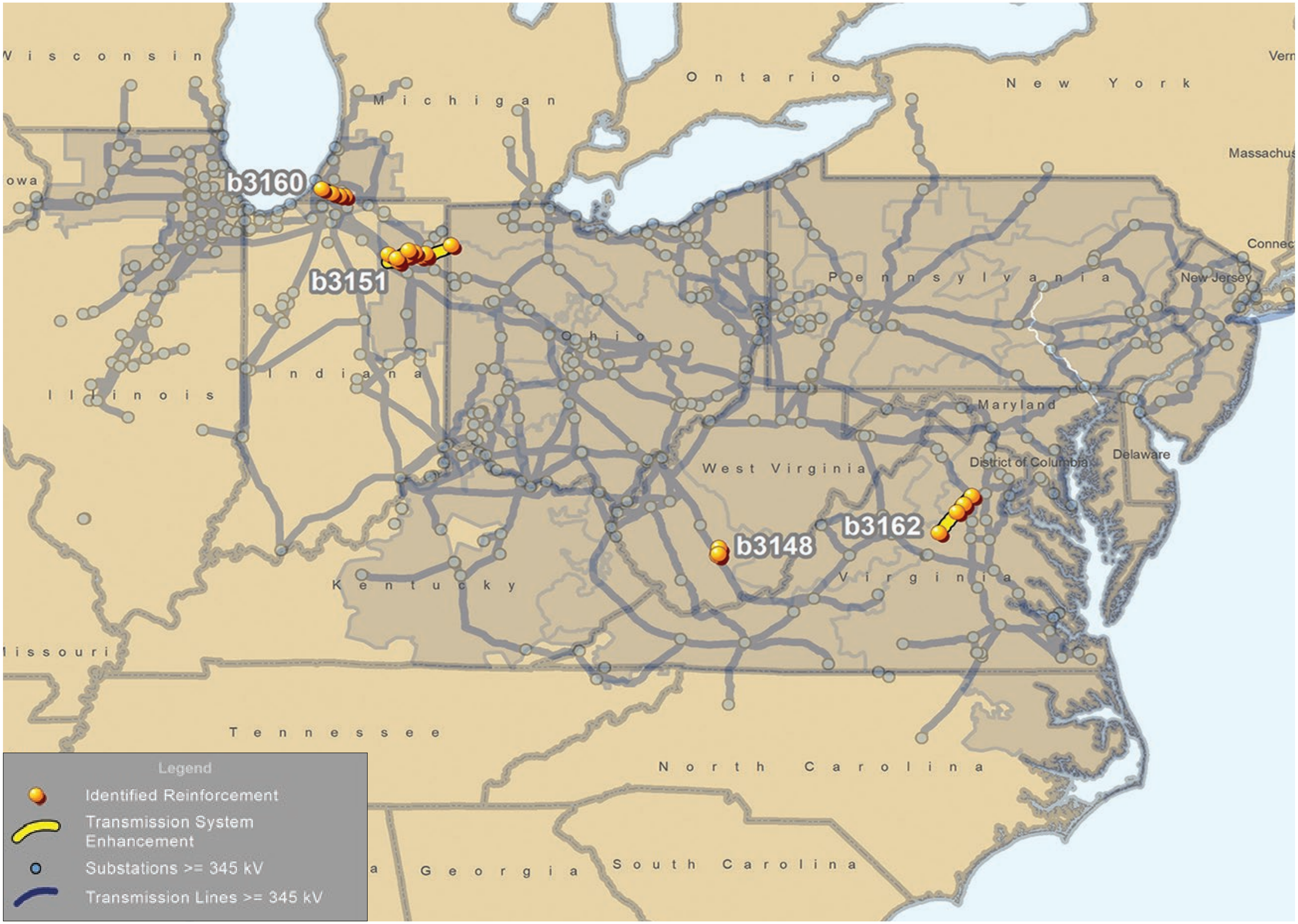
Table 3.4: Transmission Owner Criteria Projects (Greater Than or Equal to $10 Million)

Upgrade ID	Description	TO Zone	Estimated Cost ($M)	Required In-Service	Projected In-Service
B3148	Rebuild the 46 kV Bradley-Scarbro line to 96 kV standards using 795 ACSR to achieve a minimum rating of 120 MVA. Rebuild the new line adjacent to the existing one leaving the old line in service until the work is completed.	AEP	$27.7	12/1/2021	12/1/2021
	Bradley remote end station work, replace 46 kV bus, install new 12 MVAR capacitor bank.				12/10/2020
	Replace the existing switch at Sun substation with a two-way SCADA-controlled MOAB switch.				
	Remote end work and associated equipment at Scarbro Station.				5/6/2021
	Retire Mt. Hope Station and transfer load to existing Sun Station.				12/10/2020
B3151	Rebuild the ~30 mile Gateway-Wallen 34.5 kV circuit as the ~27 mile Gateway-Wallen 69 kV circuit.		$113.0	6/1/2024	6/23/2022
	Rebuild the 2.5 mile Columbia-Gateway 69 kV line.				4/3/2023
	Rebuild Columbia station in the clear as a 138/69 kV station with two 138/69 kV transformers and four-breaker ring buses on the high and low side. Station will reuse 69 kV breakers J & K and 138 kV breaker D.				6/1/2024

Table 3.4: Transmission Owner Criteria Projects (Greater Than or Equal to $10 Million) (Cont.)

Upgrade ID	Description	TO Zone	Estimated Cost ($M)	Required In-Service	Projected In-Service
B3151	Rebuild the 13 mile Columbia-Richland 69 kV line.	AEP	$113.0	6/1/2024	6/1/2024
	Rebuild the 0.5 mile Whitley-Columbia City No. 1 line as 69 kV.				
	Rebuild the 0.5 mile Whitley-Columbia City No. 2 line as 69 kV.				
	Rebuild the 0.6 mile double circuit section of the Rob Park-South Hicksville/Rob Park-Diebold Road as 69 kV.				
	Retire the ~3 mile Columbia-Whitley 34.5 kV line.				
	At Gateway station, remove all 34.5 kV equipment and install one 69 kV circuit breaker for the new Whitley line entrance.				
	Rebuild Whitley as a 69 kV station with two line and one bus tie circuit breakers.				
	Replace the Union 34.5 kV switch with a 69 kV switch structure.				
	Replace the Eel River 34.5 kV switch with a 69 kV switch structure.				
	Install a 69 kV Bobay switch at Woodland Station.				
	Replace Carroll and Churubusco 34.5 kV stations with the 69 kV Snapper station. Snapper will have two line circuit breakers, one bus tie circuit breaker and a 14.4 MVAR cap bank.				
	Remove 34.5 kV circuit breaker AD at Wallen station.				
B3160	Construct a ~2.4 mile double circuit 138 kV extension using 1033 ACSR to connect Lake Head to the 138 kV network.	AEP	$36.2	6/1/2024	4/3/2023
	Retire the ~2.5 mile 34.5 kV Niles-Simplicity tap line.				11/29/2022
	Retire the ~4.6 mile Lakehead 69 kV tap.				6/15/2023
	Build new 138/69 kV drop down station to feed Lakehead with a 138 kV breaker, 138 kV switcher, 138/69 kV transformer and a 138 kV MOAB.				4/15/2023
	Rebuild the ~1.2 mile Buchanan South 69 kV radial tap using 795 ACSR.				
	Rebuild the ~8.4 mile 69 kV Pletcher-Buchanan Hydro line as the ~9 mile Pletcher-Buchanan South 69 kV line using 795 ACSR.				
	Install a phase-over-phase switch at Buchanan South station with two line MOABs.				
B3162	Acquire land and build a new 230 kV switching station Stevensburg with a 224 MVA, 230/115 kV transformer. Gordonsville-Remington 230 kV Line No. 2199 will be cut and connected to the new station. Remington-Mt. Run 115 kV Line No. 70 and Mt. Run-Oak Green 115 kV Line No. 2 will also be cut and connected to the new station.	Dominion	$22.0	6/1/2024	12/31/2023

Map 3.5: Transmission Owner Criteria Projects (Greater Than or Equal to $10 Million)



3.2: Supplemental Projects

Supplemental projects are not required for compliance with system reliability, operational performance or market efficiency economic criteria, as determined by PJM. They are transmission expansions or enhancements that enable the continued reliable operation of the transmission system by meeting customer service needs, enhancing grid resilience and security, promoting operational flexibility, addressing transmission asset health, and ensuring public safety, among other drivers. Supplemental projects may also address reliability issues for transmission facilities that are not considered under NERC requirements or other PJM criteria. Maintenance work and emergency work (e.g., work that is unplanned, including necessary work resulting from an unanticipated customer request, repair of equipment or facilities damaged by storms or other causes, or replacement of failing or failed equipment) do not constitute supplemental projects.

While not subject to PJM Board approval, supplemental projects are included in PJM's RTEP models. FERC-approved, TO owned, Attachment M3 of the PJM Tariff provides additional procedures that PJM and TOs follow for supplemental projects. PJM, in its role as a facilitator in the Attachment M3 process, is responsible for the following:

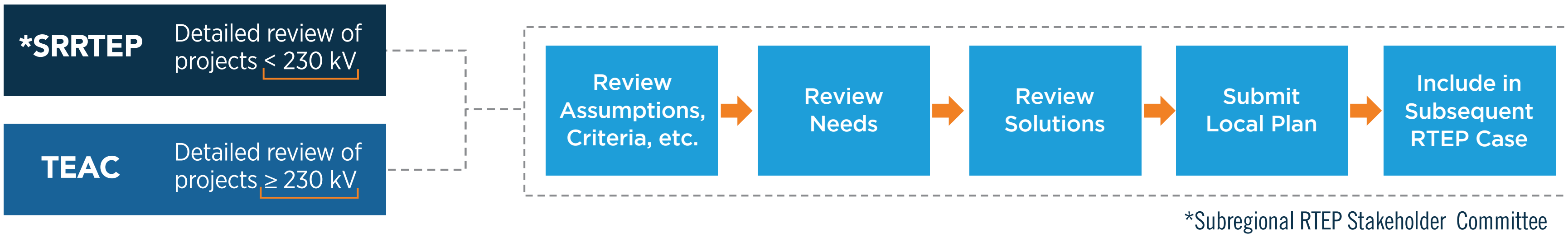
- *Provide necessary facilitation and logistical support* so that supplemental project planning meetings can be conducted as outlined in Attachment M3 of the PJM Tariff.
- *Provide the applicable TO with modeling information* so that TOs can determine if a stakeholder-proposed project can address a supplemental project need.
- *Perform do-no-harm analysis* to ensure that a supplemental project that a TO elects for inclusion in its local plan does not cause additional reliability violations.
- Work with TOs and stakeholders to improve Attachment M3 transparency.

Figure 3.2: Primary Supplemental Project Drivers

Customer Service	Provide service to new and existing customers; interconnect new customer load; address distribution load growth, customer outage exposure, equipment loading, etc.
Equipment Material Condition, Performance and Risk	Address degraded equipment performance, material condition, obsolescence; end of the useful life of equipment or a facility; equipment failure; employee and public safety; environmental impact.
Operational Flexibility and Efficiency	Optimize system configuration, equipment duty cycles and restoration capability; minimize outages.
Infrastructure Resilience	Improve system ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event, including severe weather or geomagnetic disturbances.
Other	Meet objectives not included in other definitions such as, but not limited to, technological pilots, industry recommendations, environmental and safety impacts, etc.

Figure 3.2 reflects the primary drivers of supplemental projects. Transmission expansions or enhancements that replace facilities that are near or at the end of their useful lives are a primary focus of equipment material condition, performance and risk. TOs develop and apply their own factors and considerations for addressing facilities at or near the end of their useful lives. Each TO explains the criteria, assumptions and models it uses to identify project drivers at the annual assumptions meeting provided under the Attachment M3 process.

Figure 3.3: Attachment M3 Process for Supplemental Projects

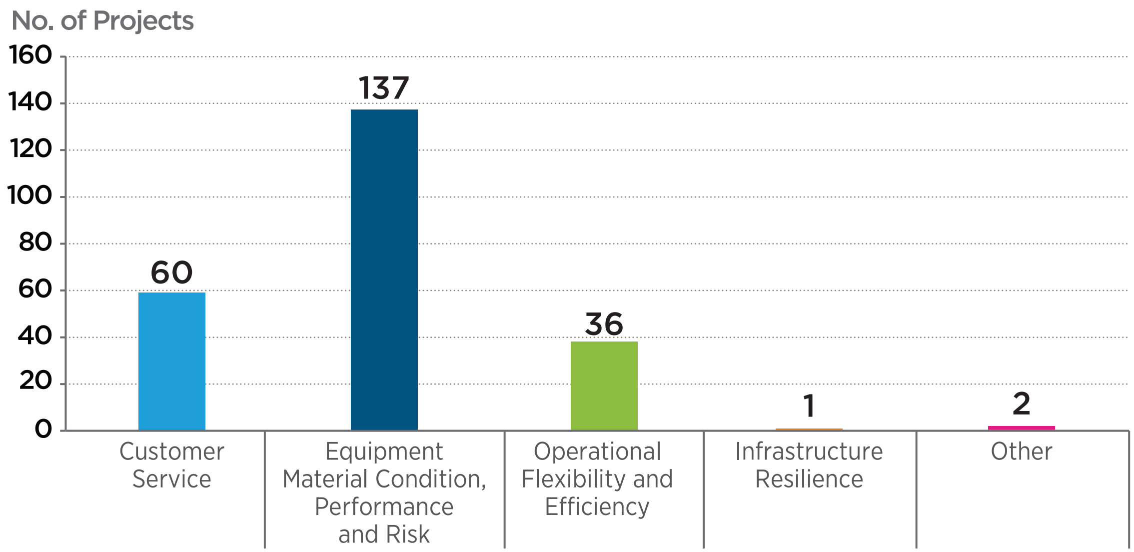


The Attachment M3 process leverages PJM's TEAC and subregional RTEP committees, which provides stakeholders a meaningful opportunity to participate and provide feedback, including written comments, throughout the transmission planning process for supplemental projects, as shown in **Figure 3.3**. Stakeholder interested in providing feedback can do so via PJM's Planning Community.

2020 Supplemental Projects

PJM evaluated approximately $4.7 billion of TO supplemental projects in 2020. **Figure 3.4** shows a breakdown of supplemental solutions by driver, presented at TEAC and subregional RTEP committees over the past year, and suggests that the largest driver is equipment material condition, performance and risk. In 2020, projects driven solely by equipment material condition, performance and risk add up to a total of approximately $2.6 billion, while projects driven by customer service requests and operational flexibility and efficiency totaled approximately $615 million and $154 million, respectively.

Figure 3.4: 2020 Supplemental Projects by Driver



PJM | DE | DC | IL | IN | KY | MD | MI | NJ | NC | OH | PA | TN | VA | WV

3.3: Generator Deactivations

PJM received 22 deactivation notices, including new requests and revisions to existing requests, totaling 4,428 MW during 2020. **Map 3.6** and **Table 3.5** show the 10 generators being deactivated with a capacity greater than or equal to 100 MW. The remaining 12 generators had a combined capacity of 164 MW. Deactivation notifications in 2020 included nine coal-unit deactivations totaling 2,466 MW. Overall capacity value of deactivation notifications for units greater than or equal to 100 MW totaled 4,263.7 MW in 2020. PJM completed the required analysis to identify reliability criteria violations caused by deactivations. Several deactivations required the completion of existing baseline enhancements, and others had no reliability impacts identified. No new baseline upgrades were identified for the deactivation notifications in 2020.

All units studied in 2020 can retire as requested; operational flexibility will allow PJM to bridge any delays with the completion of required transmission enhancements. On March 13, 2020, PJM received reinstatement notifications from Energy Harbor for the Beaver Valley 1 and 2, and Pleasants Power Station 1 and 2 units, totaling over 3,080 MW. PJM also received reinstatement notification from Colver Power for the Colver non-utility generator, totaling 110 MW. These units will not be deactivating.

Map 3.6: Deactivation Notifications in 2020 Greater Than or Equal to 100 MW

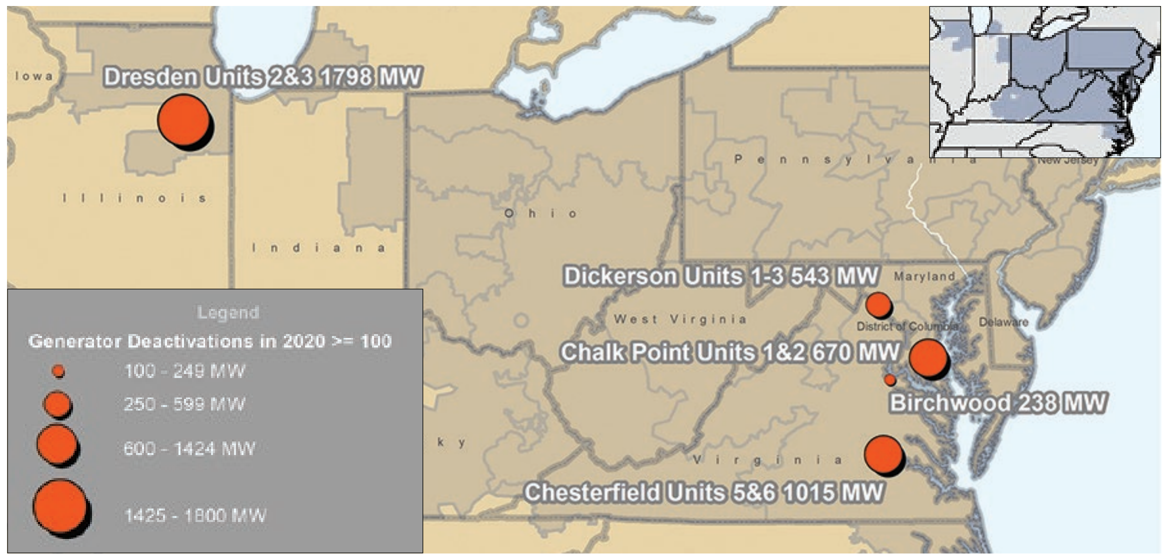


Table 3.5: Deactivation Notifications in 2020 (Greater Than or Equal to 100 MW)

<table>
<tr><th>Unit</th><th>Capacity (MW)</th><th>TO Zone</th><th>Age (Years)</th><th>Fuel Type</th><th>Request Submittal Date</th><th>Actual/Projected Deactivation Date</th></tr>
<tr><td>Birchwood Plant</td><td>238.0</td><td>Dominion</td><td>24</td><td>Coal</td><td>10/6/2020</td><td>3/1/2021</td></tr>
<tr><td>Dresden 3</td><td>895.5</td><td rowspan="2">ComEd</td><td>49</td><td rowspan="2">Nuclear</td><td rowspan="2">8/27/2020</td><td rowspan="2">11/1/2021</td></tr>
<tr><td>Dresden 2</td><td>902.5</td><td>50</td></tr>
<tr><td>Chalk Point Unit 2</td><td>337.2</td><td rowspan="5">PEPCO</td><td>55</td><td rowspan="7">Coal</td><td rowspan="2">8/10/2020</td><td rowspan="2">6/1/2021</td></tr>
<tr><td>Chalk Point Unit 1</td><td>333.1</td><td>56</td></tr>
<tr><td>Dickerson Unit 3</td><td>180.5</td><td>58</td><td rowspan="3">5/15/2020</td><td rowspan="3">8/13/2020</td></tr>
<tr><td>Dickerson Unit 2</td><td>180.0</td><td>60</td></tr>
<tr><td>Dickerson Unit 1</td><td>182.0</td><td>61</td></tr>
<tr><td>Chesterfield 6</td><td>678.1</td><td rowspan="2">Dominion</td><td>51</td><td rowspan="2">2/20/2020</td><td rowspan="2">5/31/2023</td></tr>
<tr><td>Chesterfield 5</td><td>336.8</td><td>56</td></tr>
</table>

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

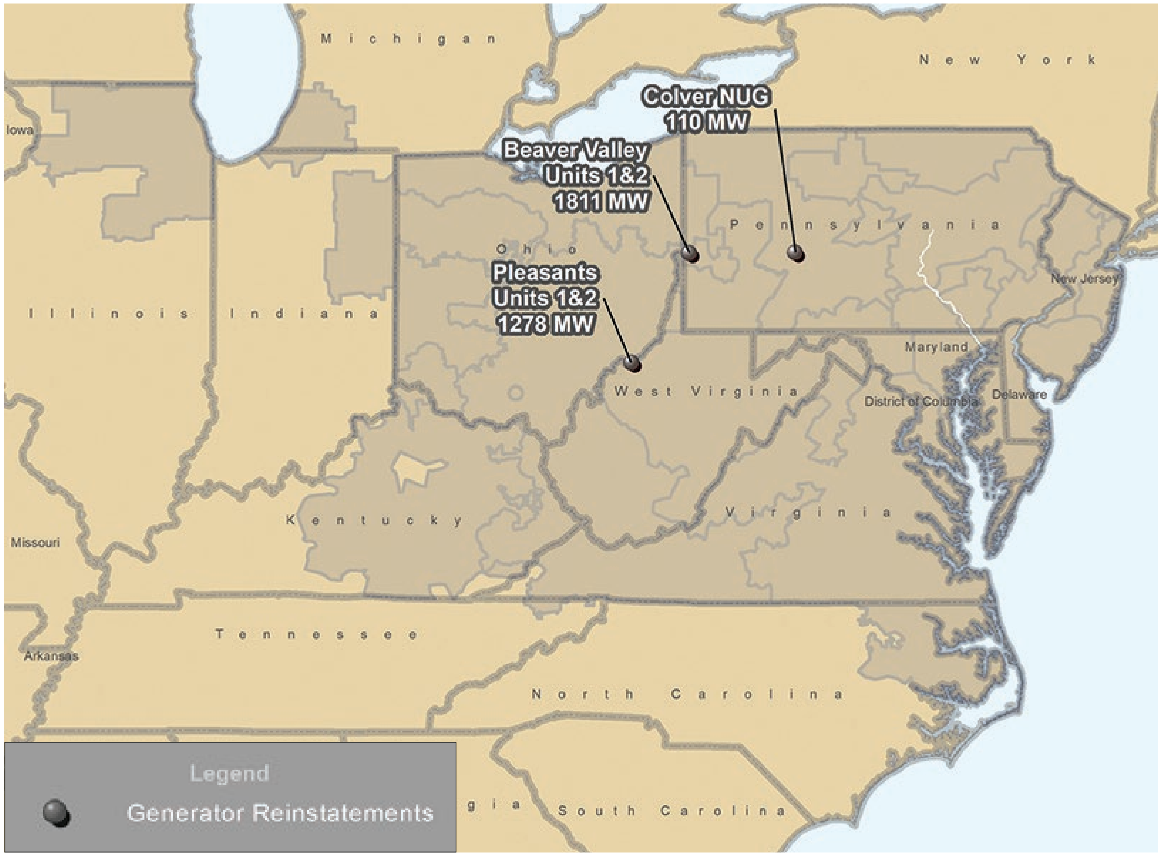
3.4: 2020 Re-Evaluations

As part of each RTEP cycle, PJM evaluates how changing input assumptions impact the results of analysis. Individual generator or load modeling changes are studied as a sensitivity to understand their impact to the transmission system. But, when a large set of input assumptions change, a full re-evaluation of these changing impact assumptions is required. This re-evaluation, known as a retool, allows for assumptions to be updated in the model used for analysis, and re-analyzed to understand their impacts.

As part of the 2020 RTEP, PJM performed a retool of the 2025 RTEP analysis, driven by the withdrawn deactivation of the Beaver Valley 1 and 2, Pleasants Power Station units 1 and 2 and the Colver units shown in **Map 3.7**, which had previously announced their intent to deactivate. This retool led to the cancellation of baseline upgrades, previously identified for these units to deactivate without creating reliability criteria violations.

Additionally, retool analysis continues, to determine if upgrades identified in previous analysis are still valid. Several baseline upgrades are still required for other deactivations in these areas. A detailed description of the withdrawn deactivation analysis can be found on the PJM website.

Map 3.7: Withdrawn Deactivations Greater Than or Equal to 100 MW



PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

3.5: Interregional Planning

3.5.1 — Adjoining Systems

PJM's interregional planning activities continue to foster increased interregional coordination. The nature of these activities includes structured, Tariff-driven analyses, as well as sensitivity evaluations to target specific issues that may arise each year. PJM currently has interregional planning arrangements with the New York Independent System Operator (NYISO), the Independent System Operator of New England (ISO-NE), the Mid-Continent Independent System Operator (MISO), the Tennessee Valley Authority (TVA), and to the south through the Southeastern Regional Transmission Planning process (SERTP), shown on **Map 3.8**.

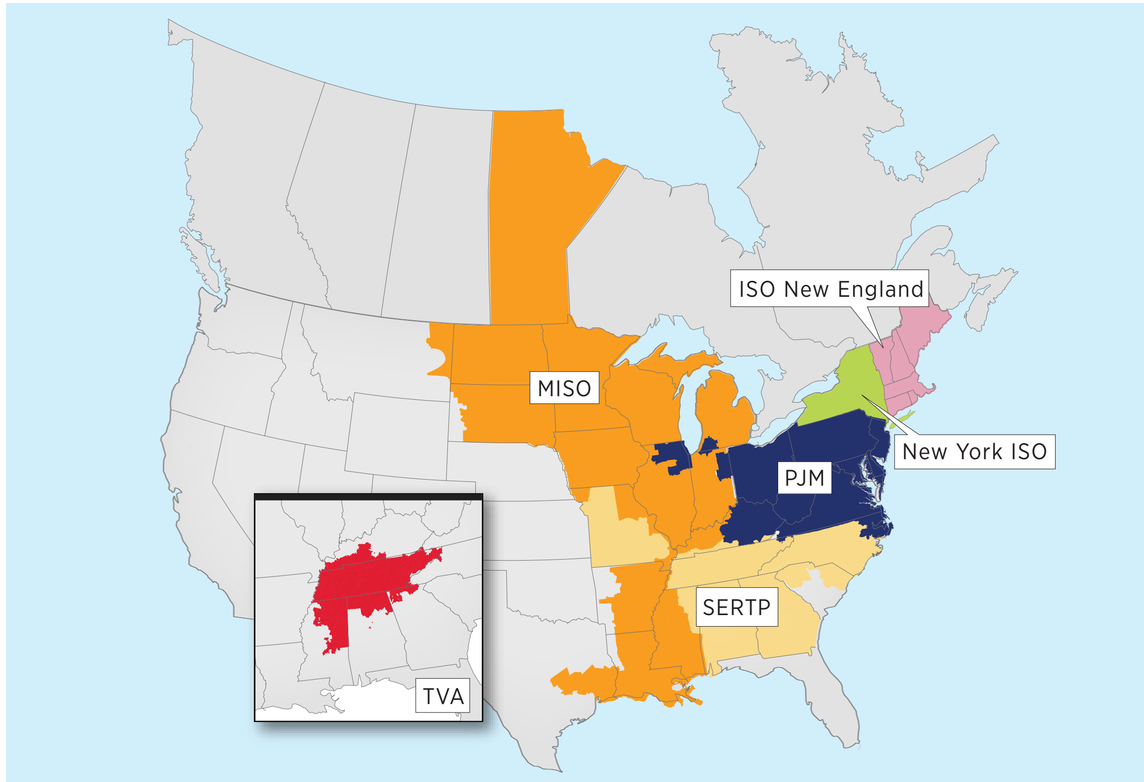
In addition, PJM actively participates in the Eastern Interconnection Planning Collaborative.

Interregional Agreements

Under each interregional agreement, provisions governing coordinated planning ensure that critical cross-border operational and planning issues are identified and addressed before they impact system reliability or adversely impact efficient market administration. The planning processes applicable to each of PJM's three external transmission interfaces include provisions to address issues of mutual concern, including:

- Interregional impacts of regional transmission plans
- Impacts of queued generator interconnection requests and deactivation requests
- Opportunities for improved market efficiencies at interregional interfaces
- Solutions to reliability and congestion constraints
- Interregional planning impacts of national and state public policy objectives
- Enhanced modeling accuracy within individual planning processes due to periodic exchange of power system modeling data and information

Map 3.8: PJM Interregional Planning



Each study is conducted in accordance with the PJM Tariff and respective interregional agreement. Studies may include cross-border analyses that examine reliability, market efficiency or public policy needs. Reliability studies may assess power transfers, stability, short circuit, generation, merchant transmission interconnection analyses and generator deactivation. Taken together, these coordinated planning activities enhance the reliability, efficiency and cost effectiveness of regional transmission plans.

Table 3.6: PJM Market Efficiency Eligible Market-to-Market Congestion Drivers

2020/2021 RTEP Market Efficiency Window

Eligible Congestion Drivers			
Constraint	**From Area**	**To Area**	**Comment**
Duff to Francisco 345 kV	DUK-IN	DUK-IN	Market-to-Market Constraint
Gibson to Francisco 345 kV			

3.5.2 — MISO

The 2020 planning efforts under Article IX of the MISO/PJM joint operating agreement ensure the coordination of regional reliability, market efficiency, interconnection requests and deactivation notifications. Interconnection-driven network transmission enhancements are summarized in **Section 5**. Deactivation-driven baseline analyses are summarized in **Section 3.4**. Annually, stakeholder input and feedback to the interregional planning process is coordinated through the MISO/PJM Interregional Planning Stakeholder Advisory Committee (IPSAC).

Following the Annual Issues Review in the first quarter of 2020, PJM and MISO confirmed their commitment to identify market efficiency issues in the fourth quarter.

PJM identified two congestion drivers as candidates for potential interregional market efficiency projects. This is shown in **Table 3.6,** PJM Market Efficiency Eligible Market-to-Market Congestion Drivers. Additionally, the interregional planning process sought to identify interregional reliability projects that were more efficient or cost effective than the alternative regional plans. No drivers for a potential interregional reliability project were identified in 2020.

Based on the annual issues review and stakeholder feedback, no significant drivers for other interregional studies were identified. No other interregional studies were conducted under the Coordinated System Plan (CSP) in 2020.

3.5.3 — Update on 2018/2019 PJM/MISO Interregional Market Efficiency Study

Periodically, the Joint RTO Planning Committee (JRPC), with input from IPSAC, may elect to perform a longer-term CSP study. After review of each RTO's transmission issues and regional solutions, the JRPC initiated a two-year IMEP study in 2018. This follows the CSP study process, including close coordination with PJM and MISO regional market efficiency analyses. For more information on PJM's regional market efficiency process, see **Section 4**.

The 2018/2019 IMEP study resulted in one interregional project to be recommended by both RTOs. The Bosserman-Trail Creek-Michigan City 138 kV project will address persistent historical congestion projected to continue on the NIPSCO/AEP seam. See **Section 4.1** for full details on the Bosserman-Trail Creek-Michigan City project.

The Bosserman-Trail Creek-Michigan City project was approved by the PJM Board in December 2019, conditionally on MISO approval of the same project. At that time, MISO has not completed final approval of the project because of pending filings at FERC regarding regional cost allocation for interregional projects under 345 kV. Since the 2019 provisional approval, FERC approved MISO's cost allocation compliance filing on July 28, 2020, allowing for MISO's board to approve the project on Sept. 17, 2020.

The project was fully approved by the PJM Board in December 2020. The estimated cost for this project is $24.69 million ($22 million of which is allocated to PJM, with a required and projected in-service date of January 2023). The local transmission owners, AEP and NIPSCO, will be designated to complete this work.

3.5.4 — New York ISO and ISO New England

In 2020, PJM, the New York ISO and ISO New England reviewed the status of the ongoing work plan and anticipated 2021 activities. The 2020 work included continued coordination, a review of transmission needs and solutions proposed by neighboring systems, coordination of the interconnection queue, long-term firm transmission service, and transmission projects that potentially impact interregional system performance. The group continues to seek opportunities for interregional transmission. The next Northeast Coordinated System Plan is anticipated by the second quarter of 2022.

3.5.5 — Adjoining Systems South of PJM

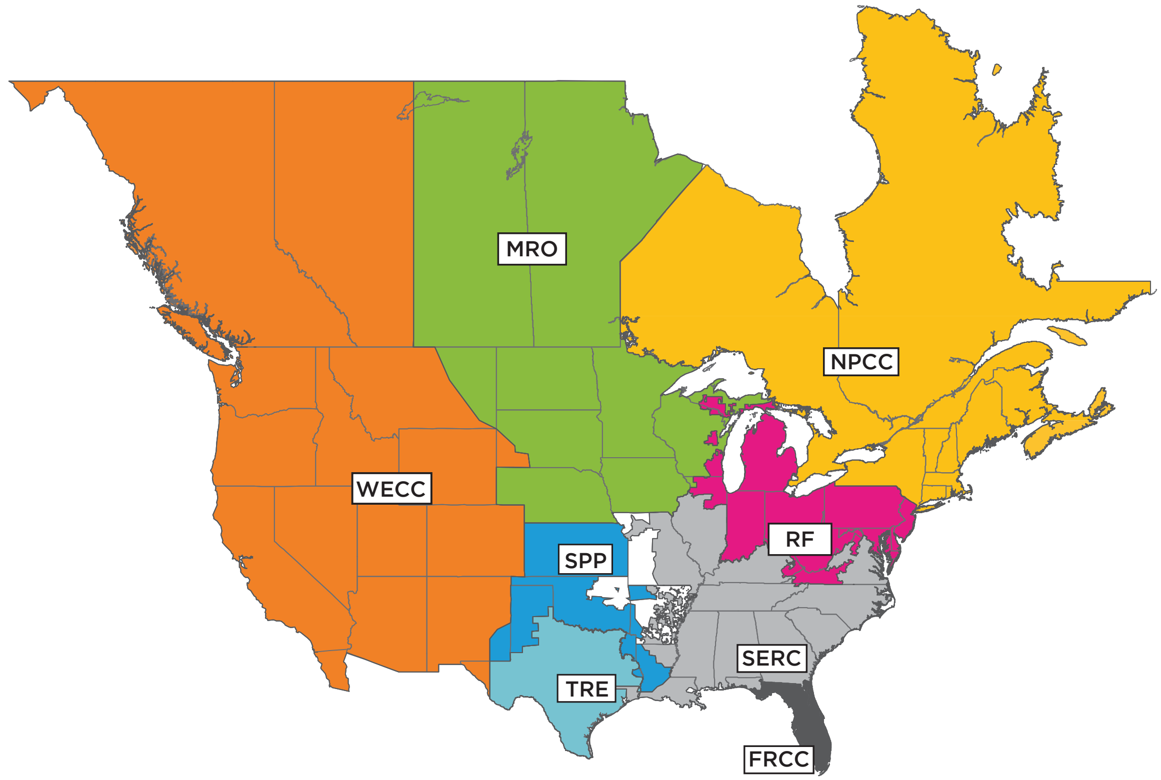
Interregional planning activities with entities south of PJM are conducted mainly under the auspices of the SERTP process and SERC Reliability Corp.

Southeastern Regional Transmission Planning

PJM and the SERTP, shown earlier on **Map 3.8**, continued interregional data exchange and interregional coordination during 2020. SERTP membership includes several entities under FERC jurisdiction and voluntary participation among six non-jurisdictional entities. The jurisdictional entities include Southern Co., Duke Energy (including Duke Energy Carolinas and Duke Energy Progress) and LGE/KU. Duke Energy and LGE/KU are directly connected to PJM. Of the non-jurisdictional entities, only TVA is directly connected to PJM. The remaining five SERTP participants are planning areas south and west of Duke Energy and TVA.

SERTP input occurs through each region's respective planning process stakeholder forums. Stakeholders who have reviewed their respective region's needs and transmission plans may provide input regarding any potential interregional opportunities that may be more efficient or cost effective than individual regional plans. Successful interregional project proposals can displace the respective regional plans. PJM discussions of SERTP planning, as well as reports on other interregional planning, occur at the Transmission Expansion Advisory Committee (TEAC). The SERTP regional process itself can be followed at www.southeasternrtp.com.

Map 3.9: NERC Areas



SERC Activities

PJM continues to support its members that are located within SERC – shown on **Map 3.9**. That support includes active participation in the Planning Coordination Subcommittee, the Long-Term Working Group, the Dynamics Working Group, the Short-Circuit Database Working Group, the Resource Adequacy Working Group and the Near-Term Working Group.

PJM actively contributed to SERC committee and working group activities to coordinate 2020 model development and study activities.

PJM transmission owners in the SERC region include Dominion and East Kentucky Power Cooperative (EKPC).

3.5.6 — Eastern Interconnection Planning Collaborative

The Eastern Interconnection Planning Collaborative (EIPC) is an interconnection-wide transmission planning coordination effort among NERC Planning Authorities in the Eastern Interconnection, shown on **Map 3.10**. EIPC consists of 20 planning coordinators representing approximately 95 percent of the Eastern Interconnection load. EIPC coordinates analysis of regional transmission plans to ensure their coordination and provides resources to conduct analysis of emerging issues impacting the transmission grid. EIPC work builds on, rather than replaces, existing regional and interregional transmission planning processes of participating planning authorities. EIPC's efforts are intended to inform regional planning processes.

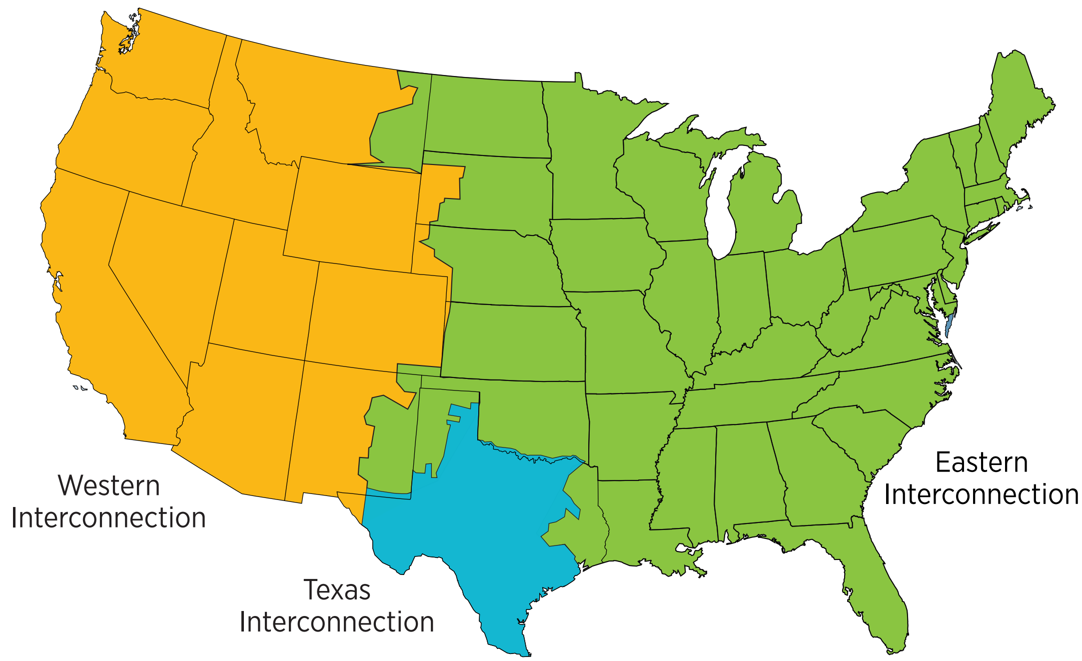
EIPC Activities

During 2020, EIPC continued to engage power system planning analysis activities including the following:

- The Frequency Response Working Group (FRWG) performed an evaluation of the Eastern Interconnection's ability to maintain frequency following a disturbance during a low-inertia period.
- The Transmission Analysis Working Group (TAWG) completed its analysis of a "roll-up integration model." This includes summer and winter cases that combine individual plans of each Planning Coordinator (PC).
- The Production Cost Task Force (PCTF) investigated a high-renewables future.

PJM expects many of these activities to continue in 2021, including the low-inertia frequency response study and the joint TAWG/PCTF high-renewables impact study.

Map 3.10: U.S. Interconnections



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3.6: Scenario Studies

PJM may conduct scenario studies in a given year in response to public policy and regulatory action, operational performance incidents, market economics, and/or technical industry trends and advancements. The studies, which are not required for reliability compliance, can provide valuable long-term expansion planning insights beyond conventional RTEP studies. In 2020, PJM investigated the incorporation of dynamic load models in stability studies and potential impacts of distributed energy resources on the transmission system.

Stability Studies Using Dynamic Load Models

Dynamic load modeling plays an important role in system stability, especially in system voltage recovery following a contingency event. The conventional static or complex load (CLOD) model has limitations regarding the modeling of single-phase air-conditional loads, motor stalls, protection trips or reconnections.

To consider more accurate dynamic behaviors of loads in stability studies, PJM is transitioning to adoption of state-of-the-art dynamic load models called composite load models (CMLD) in line with NERC's Load Modeling Task Force (LMTF) initiatives. Compared to the CLOD model, CMLD has the capability of modeling various three-phase motors (commercial or industrial) and single-phase motors (mainly residential air conditioners) as well as motor stalling, tripping or reclosing actions.

The scenario study investigated the impact of CMLD on PJM system stability for normal and stressed operating conditions under various NERC planning and extreme contingency events. Consistent with LMTF's phased approach on the implementation of CMLD in the Eastern Interconnection, the study applied the LMTF proposed CMLD data sets in three-phased stages to the entire PJM footprint. The study also compared the performance of CMLD and a CLOD model previously used in the PJM system. Furthermore, the study included a sensitivity analysis on key CMLD parameters. Future work of this challenging and ongoing task is also addressed, which includes benchmarking and validating the study findings against actual recorded events data from phasor measurement units (PMUs) or field measurements, and more contingency analysis on various system conditions.

Distributed Energy Resources Sensitivity Study

The current practice for handling distributed energy resources (DER), which includes implicitly modeling most DER as part of the load (netted with actual load at the bus), may lead to skewed study results. There can also be modeling inaccuracies related to the distribution of zonal-level load and behind-the-meter (BTM) solar forecasts. PJM has struggled with collecting DER data from distribution companies, as many of the companies fall below the NERC distribution provider threshold of 75 MW and, as a result, are not required to provide data under NERC jurisdiction. PJM also struggles with modeling DER for the following reasons:

- Current rules that allow for mingling of queue (wholesale) and local (retail) BTM DER
- Net metering that is not simply a reduction in load but an injection in front of the meter
- Distribution system changes that may alter the aggregation point of DER

Determining where to place DER in the planning models, in addition to any associated modeling complexity because of excessive detail, also poses a challenge.

To evaluate potential impacts of DER on its transmission system, PJM coordinated a cross-divisional sensitivity study for areas on the system where known BTM DER poses a current operational concern. PJM also analyzed a few extreme scenarios using the generator deliverability test. The intent of this analysis was to determine if solar DER, whether it be BTM or non-BTM, negatively impact PJM's transmission system in the planning models. Any potential violations identified in this study could provide valuable insight into system vulnerabilities. Recognizing that the full inclusion of explicit BTM DER into the planning models is a long-term goal, based on findings from the extreme scenario analysis, PJM could implement adjustments to the RTEP process to better account for DER in the future.

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3.7: Stage 1A ARR 10-Year Feasibility

Auction Revenue Rights (ARRs) are the mechanisms by which the proceeds from the annual FTR auction are allocated. ARRs entitle the holder to receive an allocation of the revenue from the annual FTR auction. Incremental ARRs (IARRs) are additional ARRs created by new transmission expansion projects. The PJM Operating Agreement, Schedule 1, Section 7.8 sets forth provisions permitting any party to request IARRs by agreeing to fund transmission expansions necessary to support the requested financial rights. Requests must specify a source, sink and megawatt amount. PJM conducts annual studies to determine if transmission system expansions are required to accommodate the requested IARRs so that all are simultaneously feasible for a 10-year period.

Scope

Each year, PJM conducts an analysis to test the transmission system's ability to support the simultaneous feasibility of all Stage 1A ARRs for base load plus the projected 10-year load growth. If needed, PJM will recommend expansion projects to be included in the RTEP with required in-service dates based on results of the 10-year analysis itself. As with all other RTEP expansion recommendations, those for ARRs will include the driver, cost, cost allocation and analysis of project benefits, provided that such projects will not otherwise be subject to a market efficiency cost/benefit analysis. Project costs are allocated across transmission zones based on each zone's Stage 1A eligible ARR flow contribution to the total Stage 1A-eligible ARR flow on the facility that limits feasibility.

Table 3.7: 2020/2021 Stage 1A ARR 10-Year Infeasible Facilities

Facility Name	Facility Type	Upgrade expected to Fix Infeasibility	Expected In-Service Date
Kilmer-Raritan River 230 kV Line	Internal	**PJM RTEP B3042:** Replace substation conductor at Raritan River 230 kV substation on the Kilmer line terminal.	2023

Results: 2020/2021 Stage 1A ARR 10-Year Analysis

During 2020, PJM staff completed a 10-year simultaneous feasibility analysis for 2020/2021 Stage 1A ARR selections. The power flow case used in the 10-year feasibility analysis is the same one used in the 2020/2021 annual ARR allocation, but without any modeled maintenance transmission outages. The results of the 10-year analysis identified a violation on a PJM internal facility. PJM determined that a transmission solution that will address the violation is already identified in the PJM regional planning process.

The facility along with the project expected to address the infeasibility is provided in **Table 3.7**. The violation is expected to be relieved by an already planned PJM RTEP baseline project. Since a plan has been established to address this violation, no further immediate action is necessary.

Section 4: Market Efficiency Analysis

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4.0: Scope

RTEP Process Context

PJM performs market efficiency analysis as part of the overall Regional Transmission Planning Process (RTEP) to accomplish the following objectives:

- Identify new transmission enhancements or expansions that could relieve transmission constraints that have an economic impact
- Review costs and benefits of economic-based transmission projects previously included in the RTEP to assure that they continue to be cost beneficial
- Determine which reliability-based transmission projects, if any, have an economic benefit if accelerated or modified
- Identify economic benefits associated with changes to reliability-based transmission projects already included in the RTEP that, when modified, would relieve one or more economic constraints. Such projects, originally identified to solve reliability criteria violations, may be designed in a more robust manner to provide economic benefit as well

PJM identifies the economic benefit of proposed transmission projects by conducting production cost simulations. These simulations show the extent to which congestion is mitigated by the project for specific study-year transmission and generation dispatch scenarios. Economic benefit is determined by comparing future-year simulations both with and without the proposed transmission enhancement. The metrics and methods used to determine economic benefit are described in:

- PJM Manual 14B, Section 2.6
- PJM Operating Agreement, Schedule 6, Section 1.5.7

Market Simulation Analysis

To conduct a market efficiency analysis, PJM uses a market simulation tool which models the market conditions and the hourly security-constrained commitment and dispatch of generation over a future annual period. Several basecases are developed. The primary difference between these cases is the transmission topology to which the simulation data corresponds:

- An "as-planned" basecase power flow models PJM Board-approved RTEP projects with required in-service date of June 1 of the five-year-out RTEP study year.
- A "project" case power flow that includes topology for specific projects under study.

PJM can determine a transmission project's economic impact by comparing the results of simulations with the same input assumptions and operating constraints but different transmission topologies. Combining this with benefit analysis allows PJM to evaluate if specific proposed transmission enhancements or expansions are economically beneficial.

Project Acceleration Analysis

Also, as part of the annual acceleration analysis, PJM creates an "as-is" basecase power flow that models a one-year-out study-year transmission topology. This allows PJM to perform the following:

- Identify economic benefits associated with acceleration or modification of reliability-based transmission projects already included in the RTEP
- Collectively value the congestion impact of approved RTEP portfolio of enhancements

Simulated transmission congestion results also provide important system information and trends to potential transmission developers and other PJM stakeholders.

24-Month Cycle

PJM's 2020/2021 24-month market efficiency timeline is shown in **Figure 4.1**. The 2020 market efficiency body of analysis is represented by the first year of the 24-month cycle and focused on the following:

- Creating and verifying basecase models and results
- Reviewing previously approved economic transmission projects
- Performing analysis to consider benefits of accelerating baseline projects not yet built
- Identifying the congestion drivers associated with the 2020/2021 RTEP long-term window

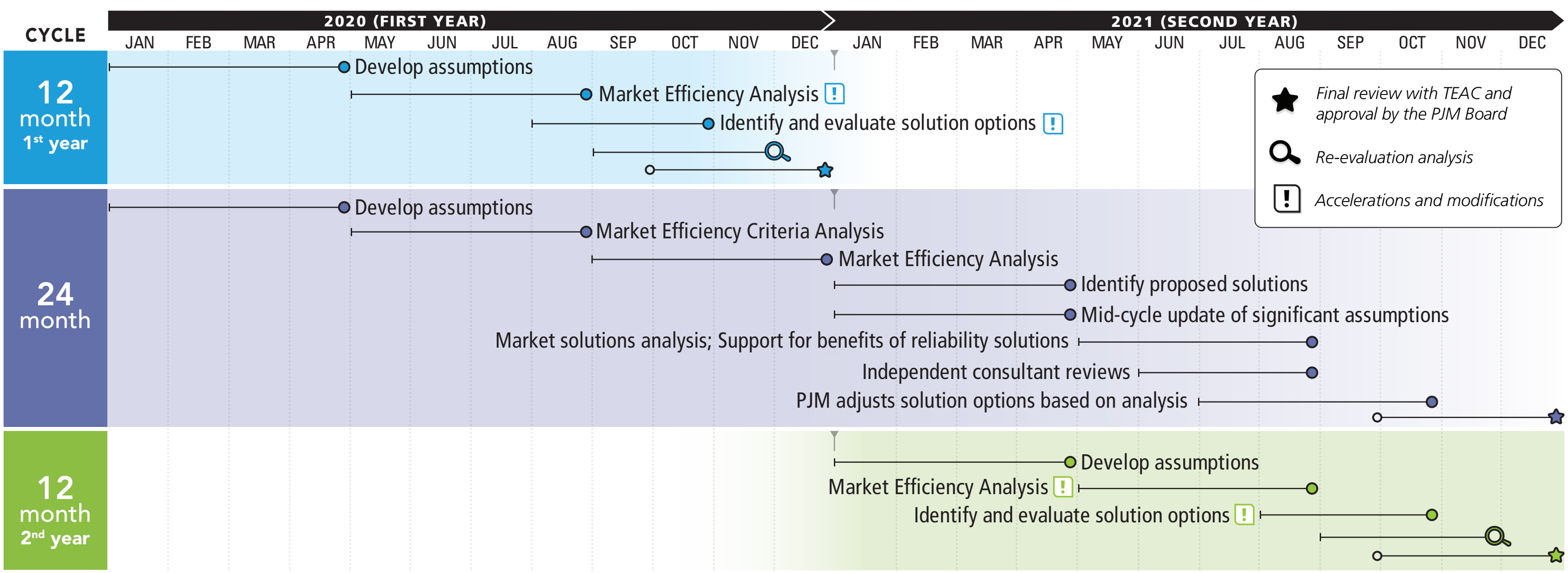
RTEP Project Acceleration Analysis: 2021 and 2025 Study Years

PJM compared simulations of near-term topologies with those of planned topologies to assess the individual and collective economic impacts of RTEP transmission enhancements not yet in service. PJM quantifies the transmission congestion reduction due to recently planned RTEP enhancements by comparing the simulation differences between the "as-is" basecase and the "as-planned" basecase for the 2021 and 2025 study years. Simulation comparisons help PJM to:

- Quantify the transmission congestion reduction from the collection of recently planned RTEP enhancements
- Reveal if specific, already-planned transmission enhancements may eliminate or relieve congestion so that the constraint is no longer an economic concern
- Identify if a project may provide benefits that would make it a candidate for acceleration or modification

For example, if a constraint causes significant congestion in the 2021 "as-is" simulation but not in the 2025 "as-planned" simulation, then a project that eliminates this congestion may be a candidate for acceleration. The acceleration cost is considered against the benefit of accelerating a project before any recommendation is made.

Figure 4.1: 2020/2021 Market Efficiency 24-Month Cycle



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Long-Term Window Simulations: 2021, 2025, 2028, 2031 Study Years

In order to quantify future longer-range transmission system market efficiency needs, PJM develops a simulation database for use as part of the long-term window study process. System modeling characteristics included in this 2020 database are broadly described in **Section 4.2**.

Market efficiency projects identified during the 2020/2021 RTEP long-term proposal window, scheduled for early 2021, will initially be evaluated using the cases developed during 2020. However, during the 2021 project evaluation phase, PJM will develop a 2021 mid-cycle update case that incorporates significant RTEP modeling changes. The mid-cycle update case includes potentially significant forecast changes in topology, generation, load and fuel costs. The purpose for the 2021 mid-cycle update case is to ensure that potential projects are evaluated using an updated forecast of future conditions.

Benefit-to-Cost Threshold Test

PJM calculates a benefit-to-cost threshold ratio to determine if there is market efficiency justification for a particular transmission enhancement. The benefit-to-cost ratio is calculated by comparing the net present value of annual benefits for a 15-year period starting with the RTEP year compared to the net present value of the project's revenue requirement for the same 15-year period. Market efficiency transmission proposals that meet or exceed a 1.25 benefit-to-cost ratio are further assessed to examine their economic, system reliability and constructability impacts. PJM's Operating Agreement requires that projects with a total cost exceeding $50 million undergo an independent third-party cost review.

For the majority of proposed projects, PJM determines market efficiency benefits based on energy market simulations. Transmission projects that have identified capacity market drivers may derive economic benefit determined through capacity market simulations.

PJM's market efficiency study process and benefit-to-cost ratio methodology are detailed in Manual 14B, Section 2, PJM Region Transmission Planning Process, which is available on PJM's website.

Energy Benefit – Regional Facilities

Energy benefit calculation for regional facilities is weighted as follows:

- 50 percent to change in system production cost
- 50 percent to change in net-load energy payments for zones with a decrease in net-load payments as a result of the proposed project

The change in system production cost is the change in system generation variable costs (i.e., fuel costs, variable operating and maintenance costs, and emissions costs) associated with total PJM energy production.

The change in net-load energy payment is the change in gross-load payment offset by the change in transmission rights credits. The net-load energy payment benefit is calculated only for zones in which the proposed project decreases the net-load payments. Zones for which the net-load payments increase because of the proposed project are excluded from the net-load energy payment benefit.

Energy Benefit – Lower-Voltage Facilities

Energy benefit calculation for lower-voltage facilities is weighted 100 percent to zones with a decrease in net-load payments as a result of the proposed project. The change in net-load energy payment is the change in gross-load payment offset by the change in transmission rights credits. The net-load payment benefit is only calculated for zones in which the proposed project decreases the net-load payments. Zones for which the net-load payments increase because of the proposed project are excluded from the net-load energy payment benefit.

Capacity Benefit – Regional Facilities

PJM's annual capacity benefit calculation for regional facilities is weighted as follows:

- 50 percent to change in total system capacity cost
- 50 percent to change in net-load capacity payments for zones with a decrease in net-load capacity payments as a result of the proposed project

The change in net-load capacity payment is the change in gross capacity payment offset by the change in capacity transfer rights.

Capacity Benefit – Lower-Voltage Facilities

PJM's annual capacity benefit calculation for lower-voltage facilities is weighted 100 percent to zones with a decrease in net-load capacity payments as a result of the proposed project. The change in net-load capacity payment is the change in gross capacity payment offset by the change in capacity transfer rights.

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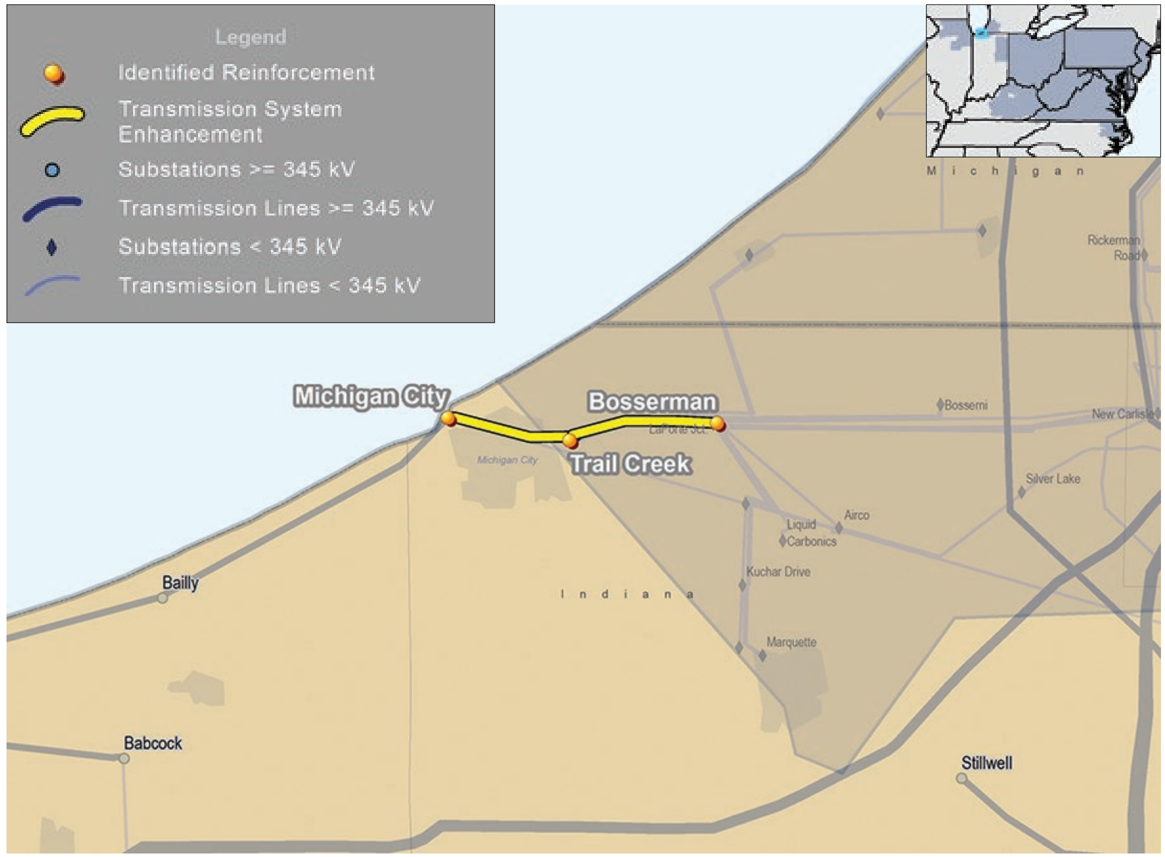
2018/2019 RTEP Long-Term Proposal Window – Interregional Market Efficiency

On Dec. 3, 2019, the PJM Board of Managers conditionally approved the PJM-MISO interregional baseline project B3142, the rebuild of the Bosserman-Trail Creek-Michigan City 138 kV line, shown in **Map 4.1,** subject to MISO Board approval. The project is the first interregional proposal approved through PJM's RTEP long-term proposal window. The Bosserman-Trail Creek-Michigan City 138 kV line was identified as an interregional targeted congestion facility. Simulations performed in advance of the 2018/2019 RTEP long-term proposal window identified over $1.4 million in market congestion on this facility based on 2023 input assumptions and simulation results.

Since the PJM Board's conditional approval, FERC approved MISO's cost allocation compliance filing on July 28, 2020, allowing MISO's Board to approve the project on Sept. 17, 2020. Subsequently, at its December 2020 meeting, the PJM Board confirmed its approval to be included in the RTEP. The estimated cost for this project is $24.69 million, of which $22 million is allocated to PJM, with a required and projected in-service date of January 2023.

Map 4.1: Baseline Project B3142: Bosserman-Trail Creek-Michigan City 138 kV Project



4.1: Input Parameters – 2020 Basecase

Overview

PJM licenses a commercially available database containing the necessary elements to perform detailed PJM energy market simulations. This database is periodically updated permitting up-to-date representation of the Eastern Interconnection and, in particular, PJM. The Transmission Expansion Advisory Committee (TEAC) reviews the key analysis input parameters, shown in **Figure 4.2**. These parameters include fuel costs, emissions costs, load forecasts, demand resource projections, generation projections, expected future transmission topology, and several financial valuation assumptions.

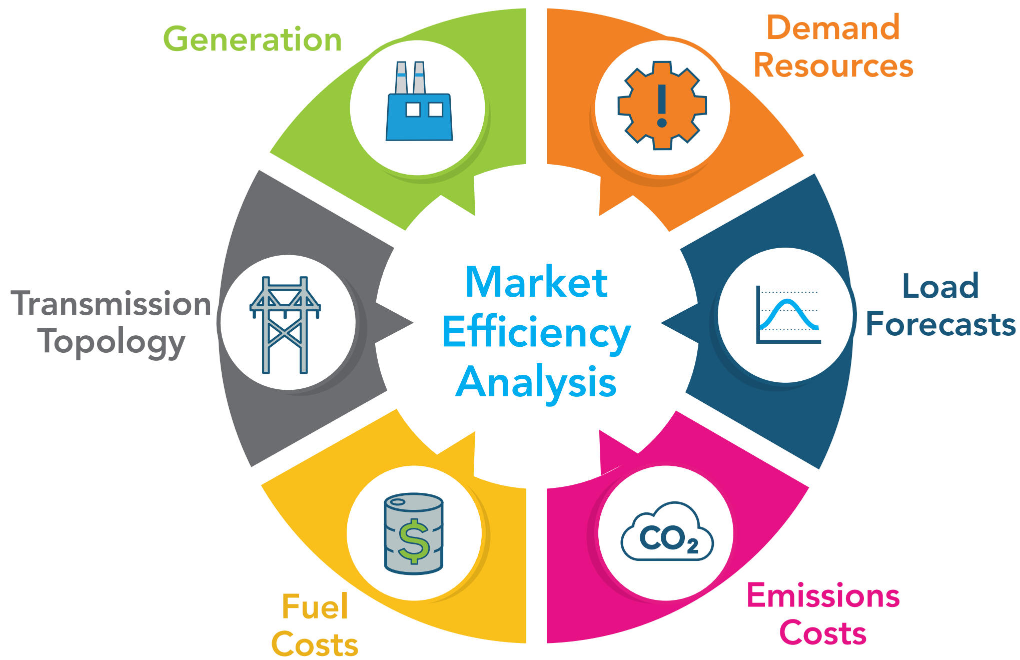
Transmission Topology

Market efficiency power flow models were developed in 2020 to represent:

- The 2021 "as-is" transmission system topology
- The expected 2025 five-year-out system topology

PJM derived the "as-is" system topology from its review of the Eastern Interconnection Reliability Assessment Group's Series 2020 Multiregional Modeling Working Group (MMWG) 2021 summer peak case. It included transmission enhancements expected to be in service by the summer of 2021. PJM derived system topologies for 2025 from the 2025 RTEP case and included significant RTEP projects approved during the 2020 RTEP cycle.

Figure 4.2: Market Efficiency Analysis Parameters



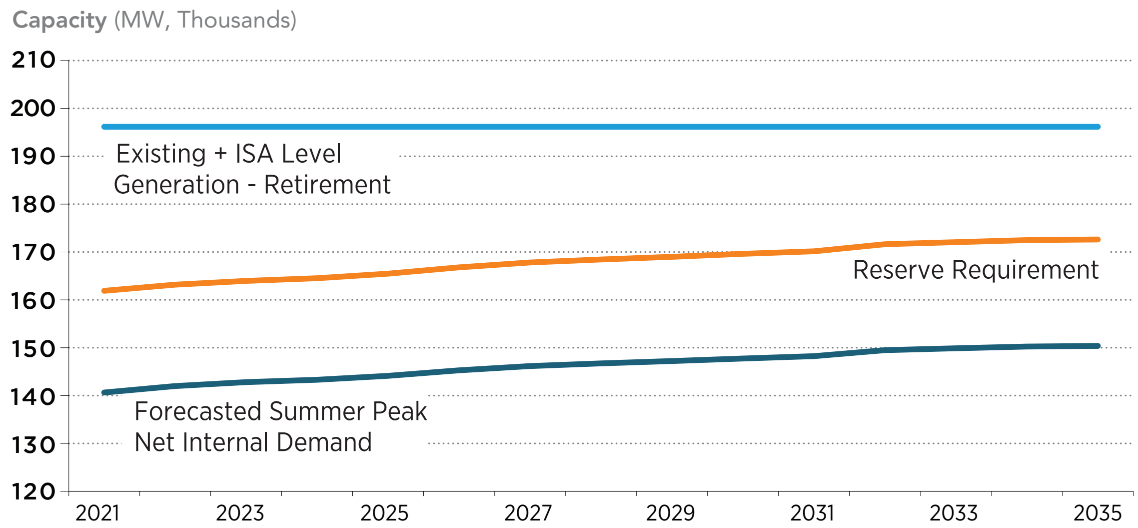
Monitored Constraints

Specific thermal and reactive interface transmission constraints are modeled for each base topology. Monitored thermal constraints are based on actual PJM market activity, historical PJM congestion events, PJM planning studies or studies compiled by NERC. PJM reactive interface limits are modeled as thermal values that correlate to power flows beyond which voltage violations may occur. The modeled interface limits are based on voltage stability analysis and a review of historical values. Modeled values of future-year reactive interface limits incorporate the impact of approved RTEP enhancements on the reactive interfaces.

Generation Modeled

Market efficiency basecase simulations model existing in-service generation plus actively queued generation with at least an executed Interconnection Service Agreement (ISA), less planned generator deactivations that have given formal notification. The modeled generation provides enough capacity to meet PJM's installed reserve requirement through all study years, as shown in **Figure 4.3**.

Figure 4.3: PJM Market Efficiency Reserve Margin



NOTE:

Figure 4.3: Generation includes existing and projected PJM internal capacity resources. Solar and wind resource capacity are modeled at 38% and 13% of maximum capability, respectively. Model informed by 2025 machines list.

Fuel Price Assumptions

PJM uses a commercially available database tool that includes generator fuel price forecasts. Forecasts for short-term gas and oil prices are derived from New York Mercantile Exchange future prices. Long-term forecasts for gas and oil are obtained from commercially available databases, as are all coal price forecasts. Vendor-provided basis adders are applied as well to account for commodity transportation cost to each PJM zone. The fuel price forecasts used in PJM's 2020 market efficiency analysis are represented in **Figure 4.4**.

Load and Energy Forecasts

PJM's load forecast provides the transmission zone peak load and energy data modeled in market efficiency simulations. **Table 4.1** summarizes the PJM peak load and energy values used in the 2020 market efficiency cases.

Demand Resources

The amount of demand resource modeled in each transmission zone is based on the 2020 PJM Load Forecast Report. **Table 4.2** summarizes PJM demand resource totals by year.

Figure 4.4: Fuel Price Assumptions

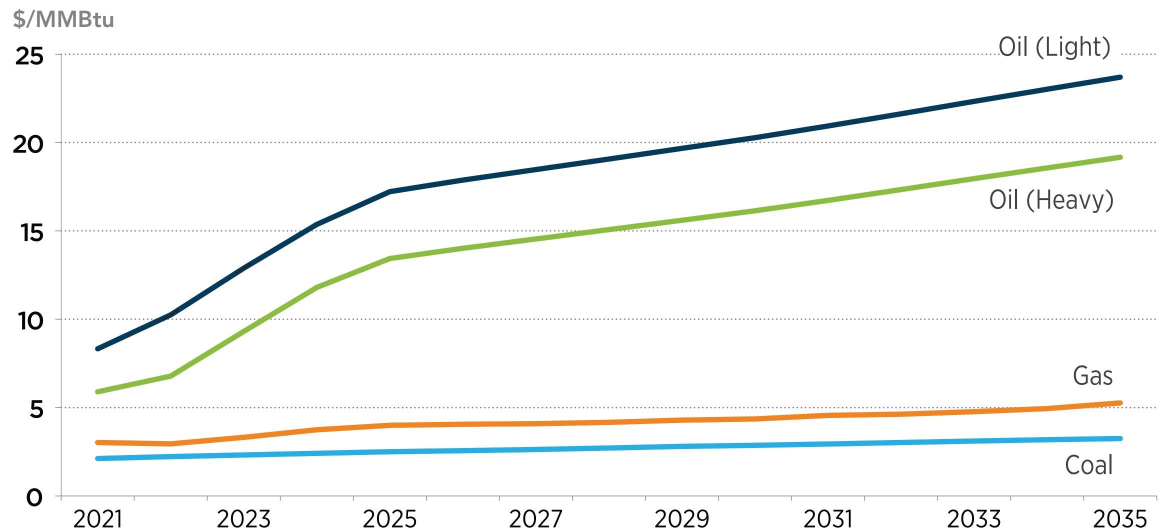


Table 4.1: 2020 PJM Peak Load and Energy Forecast

Load	2021	2025	2028	2031	2035
Peak (MW)	147,064	153,315	156,014	157,637	159,868
Energy (GWh)	771,639	817,966	834,225	843,471	857,016

Note: 1. Peak and energy values for 2025 onward are from the 2020 PJM Load Forecast Report Table B-1 and Table E-1, respectively.
2. Peak and energy values for 2021 are from the July 2020 Forecast Update.

Table 4.2: Demand Resource Forecast

Demand Resource	2021	2025	2028	2031	2035
Demand Resource (MW)	8,955	9,172	9,293	9,405	9,494

Note: Values are from the 2020 PJM Load Forecast Report Table B-7.

Emission Allowance Price Assumptions

PJM currently models three major effluents – SO_2, NO_x and CO_2 – within its market efficiency simulations. Effluents (by trading program) are assigned to generators based on generator location, and release rates assigned based on generator characteristics and the fuel forecast to be used. SO_2 and NO_x emission price forecasts reflect implementation of the Cross-State Air Pollution Rule (CSAPR) and are shown in **Figure 4.5** and **Figure 4.6**, respectively.

Figure 4.5: SO_2 Emission Price Assumption

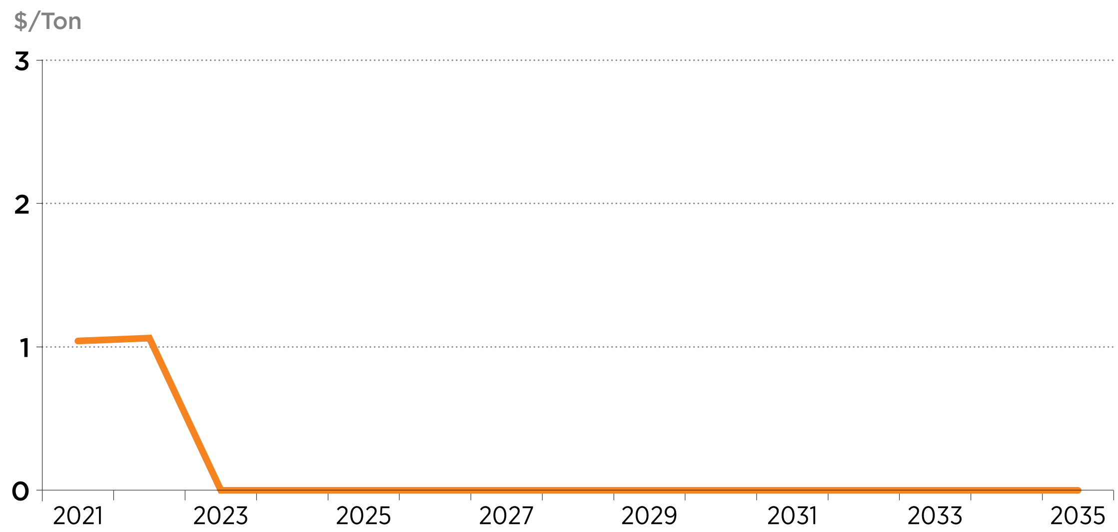
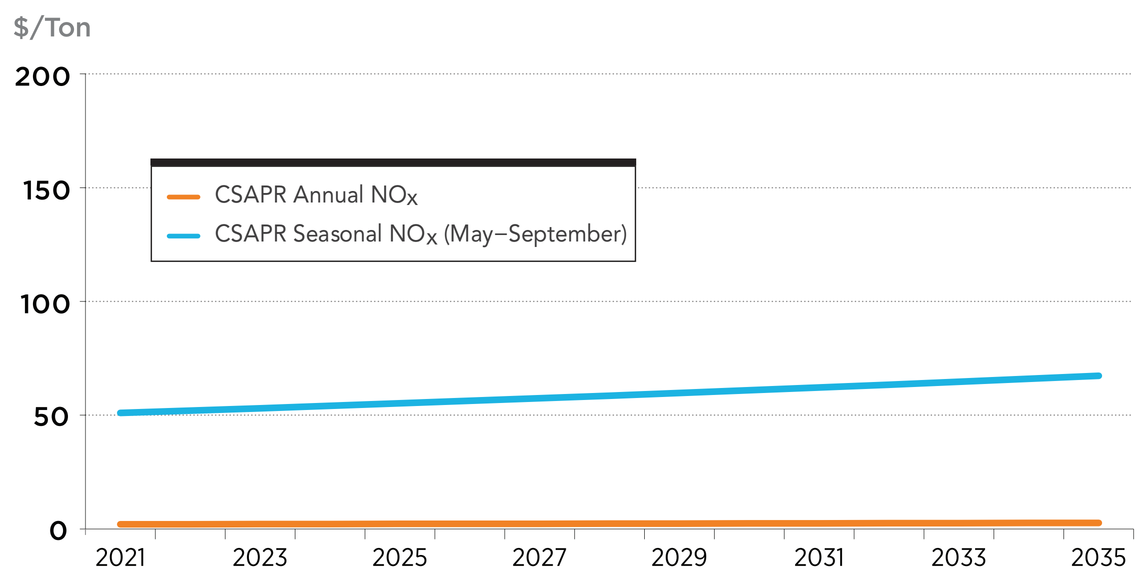


Figure 4.6: NO_x Emission Price Assumption

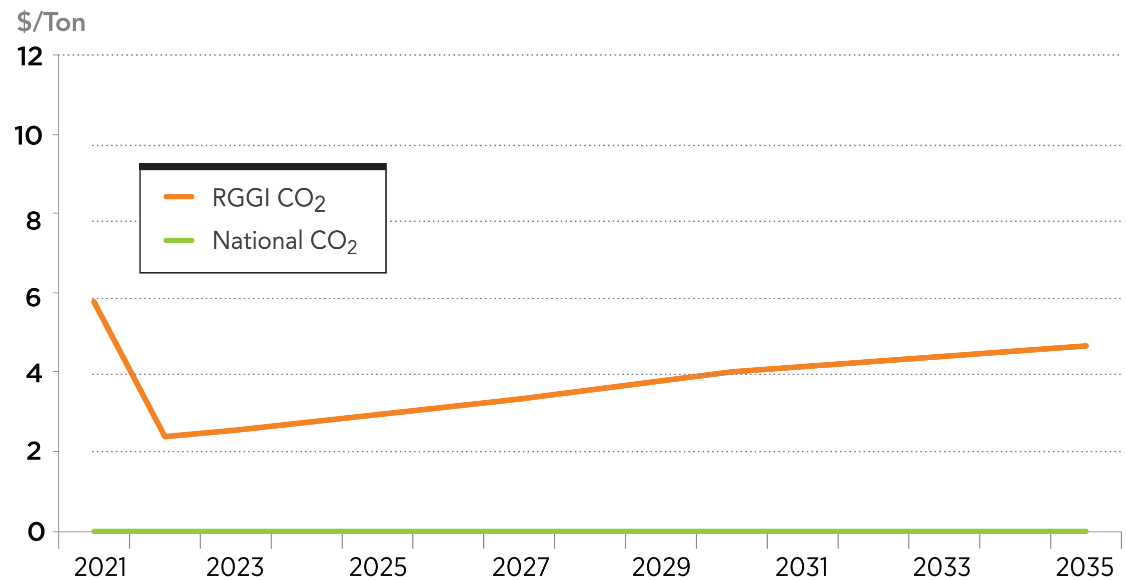


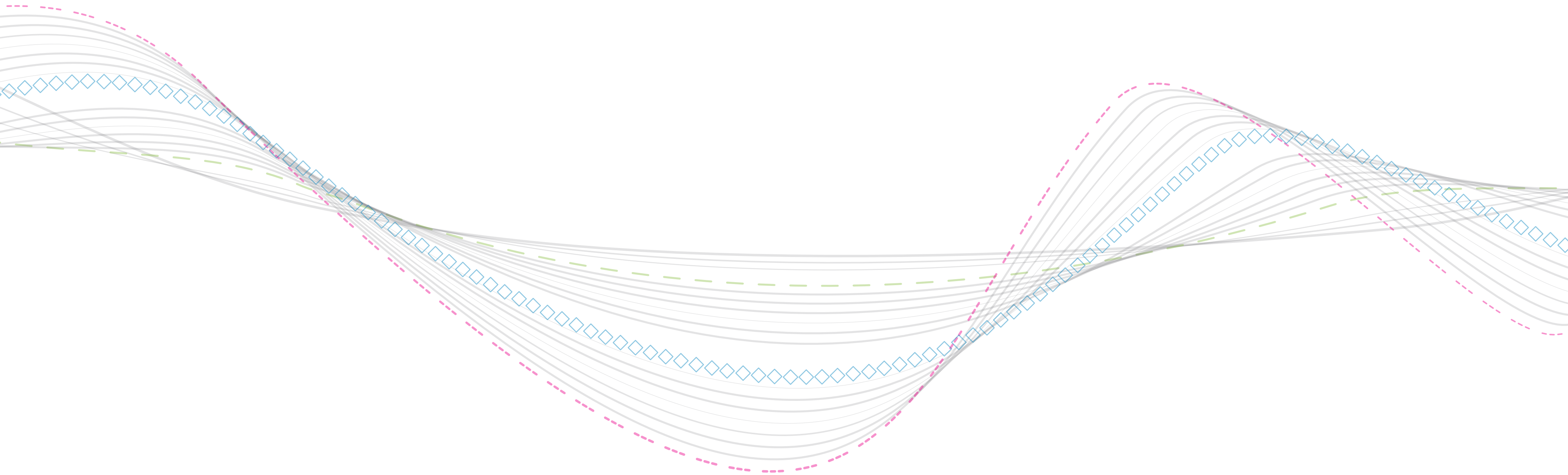
PJM unit CO_2 emissions use a CO_2 emission forecast based on national and regional legislative proposals. PJM units in Maryland, Delaware, New Jersey and Virginia are modeled as part of the Regional Greenhouse Gas Initiative (RGGI) program. The base emission price assumption for both the national CO_2 and RGGI CO_2 program is shown in **Figure 4.7**.

Carrying Charge Rate and Discount Rate

The evaluation of proposed market efficiency projects requires a benefit-to-cost analysis. As part of this evaluation, the present value of annual benefits projected for a 15-year period starting with the RTEP year, is compared to the present value of the annual cost for the same period. If the benefit-to-cost ratio exceeds a threshold of at least 1.25:1, then the project can be recommended for inclusion in the PJM RTEP. The annual cost of the upgrade will be based on the total capital cost of the project, multiplied by a levelized annual carrying charge rate. A discount rate will be used to determine the present value of the project's annual costs and annual benefits. The annual carrying charge rate and discount rate are developed using information contained in the transmission owners' formula rate sheets and incorporated in the Transmission Cost Information Center (TCIC) workbook available on PJM's website. The current annual carrying charge rate and discount rate for this year's analysis are 11.82 percent and 7.37 percent, respectively.

Figure 4.7: CO_2 Emission Price Assumption





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4.2: Study Results From 2020 Analysis

Acceleration Results From 2020 Analysis

PJM's 2020 cycle of analysis included near-term simulations for study years 2021 and 2025. These simulations identified collective and constraint-specific transmission system congestion because of the impacts of previously approved RTEP projects not yet in service. PJM conducted the simulations under two different transmission topologies:

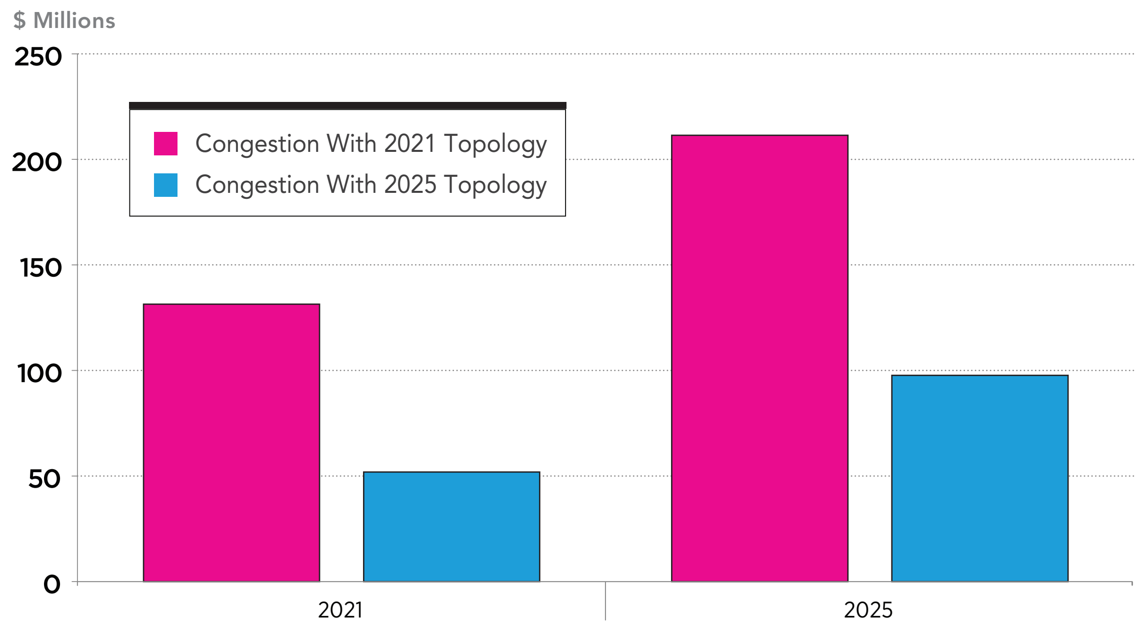
1. 2021 "as-is" PJM transmission system topology
2. 2025 "as-planned" RTEP PJM transmission system topology

By comparing results of multiple simulations with the same fundamental supply, demand and operating constraints but with differing transmission topologies, the economic value of a transmission enhancement can be determined. This technique allows PJM to perform the following:

1. Value collectively the congestion benefits of approved RTEP upgrades
2. Evaluate the congestion benefits of accelerating or modifying specific RTEP projects

PJM congestion costs from market simulations for study years 2021 and 2025 are shown in **Figure 4.8**. There were annual congestion cost reductions of more than $79 million (60 percent) for 2021 and more than $113 million (54 percent) for 2025 using the 2025 RTEP topology. RTEP enhancements that are approved but not yet in service account for the reduction in congestion.

Figure 4.8: 2020 Analysis of Simulated PJM Congestion Costs – 2021, 2025



Project-Specific Acceleration Analysis

PJM identified and evaluated specific RTEP enhancements driving congestion reductions identified in acceleration simulations. The majority of identified baseline reliability enhancements, viewed within the context of the short-term analysis, will not be recommended for acceleration. These projects provide neither significant congestion benefits in the acceleration analysis, nor are they practical to accelerate, because they have a near-term in-service date or because they are large projects.

Baseline project B3157, a $0.23 million upgrade of substation equipment at APS Messick Road and Morgan 138 kV substations, shows significant congestion benefits if accelerated before year 2024. Project B3157 was selected for an accelerated 2021 in-service date with no additional cost as a result of the change.

Long-Term Simulation Results: 2021, 2025, 2028 and 2031 Study Years

To identify and quantify long-term transmission system congestion, market simulations were conducted for study years 2021, 2025, 2028 and 2031. These simulations used the 2025 RTEP "as-planned" transmission system topology and included RTEP projects approved through the 2020 RTEP cycle.

Overall, congestion levels in the 2020 cycle of analyses remain low compared to previous RTEP cycles. This is, in part, because of:

- Low gas-price assumptions coupled with generation portfolio shifts that include increased high-efficiency, gas-fired generation and renewable resources
- Continued high generation reserves
- Continued lower load forecast levels compared to previous forecasts
- RTEP transmission enhancements, which are improving or eliminating potential congestion-causing constraints

PJM will solicit stakeholder proposals for market efficiency projects as part of an RTEP proposal window focusing on congestion identified in the 2020 long-term analysis.

PJM's competitive planning process is detailed in Manual 14F, which is available on PJM's website. Preliminary congestion drivers are shown in **Table 4.3**. These include facilities and their simulated congestion levels. They are part of PJM's solicitation of proposals for the 2020/2021 RTEP long-term proposal window scheduled for early 2021.

Table 4.3: Preliminary 2020/2021 Long-Term Window Congestion Drivers

			Market Efficiency Basecase				
			Annual Congestion ($M)		Hours Binding		
			Simulated Year				
Constraint	From Area	To Area	2025	2028	2025	2028	Comment
Kammer North to Natrium 138 kV	AEP	AEP	$2.54	$12.22	105	249	Internal Flowgate
Maliszewski Transformer 765/138 kV	AEP	AEP	$4.02	$5.64	29	40	Internal Flowgate
Muskingum River to Beverly 345 kV	AEP	AEP	$1.08	$2.19	112	184	Internal Flowgate
Cherry Run to Morgan 138 kV	AP	AP	$3.46	$4.12	257	288	Internal Flowgate
Gore to Stonewall 138 kV	AP	AP	$25.07	$35.00	577	753	Internal Flowgate
Junction to French's Mill 138 kV	AP	AP	$4.97	$5.89	255	257	Internal Flowgate
Yukon to AA2-161 Tap 138 kV	AP	AP	$4.31	$5.39	1743	2043	Internal Flowgate
Charlottesville to Proffit Rd Del Pt 230 kV	DOM	DOM	$2.80	$2.92	116	96	Internal Flowgate
Plymouth Meeting to Whitpain 230 kV	PECO	PECO	$6.17	$6.40	150	145	Internal Flowgate
Cumberland to Juniata 230 kV	PLGRP	PLGRP	$5.77	$6.39	151	158	Internal Flowgate
Harwood to Susquehanna 230 kV	PLGRP	PLGRP	$20.39	$16.47	1145	878	Internal Flowgate
Duff to Francisco 345 kV	DUK-IN	DUK-IN	$0.86	$3.71	74	118	M2M
Gibson to Francisco 345 kV	DUK-IN	DUK-IN	$4.18	$3.59	195	200	M2M
Quad Cities to Rock Creek 345 kV	ComEd	ALTW	$6.35	$9.01	148	172	M2M

Note: Cumberland-Juniata and Harwood-Susquehanna congestion drivers may be impacted by DLR projects.

NOTE:

Table 4.3: PJM's 120 day 2020/2021 RTEP long-term proposal window opened on Jan. 11, 2021. Updated congestion drivers presented in early 2021 are available at the following: TEAC Market Efficiency Update.

NOTE:

Dynamic line rating (DLR) technology provides a means for determining more precise line ratings based on actual environmental conditions. DLR technology does not modify the physical characteristics of a transmission line. Please see **Section 1.3.7** for additional information concerning DLR.

Table 4.4: 2020 Analysis: Re-evaluation of Projects under $20 Million – Updated Cost

Project ID	Baseline ID	Type	Area	Constraint	Benefit-to-Cost Ratio	Projected In-Service Date	2020 Re-Evaluation Benefit-to-Cost Ratio
201415_1-4I	B2697.1-2	Upgrade	AEP	Fieldale to Thorton 138 kV	101.19	B2697.1: 10/01/2020 B2697.2: 06/03/2021	28.11
201617_1A_RPM_DEOK	B2976	Upgrade	DEO&K	Tanners Creek to Dearborn 345 kV	151.61	3/4/2021	151.61
201819_HL_622	B3145	Upgrade	METED	Hunterstown to Lincoln 115 kV	59.45	6/1/2023	59.45

2020 Re-Evaluation of Previously Approved Market Efficiency Projects

PJM's 2020 analysis included a re-evaluation of approved market efficiency projects from previous long-term window processes. Changes to the criteria used for re-evaluation were implemented in 2019 through the Market Efficiency Process Enhancement Task Force (MEPETF) – discussed in **Section 4.4**. The new re-evaluation criteria include the following:

- Projects that are under construction or that have a Certificate of Public Convenience and Necessity (CPCN), are no longer required to be re-evaluated
- Projects not under construction or without a CPCN, with capital costs less than $20 million, will have projected costs updated and, will be re-evaluated using previously determined benefits
- Projects not under construction or without a CPCN, with capital costs greater than $20 million, will have projected costs updated and benefits re-evaluated

Three previously approved projects with projected capital costs less than $20 million have yet to begin construction and are shown in **Table 4.4.** Each maintains a benefit-to-cost ratio greater than 1.25 using the original project benefit with an updated capital cost estimate.

One previously approved project with capital costs greater than $20 million awaits CPCN action by the Pennsylvania Public Utility Commission. This project, identified as Project 9A, which includes RTEP baseline projects B2742 and B2752, is shown on **Map 4.2**. Project 9A, includes system enhancements in Pennsylvania and Maryland. The Maryland portion of the project was granted a CPCN in June 2020.

This project is included as part of the 2020 market efficiency basecase discussed earlier in **Section 4.2**. PJM recalculated economic value through simulations in which the project is removed from the model to determine the benefit that retaining it otherwise still provides. A benefit-to-cost ratio was derived by comparing the base simulation to the individual cases that did not include the project, while adhering to the methods described in **Section 4.0.**

Market efficiency analysis identified interaction between three projects providing congestion relief along the South-Central Pennsylvania and Northern Maryland border regions. The Hunterstown-Lincoln Project (B3145), Project 9A (B2742 and B2752) and Project 5E (B2992) each and collectively support economic transfers between these regions. Additionally, through siting proceedings in Pennsylvania and Maryland, several parties have filed a settlement that offers an alternative configuration of the eastern portion of Project 9A. More information about these topics can be found in the [December 2019 Baseline Market Efficiency Recommendations] document.

Table 4.5 shows the 2020 re-evaluation results for Project 9A. The project maintains a benefit-to-cost ratio greater than 1.25 either individually or in combination with other important regional projects when sunk costs are excluded from the project costs.

Additionally, PJM analysis indicates that Project 9A supports benefits beyond what is measured by a benefit-to-cost ratio. These benefits include the following:

- Supports state coal retirement legislation
- Enables additional access to Pennsylvania Marcellus Shale
- May provide support for state renewable energy policies; potential increased access to offshore wind power
- Enhances states' access to external generation to support RGGI participation
- Enhances reliability

Map 4.2: Project 9A – RTEP Baseline Projects B2743 and B2752

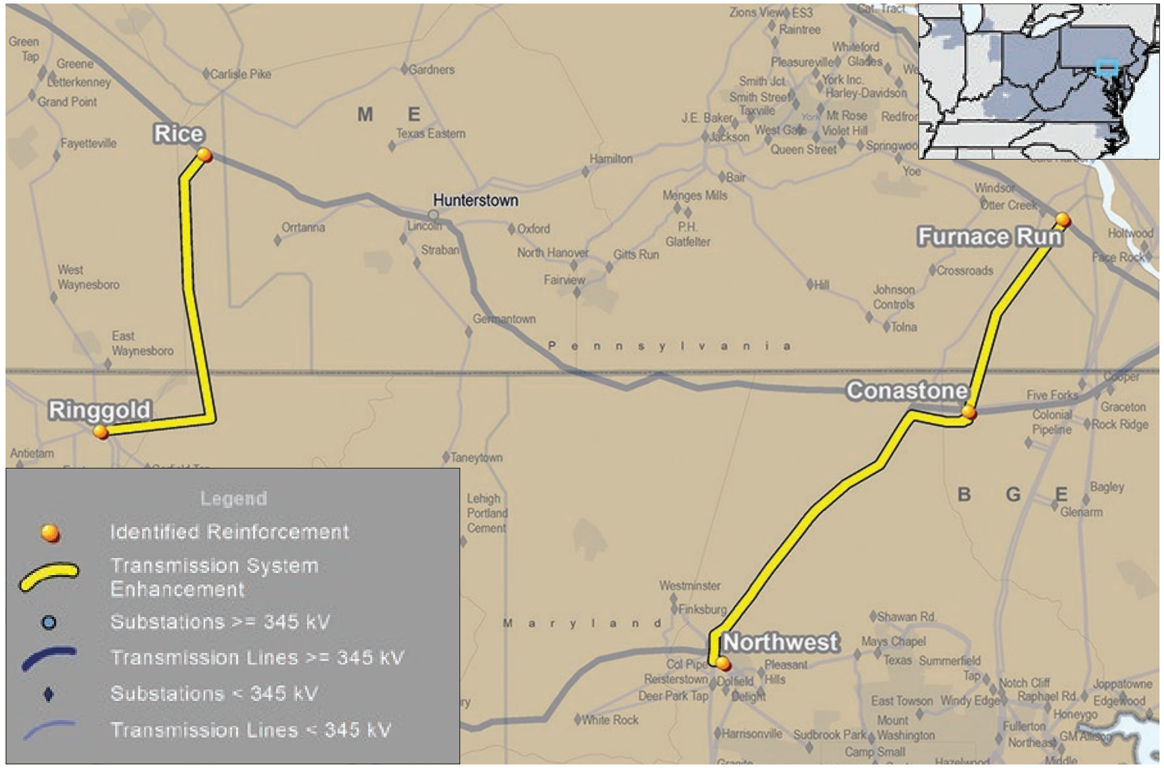


Table 4.5: Re-Evaluation of Projects Greater Than $20 Million – Updated Benefit-to-Cost Ratio, Project 9A

Re-Evaluation	Benefit-to-Cost Ratio Dec. 2020 (Sunk Costs Excluded)	Notes		
		B/C Ratio (In-Service Costs)	Cost	
			In-Service	Sunk
Project 9A (5E + H-L in Basecase)	1.71	1.22	$423.66	$121.03
Project 9A + H-L (5E in Basecase)	3.87	2.78	$430.87	$121.03
Alt. Project 9A (5E + H-L in Basecase)	1.29	1.00	$534.87	$121.03
Alt. Project 9A + H-L (5E in Basecase)	2.87	2.23	$542.08	$121.03

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

4.3: 2019/2020 Market Efficiency Process Enhancements

The Market Efficiency Process Enhancement Task Force (MEPETF) was chartered in January 2018, under the auspices of the PJM Planning Committee. The mission of the task force was to review, evaluate and recommend necessary changes to market efficiency process elements, including the following:

- Benefit-to-cost calculation
- Facilities Study Agreement (FSA) modeling
- Market efficiency window
- Interregional Market Efficiency Project (IMEP) selection process
- Market efficiency re-evaluation process
- Regional Targeted Market Efficiency Project (TMEP)
- Market efficiency mid-cycle assumption update

To date, the task force has completed three phases of work and has now concluded its activity.

Phase 1

Phase 1 revisions addressed the following:

- Generation assumptions that go into PJM's market efficiency analysis
- Time period over which the benefit-to-cost analysis is performed

The first set of revisions changed the default treatment of generation with executed FSAs or executed ISAs under suspension. It excluded those generation projects as a default in conducting market efficiency analysis. The second set of revisions limited project evaluation to a 15-year period that begins with the RTEP year. In February 2019, FERC accepted PJM's Operating Agreement revisions from these MEPETF Phase 1 efforts.

Phase 2

As a result of the task force efforts completed during Phase 2, PJM filed revisions to the Operating Agreement, Schedule 6 and Section 1.5.7 (f). This section describes the criteria for market efficiency project re-evaluation. The revisions included specifying a time after which PJM would no longer be required to conduct an annual re-evaluation of previously approved market efficiency projects. The new re-evaluation criteria now include the following:

- Projects where construction activities have commenced at the project site, or that have a Certificate of Public Convenience and Necessity (CPCN), are no longer required to be re-evaluated
- Projects not under construction, or without a CPCN, with capital costs less than $20 million, will have projected costs updated and will be re-evaluated using previously determined benefits
- Projects not under construction or without a CPCN, with capital costs greater than $20 million, will have projected costs updated and benefits re-evaluated.

On Aug. 22, 2019, FERC accepted PJM's proposed Operating Agreement revisions from MEPETF Phase 2 efforts.

Phase 3

In June 2019, the PJM Planning Committee endorsed amendments to the task force charter to add a third phase. Key areas of review included:

- Concerns with benefit calculations using summation of energy and capacity benefits
- Regional Targeted Market Efficiency Projects (RTMEP)
- Two specific concerns raised by stakeholders on the benefit-to-cost calculation

At the end of Phase 3, PJM filed Operating Agreement and Tariff revisions that clarify PJM's consideration of capacity constraints in PJM's overall market efficiency analysis.

Separation of energy market and capacity market congestion drivers will allow for distinct proposal windows to address the different type of constraints, if appropriate.

On December 18, 2020, FERC accepted PJM's proposed Operating Agreement revisions from MEPETF Phase 3 efforts.

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Section 5: Facilitating Interconnection

PJM | DE | DC | IL | IN | KY | MD | MI | NJ | NC | OH | PA | TN | VA | WV

5.0: New Services Queue Requests

5.0.1 — Interconnection Activity

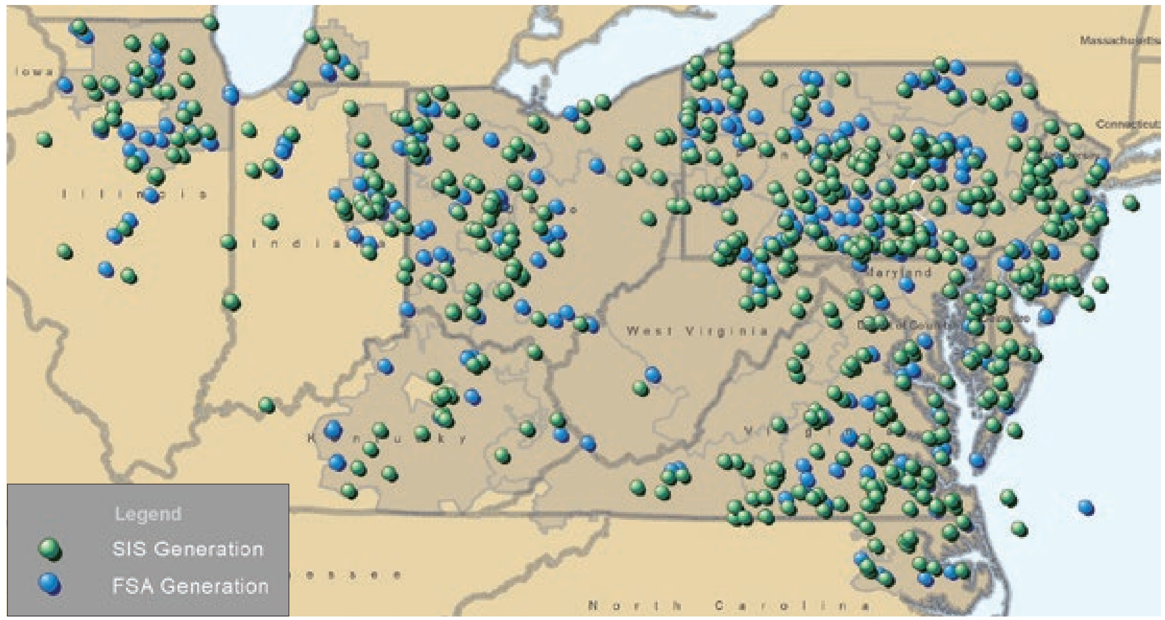
The generation interconnection process has three study phases – feasibility, system impact and facilities studies – to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets.

Generation Queue Activity

PJM markets have attracted generation proposals totaling 502,706 MW, as shown in **Table 5.1**. Over 83,865 MW of interconnection requests were actively under study during 2020. PJM analyzed and issued study reports for 751 feasibility studies and 662 system impact studies, as shown on **Map 5.1**. This unprecedented queue volume, as of Dec. 31, 2020, was composed of 88 percent renewable fuel types – notably, solar – as described later in this section.

Over 21,546 MW of new generation was under construction as of Dec. 31, 2020, across all fuel types. While withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, regulatory, industry, economic and other competitive factors. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities.

Map 5.1: Feasibility and System Impact Studies Performed in 2020



In 2020 PJM received **1,028 new service requests** representing 70,375 MW (energy) of generation and 44,179 MW of CIRs

During calendar year 2020, PJM issues a total of **1,424 Feasibility/Impact/ Facilities studies**

Queue Progression History

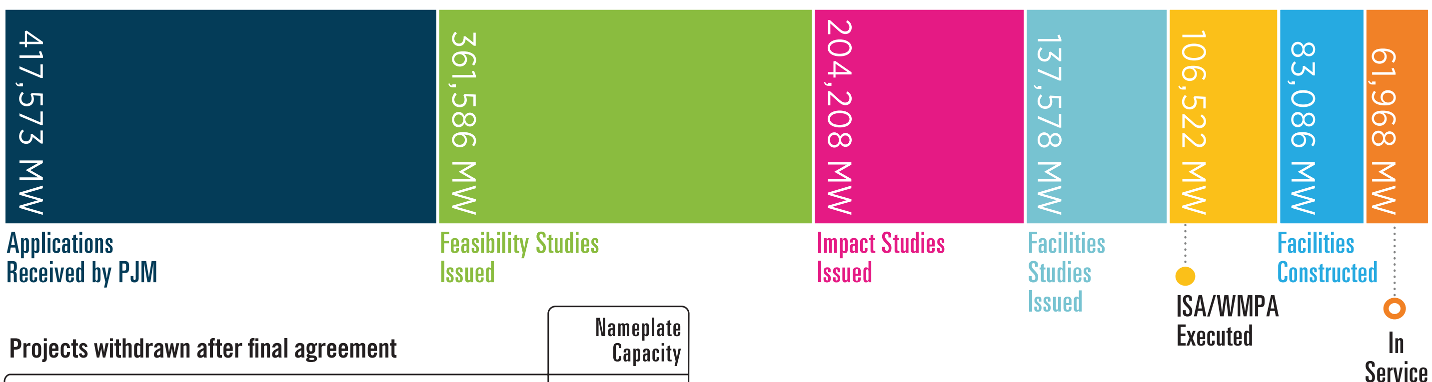
PJM reviews generation queue progression annually to understand overall developer trends more fully and their impact on PJM's interconnection process. **Figure 5.1** shows that for generation submitted in Queue A (1999) through Dec. 31, 2020, only 61,968 MW – 15 percent – reached commercial operation. Note that **Figure 5.1** reflects requested capacity interconnection rights which are lower than nameplate capacity given the intermittent operational nature of wind- and solar-powered plants.

Following execution of an interconnection service agreement (ISA) or wholesale market participant agreement (WMPA), 22,442 MW of capacity with ISAs and 1,107 MW of capacity with WMPAs withdrew from PJM's interconnection process. Overall, 23 percent of projects that requested uprates to existing capacity reached commercial operation. Only 15 percent of new generator requests, by megawatt, reached commercial operation.

Table 5.1: Queued Study Requests

	Projects	Energy (MW)	Capacity (MW)
Active	1,553	147,122	83,865
In Service	927	72,729	60,687
Under Construction	346	27,946	21,546
Withdrawn	3,173	429,133	336,609
Grand Total	**5,999**	**676,931**	**502,706**

Figure 5.1: Queued Generation Progression – Requested Capacity Rights (Dec. 31, 2020)



Projects withdrawn after final agreement

			Nameplate Capacity
177	Interconnection Service Agreements	**22,442** MW	30,294 MW
291	Wholesale Market Participation Agreements	**1,107** MW	2,293 MW

Percentage of planned capacity and projects that have reached commercial operation	15% Requested capacity megawatts	23% Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2020.

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5.0.2 — Interconnection Reliability

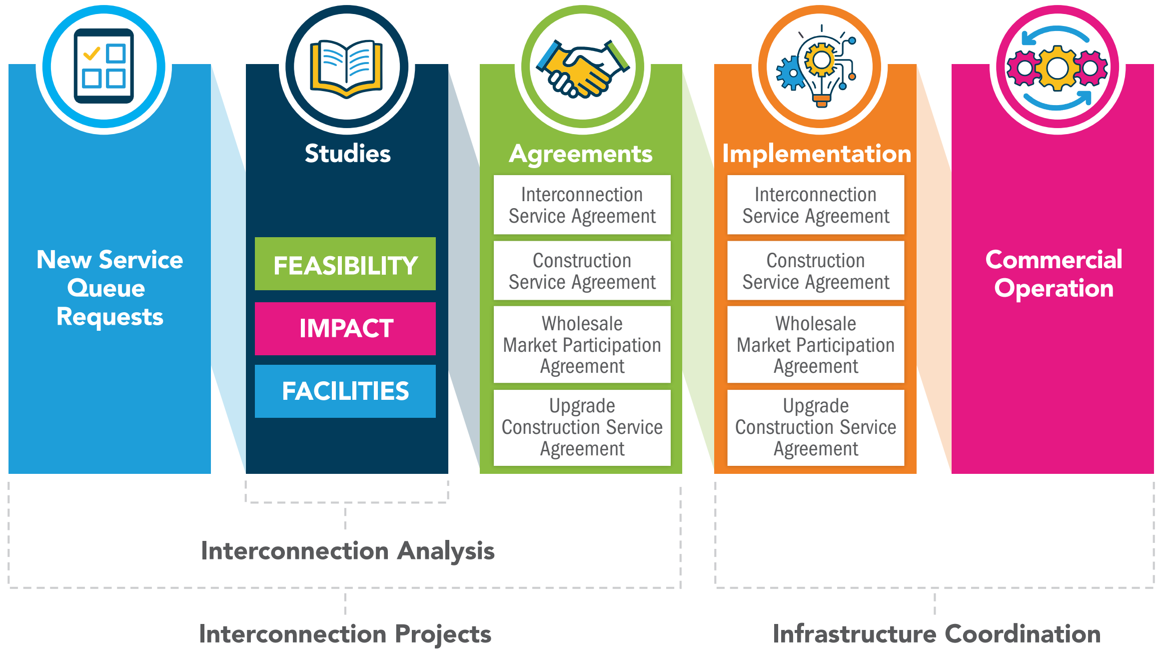
A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. The PJM Board has approved network facility reinforcements totaling $6.4 billion. The PJM Board approved 95 new network system enhancements totaling over $100 million in 2020 alone. As described in **Section 1.2**, PJM tests for compliance with NERC and regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies system conditions that sufficiently stress the transmission system as part of evaluating criteria compliance.

PJM's generator deliverability test prescribes the test conditions for ensuring that sufficient transmission capability exists to deliver generating capacity reliably from a defined generator or area to the rest of PJM load. In addition to generator interconnection requests, PJM conducts this power flow test as part of baseline analysis under summer and winter peak load conditions, when capacity is most needed to serve load, as well as under light load conditions to ensure that a range of resource combinations and conditions is examined.

Queue Process Overview

PJM's interconnection queue process consists of five phases as shown in **Figure 5.2**. A new service queue request is submitted during one of the two queue windows: April through September and October through March. During the feasibility study phase, the project is evaluated at a primary and a secondary (optional) point of interconnection. PJM targets to complete the feasibility study of a project within 120 days after the close of the queue window.

Figure 5.2: New Services Queue Process Overview



During the impact study phase, the project elects one of the two points of interconnection, and the study is targeted to be completed 120 days after the start of the system impact study phase for the queue – or 120 days after the agreement is signed – whichever is later. During this phase, PJM coordinates with neighboring entities to conduct an affected system study, if applicable. The facilities study phase is targeted to be completed in approximately six months after the Facilities Study Agreement has been executed. This study is conducted by the transmission owner. During the study phases, PJM performs power flow, short circuit and stability analysis to ensure the project's reliable interconnection to PJM's system. When the study phases have been completed, the project signs agreements that grant it the rights to interconnect to the PJM system. The Interconnection Service Agreement and the Construction Service Agreement describe the milestones, point of interconnection, system upgrades, and construction responsibilities that are associated with the project.

5.0.3 — Offshore Wind

States within PJM have a variety of policies and regulations focused on renewable generation objectives. PJM states on the East Coast are seeking to promote the development of offshore wind generation. The state policies of New Jersey look to incent the interconnection of a total of 7,500 MW of offshore wind generation by 2035. In order to achieve the state's public policy objectives, New Jersey has requested a PJM competitive RTEP proposal window in 2021 under the auspices of the PJM RTEP process State Agreement Approach (SAA). The intent of the window is to solicit transmission proposals to deliver future offshore wind generation through the SAA as defined in [PJM's Operating Agreement](#).

Other states, such as Virginia and Maryland, are also implementing policies that call for an increase in offshore wind generation. Driven by these policies, an increased number of offshore wind generation requests over the past few queue windows have been submitted to PJM. Twenty-seven offshore wind projects, predominantly located along the Atlantic coastline, are currently under study, five of which entered the PJM queue during the 2019 queue window. PJM studies these requests to ensure a reliable interconnection of offshore wind generators to the PJM system.

Section 6: State Summaries

PJM | DE | DC | IL | IN | KY | MD | MI | NJ | NC | OH | PA | TN | VA | WV

6.0: Delaware RTEP Summary

6.0.1 — RTEP Context

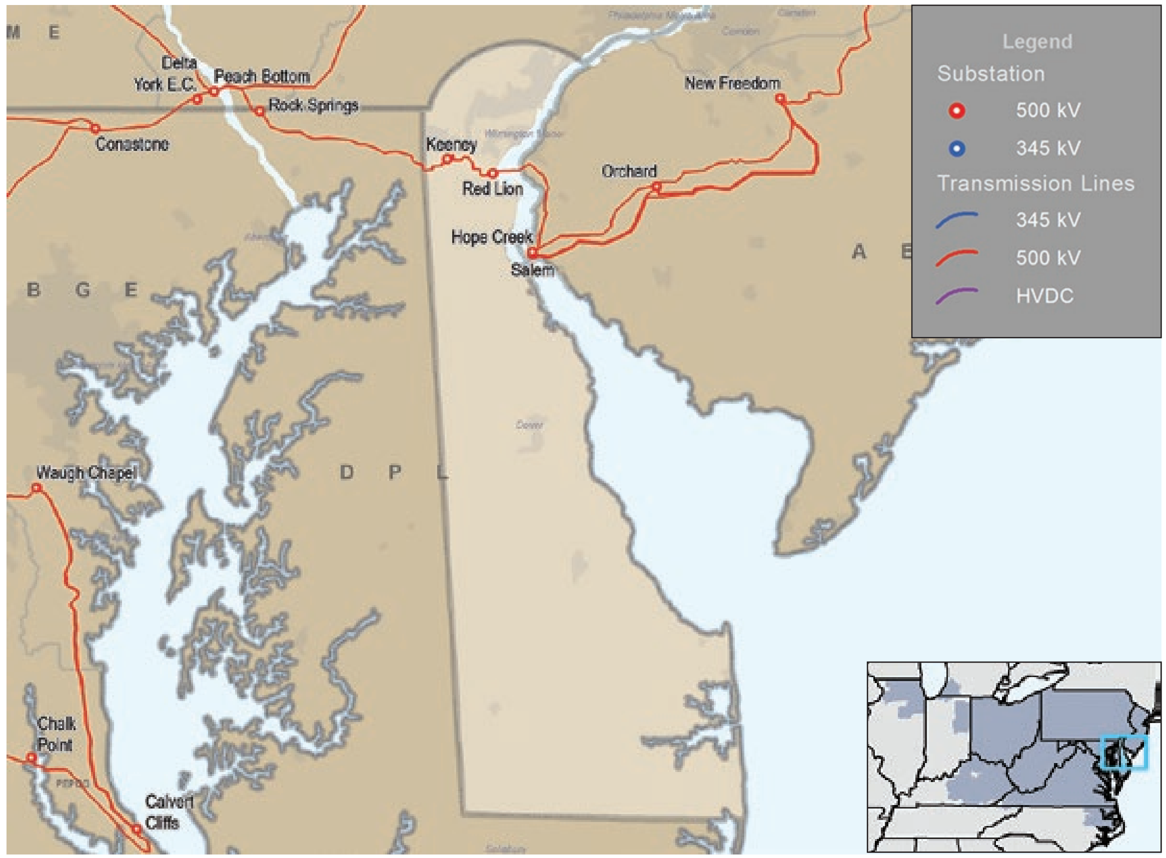
PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Delaware, including facilities owned and operated by Delaware Municipal Electric Corp. (DEMEC), Delmarva Power & Light Co. (DP&L) and Old Dominion Electric Cooperative (ODEC) as shown on **Map 6.1**. Delaware's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside PJM.

Renewable Portfolio Standards

From an energy policy perspective, Delaware has a renewable portfolio standard (RPS) to advance renewable generation. Many states have instituted goals with respect to the percentage of generation expected to be fueled by renewable fuels in coming years.

In 2020, Delaware has a mandatory RPS target of 25 percent by compliance year 2025-2026. This target includes a minimum solar carve-out of 3.5 percent.

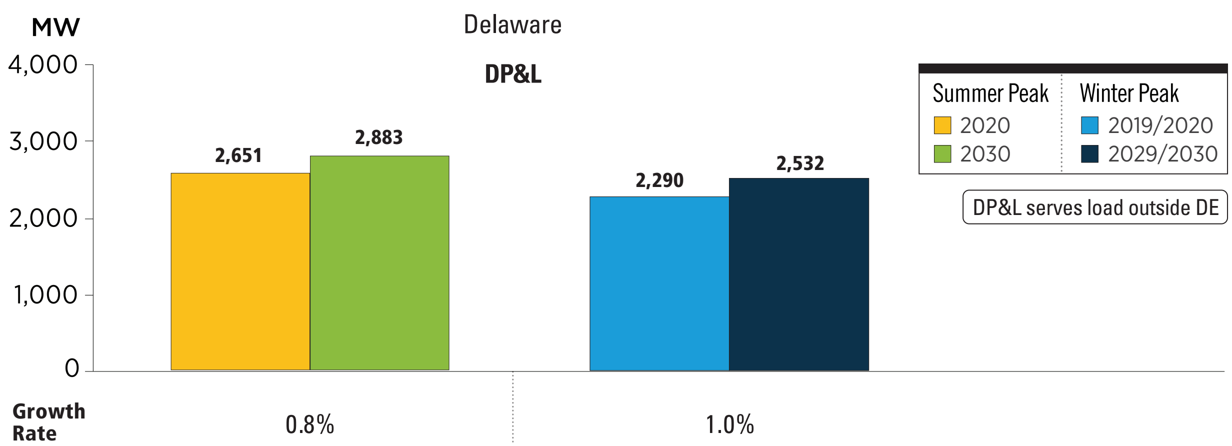
Map 6.1: PJM Service Area in Delaware



6.0.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.1** summarizes the expected loads within the state of Delaware and across PJM.

Figure 6.1: Delaware – 2020 Load Forecast Report



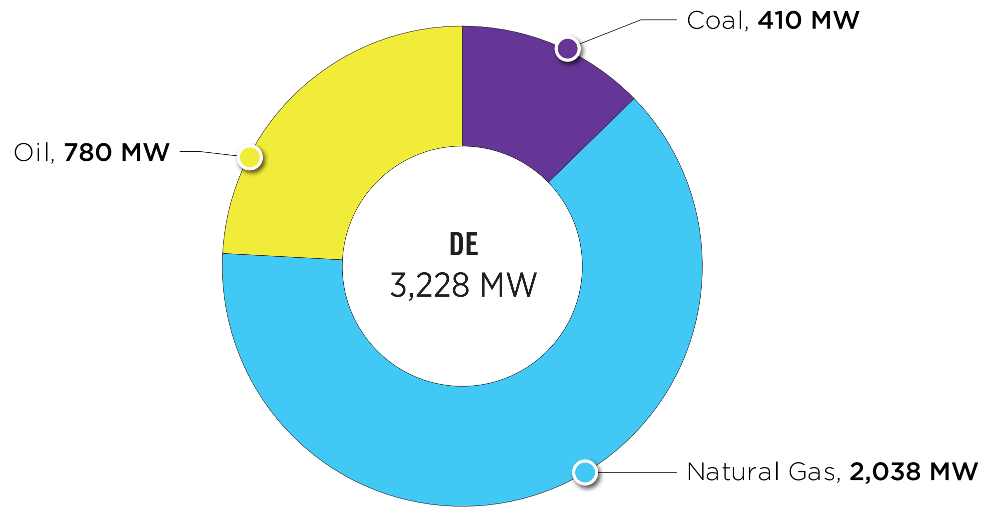
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.0.3 — Existing Generation

Existing generation in Delaware as of Dec. 31, 2020, is shown by fuel type in **Figure 6.2**.

Figure 6.2: Delaware – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



6.0.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Delaware, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in Delaware, as of Dec. 31, 2020, 30 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.1**, **Table 6.2**, **Figure 6.3**, **Figure 6.4** and **Figure 6.5**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.1: Delaware – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2020)

	Delaware Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	0	0.00%	559	0.53%
Natural Gas	451	31.60%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	0	0.00%	31	0.03%
Solar	429	30.06%	58,845	56.13%
Storage	40	2.83%	10,877	10.38%
Wind	507	35.51%	6,560	6.26%
Grand Total	**1,427**	**100.00%**	**104,838**	**100.00%**

Table 6.2: Delaware – Interconnection Requests by Fuel Type (Dec. 31, 2020)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	2	23.0	1	630.0	3	653.0
	Natural Gas	0	0.0	1	451.0	0	0.0	19	1,097.1	19	5,556.4	39	7,104.5
	Oil	0	0.0	0	0.0	0	0.0	5	168.2	1	1.0	6	169.2
	Other	0	0.0	0	0.0	0	0.0	2	30.0	0	0.0	2	30.0
	Storage	3	40.4	0	0.0	0	0.0	0	0.0	4	45.0	7	85.4
Renewable	Biomass	0	0.0	0	0.0	0	0.0	1	0.0	4	24.0	5	24.0
	Methane	0	0.0	0	0.0	0	0.0	4	9.0	3	28.8	7	37.8
	Solar	17	391.4	0	0.0	1	37.6	0	0.0	22	231.5	40	660.4
	Wind	7	442.4	0	0.0	1	64.4	0	0.0	5	396.9	13	903.7
	Grand Total	27	874.2	1	451.0	2	102.0	33	1,327.3	59	6,913.6	122	9,668.0

Figure 6.3: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

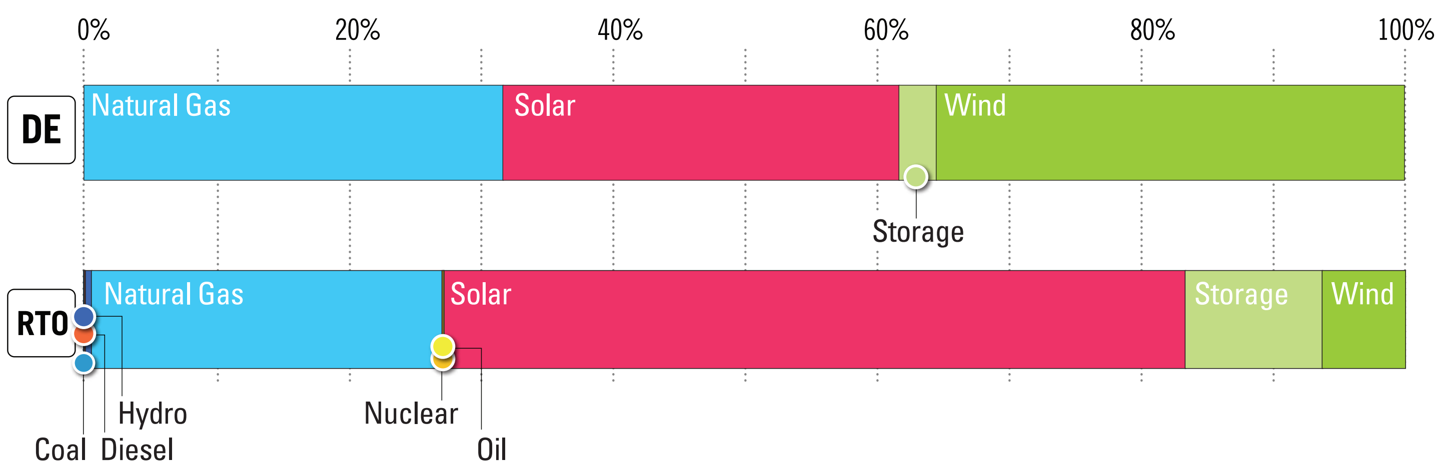
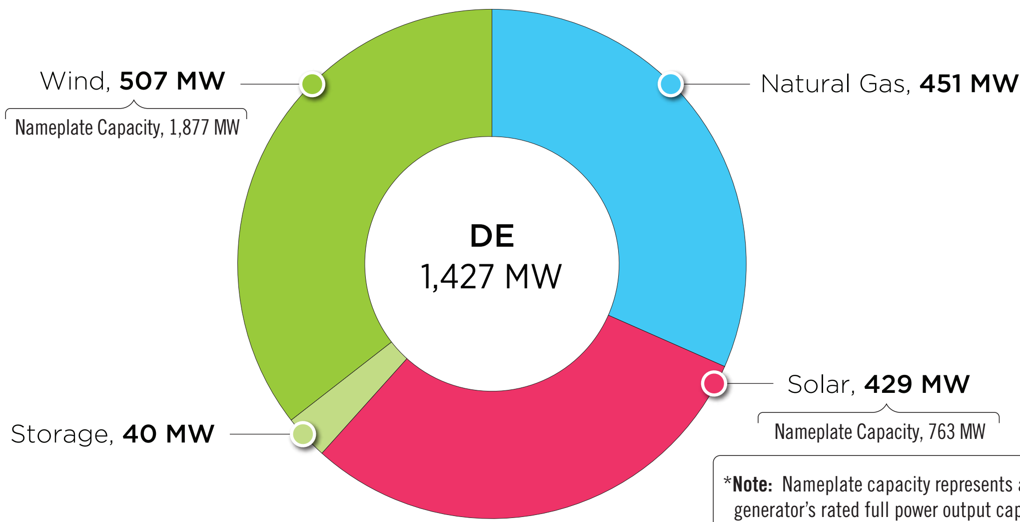
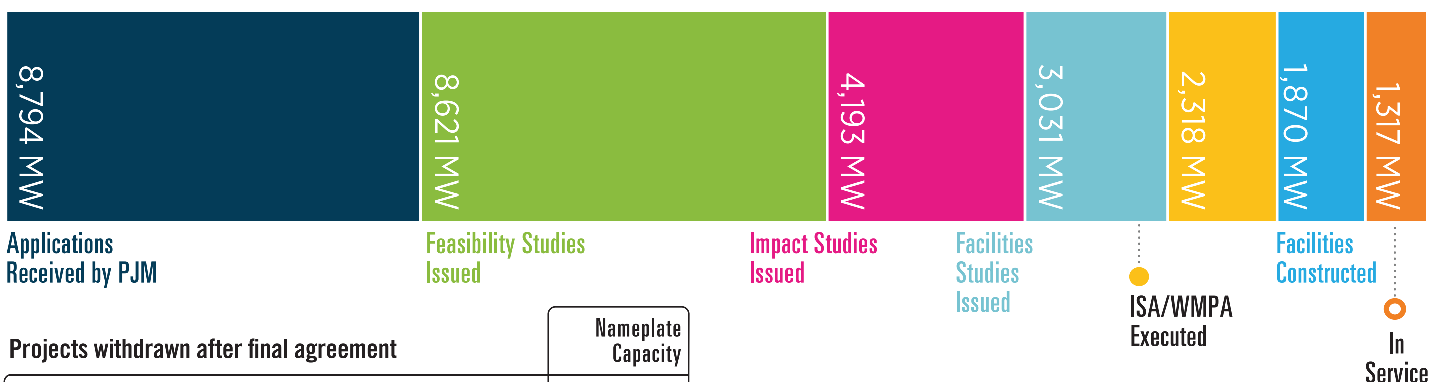


Figure 6.4: Delaware – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)



*Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.5: Delaware Progression History of Queue – Interconnection Requests (Dec. 31, 2020)



Projects withdrawn after final agreement			Nameplate Capacity
3	Interconnection Service Agreements	420 MW	780 MW
5	Wholesale Market Participation Agreements	18 MW	53 MW

Percentage of planned capacity and projects that have reached commercial operation	
15%	34%
Requested capacity megawatts	Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2020.

6.0.5 — Generation Deactivation

There were no known generating unit deactivation requests in Delaware between Jan. 1, 2020, and Dec. 31, 2020, as part of the 2020 RTEP.

6.0.6 — Baseline Projects

No baseline projects greater than or equal to $10 million in Delaware were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.0.7 — Network Projects

No network projects greater than or equal to $10 million in Delaware were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.0.8 — Supplemental Projects

No supplemental projects greater than or equal to $10 million in Delaware were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.0.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in Delaware were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

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6.1: Northern Illinois RTEP Summary

6.1.1 — RTEP Context

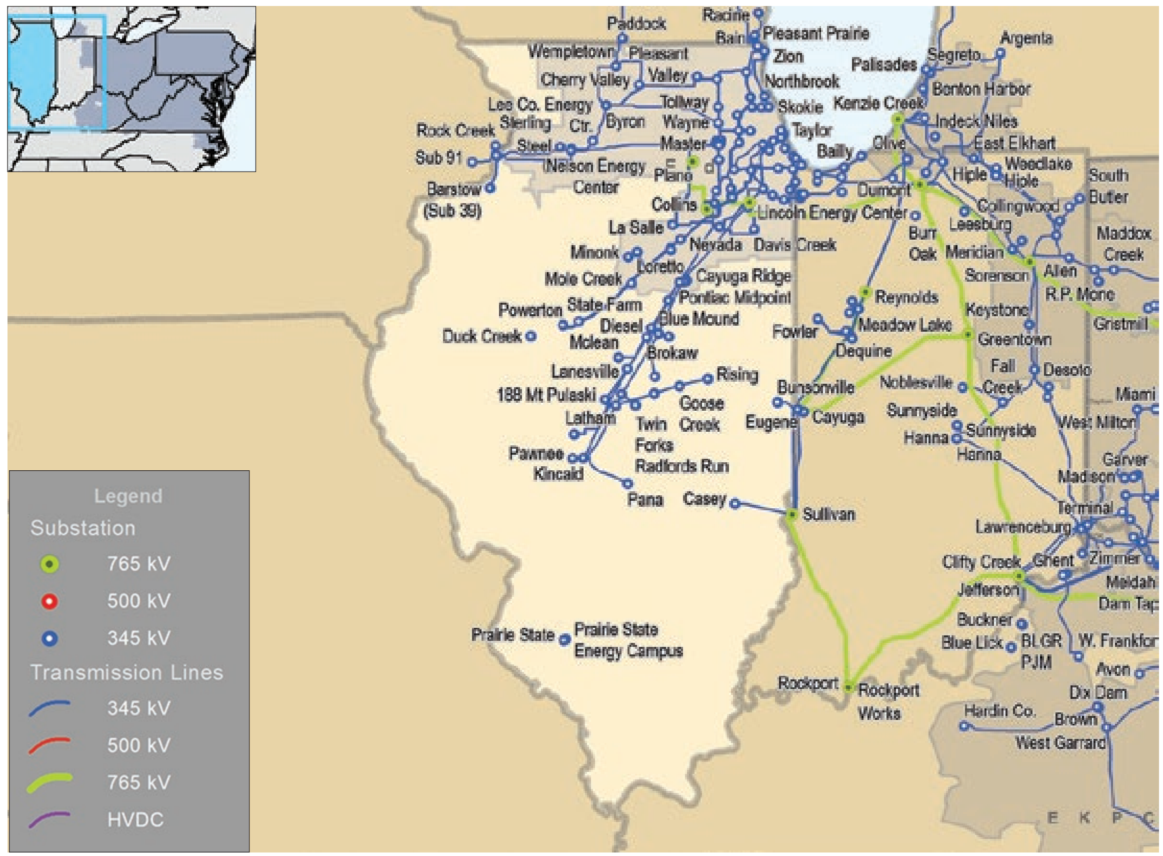
PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Northern Illinois, including facilities owned and operated by Commonwealth Edison Co. (ComEd) and the City of Rochelle as shown on **Map 6.2**. The Northern Illinois' transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Renewable Portfolio Standards

From an energy policy perspective, Illinois has a renewable portfolio standard (RPS) to advance renewable generation. Many states have instituted goals with respect to the percentage of generation expected to be fueled by renewable fuels in coming years.

Illinois has a mandatory RPS target of 25 percent by energy year 2025-2026, and there is a 6 percent solar carve-out within the standard. Illinois also requires that its investor-owned utilities meet 75 percent of this target with wind or photovoltaic resources each year, and for alternative retail electric suppliers this requirement is 60 percent.

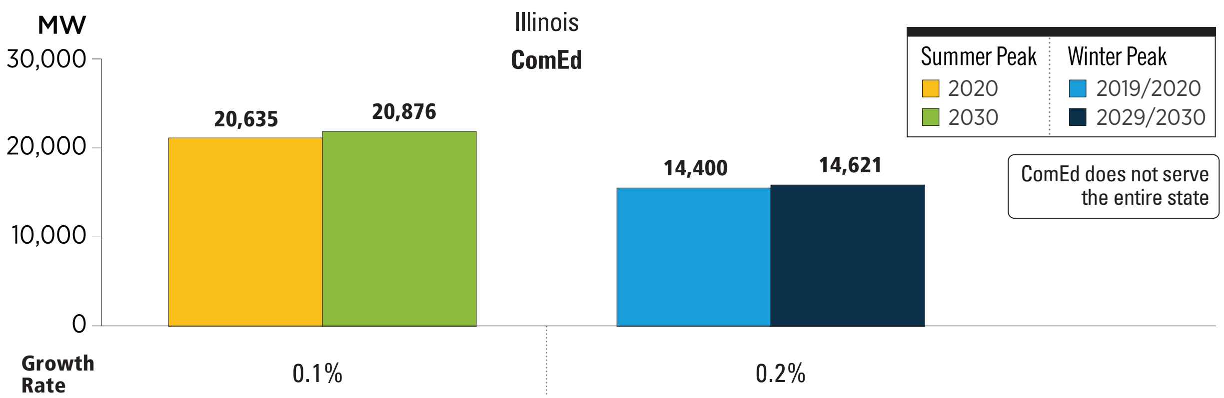
Map 6.2: PJM Service Area in Northern Illinois



6.1.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.6** summarizes the expected loads within the state of Northern Illinois and across all of PJM.

Figure 6.6: Northern Illinois – 2020 Load Forecast Report



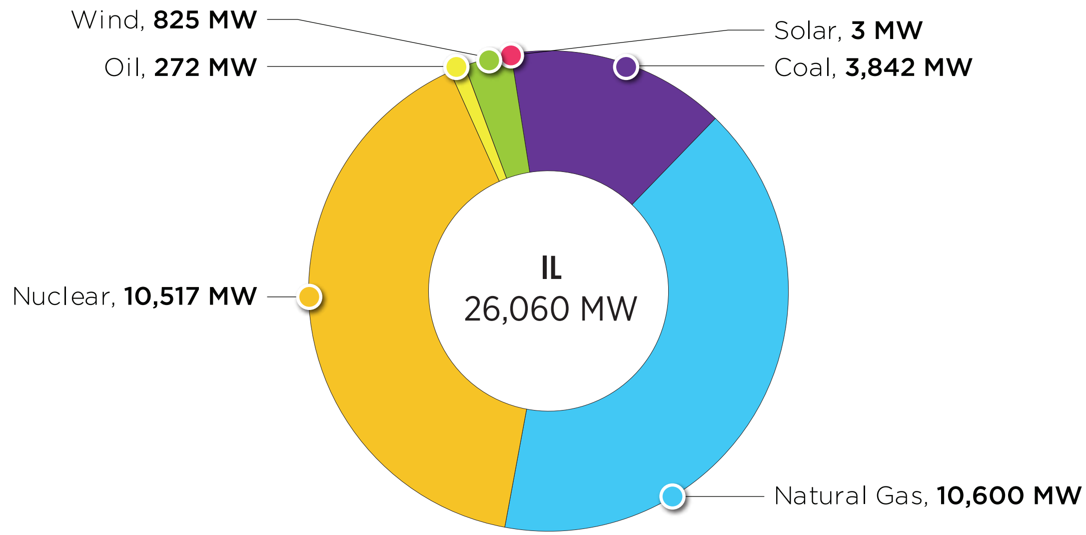
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.1.3 — Existing Generation

Existing generation in Northern Illinois as of Dec. 31, 2020, is shown by fuel type in **Figure 6.7**.

Figure 6.7: Northern Illinois – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



6.1.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Northern Illinois, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in Northern Illinois, as of Dec. 31, 2020, 158 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.3**, **Table 6.4**, **Figure 6.8**, **Figure 6.9** and **Figure 6.10**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.3: Northern Illinois – Capacity by Fuel Type – Interconnection Requests (Dec. 31. 2020)

	Northern Illinois Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	23	0.17%	559	0.53%
Natural Gas	4,812	35.94%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	0	0.00%	31	0.03%
Solar	5,503	41.10%	58,845	56.13%
Storage	1,592	11.89%	10,877	10.38%
Wind	1,460	10.90%	6,560	6.26%
Grand Total	**13,390**	**100.00%**	**104,838**	**100.00%**

Table 6.4: Northern Illinois – Interconnection Requests by Fuel Type (Dec. 31 2021)

		In Queue				Complete				Grand Total	
		Active		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	5	3,652.0	5	3,652.0
	Diesel	0	0.0	0	0.0	2	22.0	0	0	2	22.0
	Natural Gas	15	2,413.3	7	2,398.9	20	1,613.6	21	8,908.3	63	15,334.1
	Nuclear	0	0.0	0	0.0	10	385.8	5	782.0	15	1,167.8
	Other	0	0.0	0	0.0	0	0.0	3	0	3	
	Storage	32	1,592.0	0	0.0	6	0.0	24	511.6	62	2,103.5
Renewable	Biomass	0	0.0	0	0.0	0	0.0	3	90.0	3	90.0
	Hydro	0	0.0	2	22.7	0	0.0	2	4.3	4	27.0
	Methane	0	0.0	0	0.0	4	43.0	14	63.9	18	106.9
	Solar	61	5,502.9	0	0.0	1	3.4	50	1,751.4	112	7,257.7
	Wind	40	1,434.0	1	26.0	31	853.5	110	2,856.7	182	5,170.2
	Grand Total	148	10,942.2	10	2,447.6	74	2,921.3	237	18,620.1	469	34,931.1

Figure 6.8: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

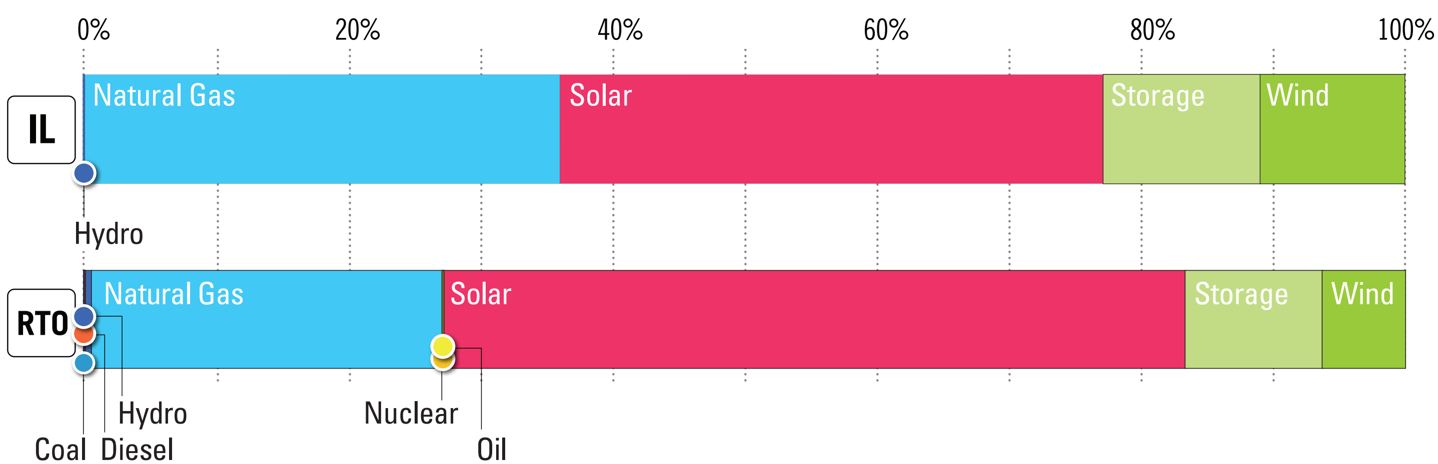


Figure 6.9: Northern Illinois – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)

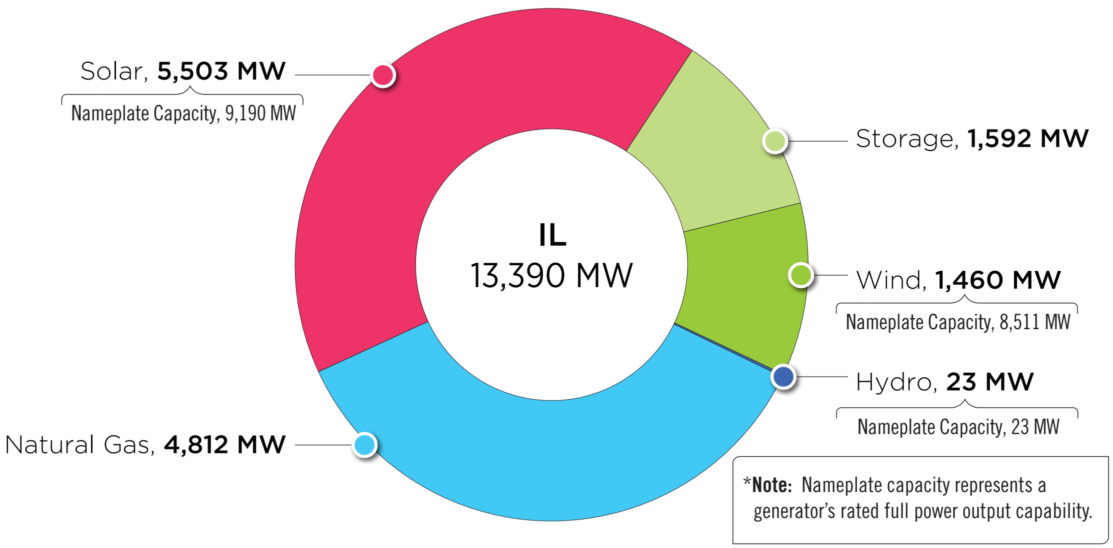
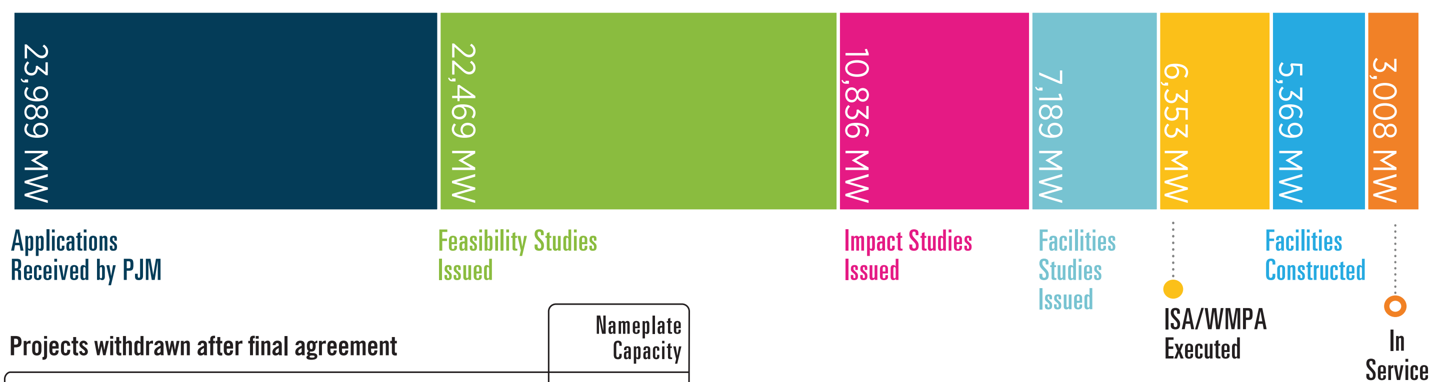


Figure 6.10: Northern Illinois Progression History of Queue – Interconnection Requests (Dec. 31, 2020)



Projects withdrawn after final agreement			Nameplate Capacity
9	Interconnection Service Agreements	376 MW	1,678 MW
4	Wholesale Market Participation Agreements	4 MW	15 MW

Percentage of planned capacity and projects that have reached commercial operation		
	13%	24 %
	Requested capacity megawatts	Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2020.

6.1.5 — Generation Deactivation

Known generating unit deactivation requests in Northern Illinois between Jan. 1, 2020, and Dec. 31, 2020, are summarized in **Map 6.3** and **Table 6.5**.

6.1.6 — Baseline Projects

No baseline projects greater than or equal to $10 million in Northern Illinois were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the [Project Status](#) page of the PJM website.

Map 6.3: Northern Illinois Generation Deactivations (Dec. 31, 2020)

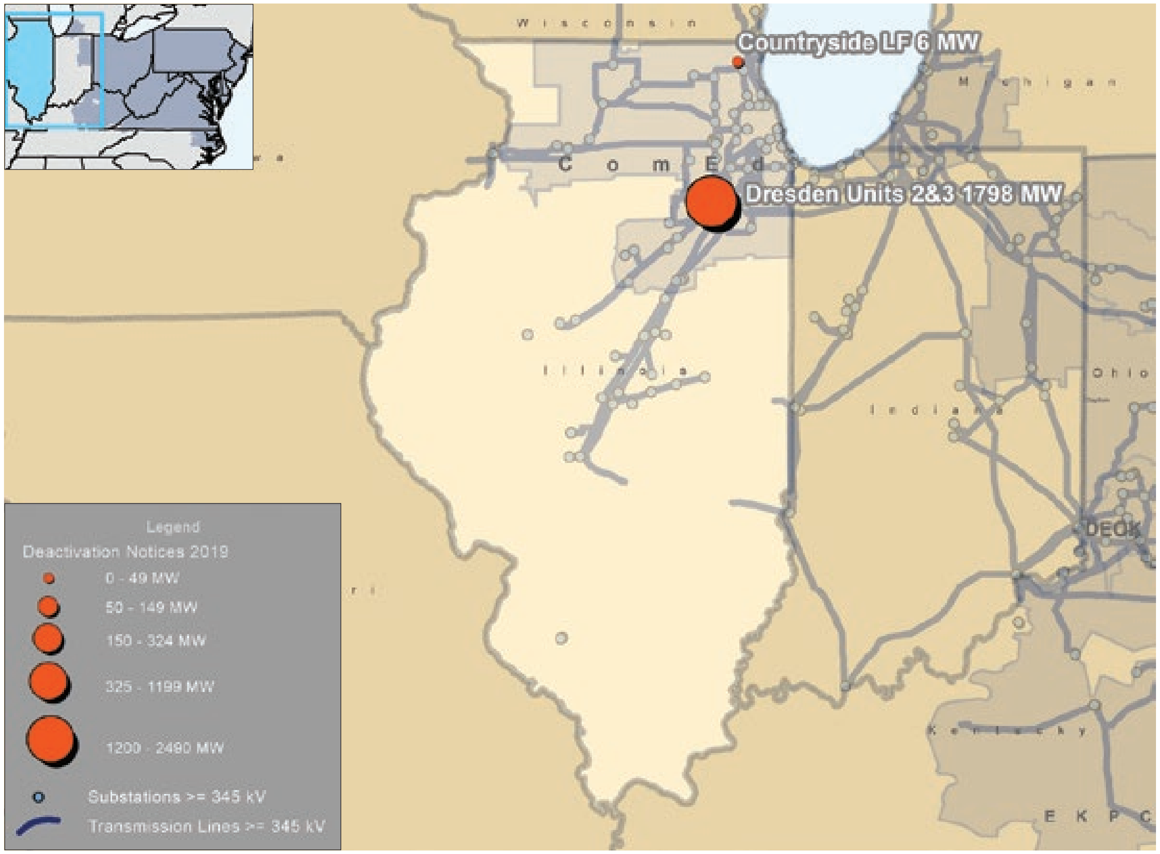


Table 6.5: Northern Illinois Generation Deactivations (Dec. 31, 2020)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Countryside Landfill	ComEd	Methane	10/29/2020	1/27/2021	8	5.8
Dresden Unit 2		Nuclear	8/27/2020	11/1/2021	50	902.5
Dresden Unit 3		Nuclear	8/27/2020	11/1/2021	49	895.5

6.1.7 — Network Projects

2020 RTEP network projects greater than or equal to $10 million in Northern Illinois are summarized in **Map 6.4** and **Table 6.6**.

Map 6.4: Northern Illinois Network Projects (Greater Than or Equal to $10M) (Dec. 31, 2020)

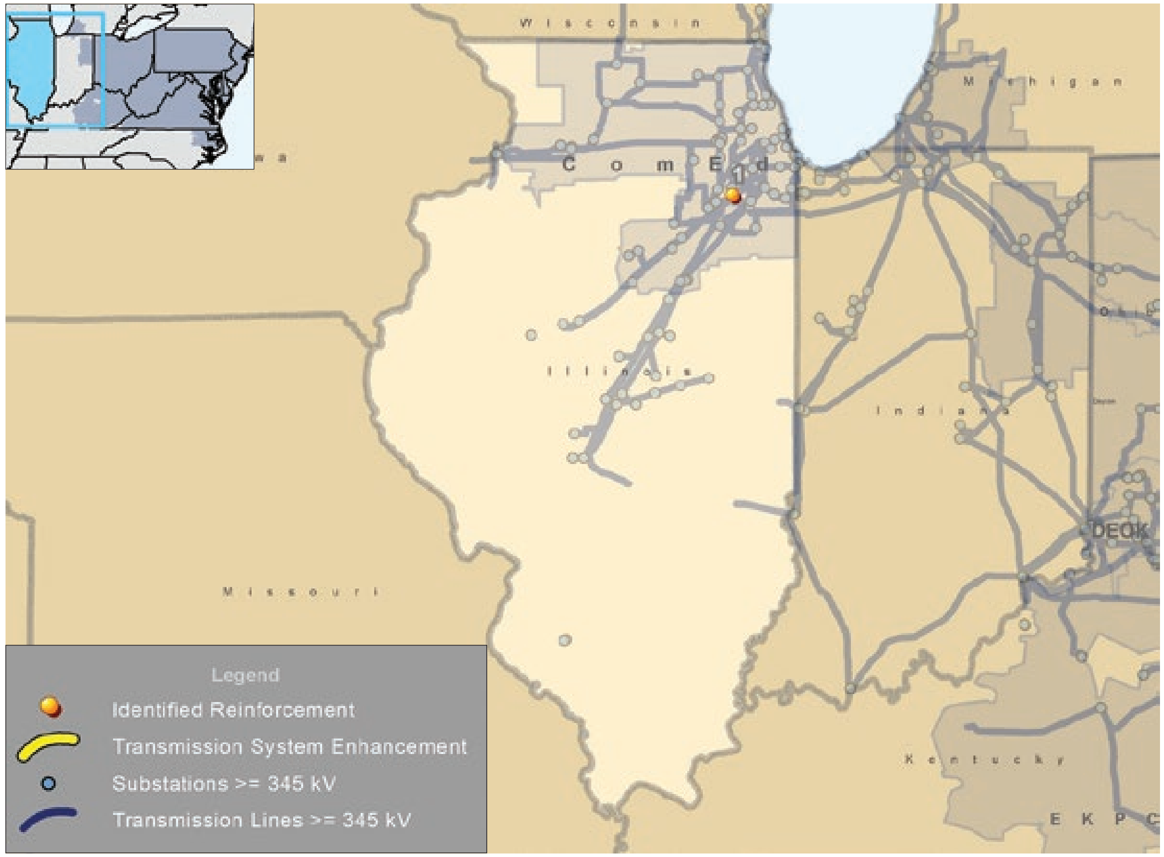


Table 6.6: Northern Illinois Network Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Generation	Required In- Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	**N6025**	Expansion of TSS 900 Elwood to accommodate AC1-204 attachment.	AC1-204	6/1/2022	$35.76	ComEd	9/28/2020

6.1.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in Northern Illinois are summarized in **Map 6.5** and **Table 6.7**.

Map 6.5: Northern Illinois Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

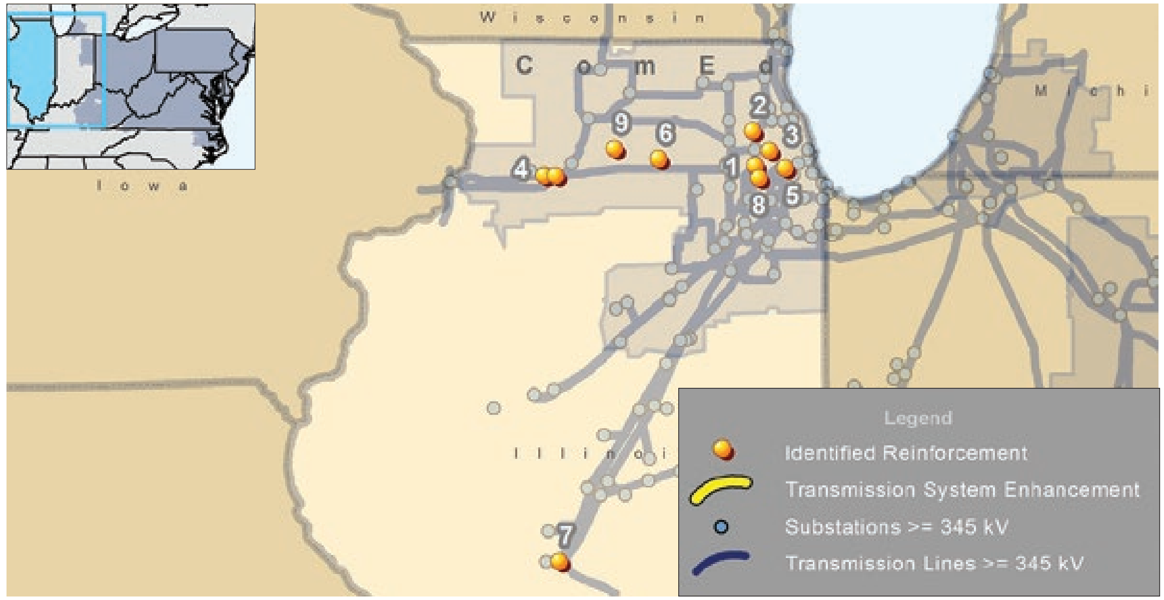


Table 6.7: Northern Illinois Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2247	Replace Lisle Transformer 83. Add high-side CB.	12/31/2021	$10.00	ComEd	4/14/2020
2	S2266	Rebuild Itasca 345 kV bus as an indoor GIS double ring bus expandable to breaker-and-a-half connecting four lines and two transformers. Replace 345/138 kV Transformer 82 and retire tertiary cap bank.	6/1/2024	$65.00		5/12/2020
3	S2267	Rebuild Elmhurst 345 kV bus as indoor GIS double-ring bus, expandable to breaker-and-a-half connecting two lines and three transformers.		$55.00		
4	S2268	Build a second circuit 4.5 miles in existing right-of-way from Nelson 138 kV to tap point and split into a pair of two-terminal lines. Ratings on the new section will be 351/449 MVA SN/SLTE consistent with b2999 project.	6/1/2022	$15.20		5/22/2020
5	S2285	Rebuild McCook 345 kV bus as indoor GIS double ring bus, expandable to breaker-and-a-half (BAAH).	12/31/2024	$64.00		6/2/2020
6	S2349	Cut into existing lines 11323 and 11106. Install new 138 kV breaker-and-a-half substation by Sept. 1, 2021. Install two 138 kV, 43.2 MVAR cap banks, first by June 1, 2022, second by June 1, 2024.	9/1/2021	$61.90		7/17/2020
7	S2350	Replace five 345 kV oil circuit breakers with two-cycle IPO SF6 circuit breakers. Change timer settings for breaker failure relays and remove Kincaid special protection scheme.	12/31/2024	$15.70		7/7/2020
8	S2353	Cut into existing line 1802. Install new 138 kV four-breaker ring bus substation.	6/30/2022	$18.70		8/14/2020
9	S2354	Cut into existing 138 kV line 16914. Install new 138 kV, three-breaker ring substation.	12/31/2021	$15.30		

6.1.9 — Merchant Transmission Project Requests

As of Dec. 31, 2020, PJM's queue contained two merchant transmission project requests with a terminal in Northern Illinois, as shown in **Map 6.6** and **Table 6.8**.

Map 6.6: Northern Illinois Merchant Transmission Project Requests (Dec. 31, 2020)

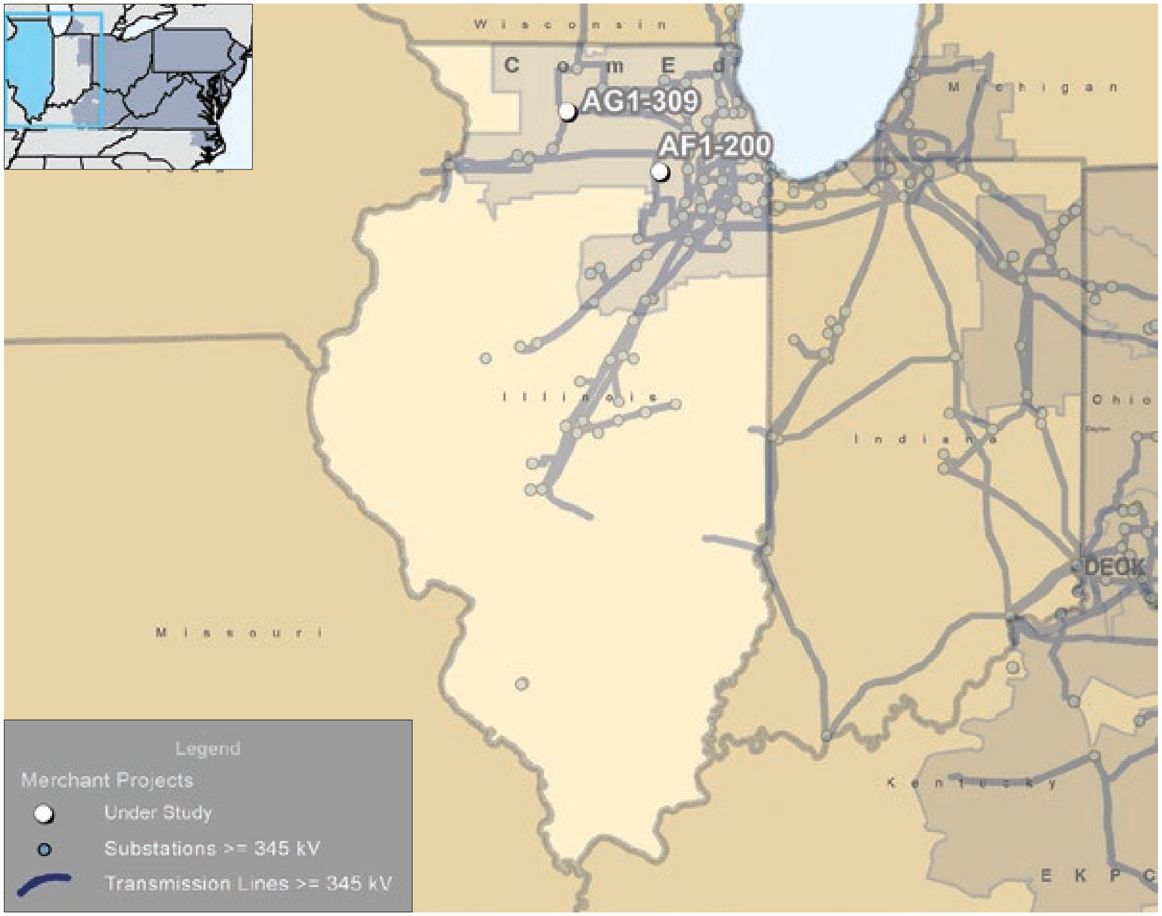


Table 6.8: Northern Illinois Merchant Transmission Project Requests (Dec. 31, 2020)

Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
AF1-200	Plano 345 kV	ComEd	Active	1/31/2025	2,100
AG1-309	Byron 345 kV		Active		2,100

6.2: Indiana RTEP Summary

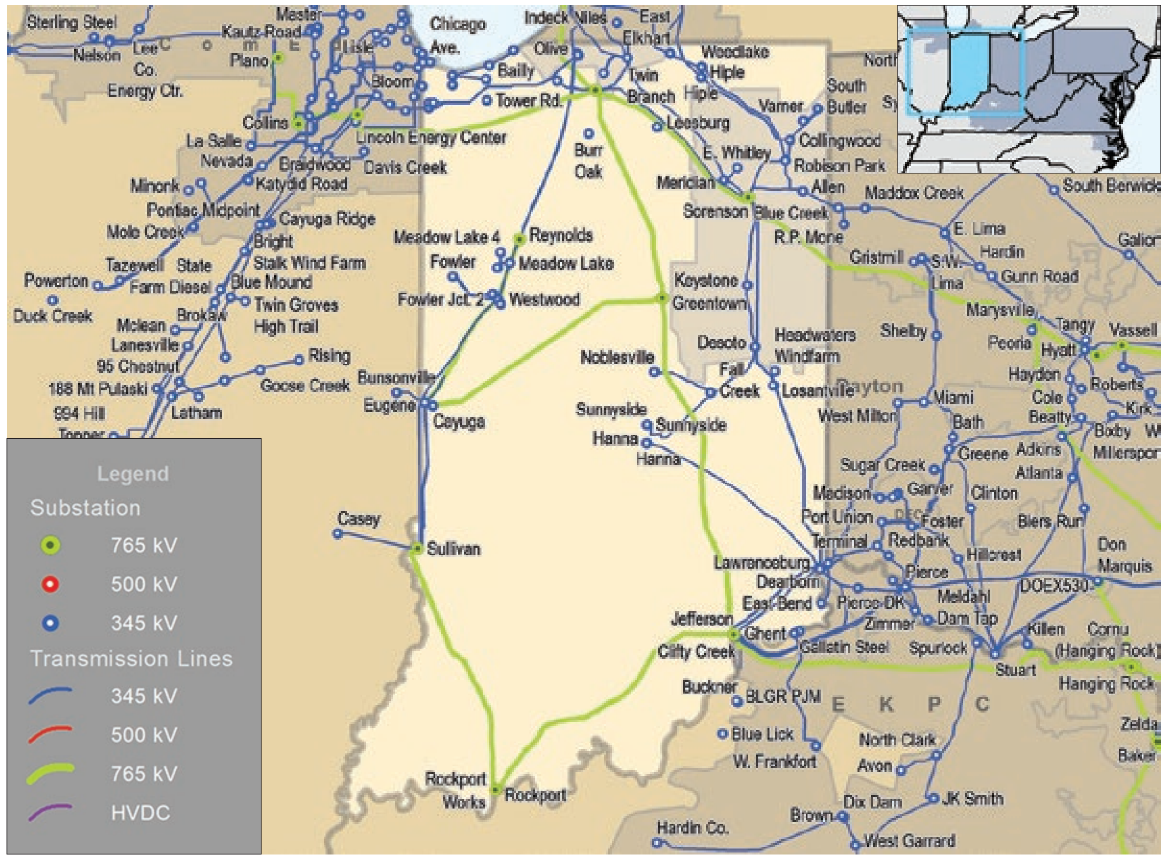
6.2.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Indiana, including facilities owned and operated by American Electric Power (AEP) as shown on **Map 6.7.** Indiana's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Renewable Portfolio Standards

Many states have announced goals to encourage clean and renewable generation in the coming years. From an energy policy perspective, Indiana has a voluntary clean energy portfolio standard of 10 percent by 2025. This target can be met with eligible clean energy technologies, and 50 percent of the qualifying energy must come from within Indiana.

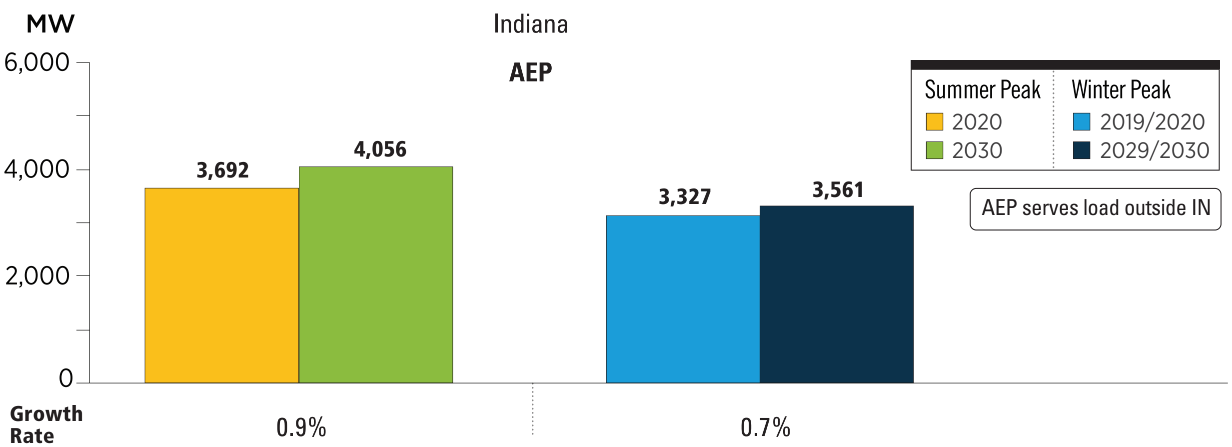
Map 6.7: PJM Service Area in Indiana



6.2.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.11** summarizes the expected loads within the state of Indiana and across all of PJM.

Figure 6.11: Indiana – 2020 Load Forecast Report



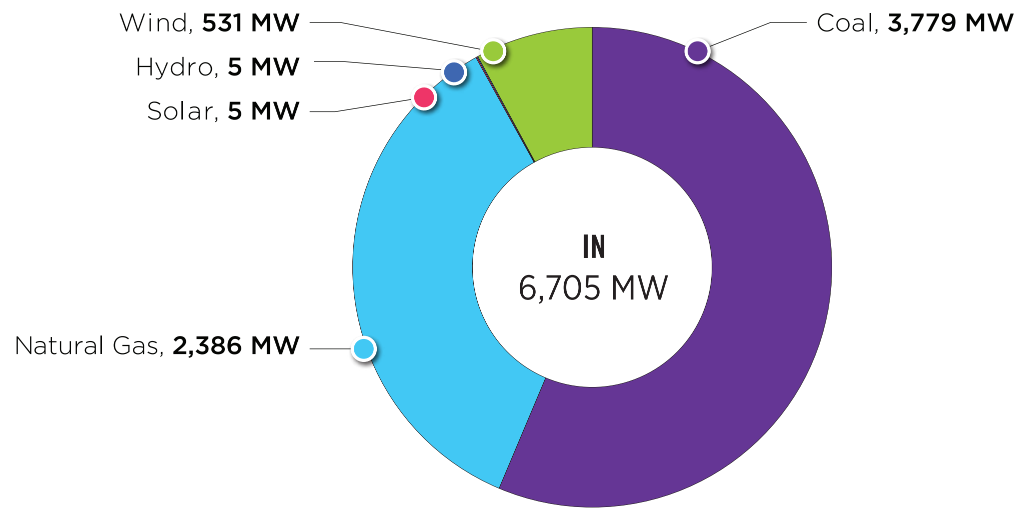
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.2.3 — Existing Generation

Existing generation in Indiana as of Dec. 31, 2020, is shown by fuel type in **Figure 6.12**

Figure 6.12: Indiana – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



6.2.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Indiana, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in Indiana, as of Dec. 31, 2020, 112 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.9**, **Table 6.10**, **Figure 6.13**, **Figure 6.14** and **Figure 6.15**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.9: Indiana – Capacity by Fuel Type – Interconnection Requests (Dec. 31. 2020)

	Indiana Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	0	0.00%	559	0.53%
Natural Gas	1,150	11.44%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	0	0.00%	31	0.03%
Solar	7,469	74.28%	58,845	56.13%
Storage	976	9.71%	10,877	10.38%
Wind	460	4.57%	6,560	6.26%
Grand Total	**10,056**	**100.00%**	**104,838**	**100.00%**

Table 6.10: Indiana – Interconnection Requests by Fuel Type (Dec. 31 2020)

		In Queue				Complete				Grand Total	
		Active		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	4	66.0	2	901.0	6	967.0
	Natural Gas	2	1,100.0	1	50.0	5	811.0	2	1,747.0	10	3,708.0
	Storage	14	976.3	0	0.0	0	0.0	9	382.1	23	1,358.5
Renewable	Methane	0	0.0	0	0.0	2	8.0	1	3.6	3	11.6
	Solar	78	7,469.4	0	0.0	3	5.1	22	3,281.2	103	10,755.6
	Wind	16	433.9	1	26.0	10	388.9	45	1,699.7	72	2,548.5
	Grand Total	110	9,979.6	2	76.0	24	1,279.0	81	8,014.6	217	19,349.2

Figure 6.13: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

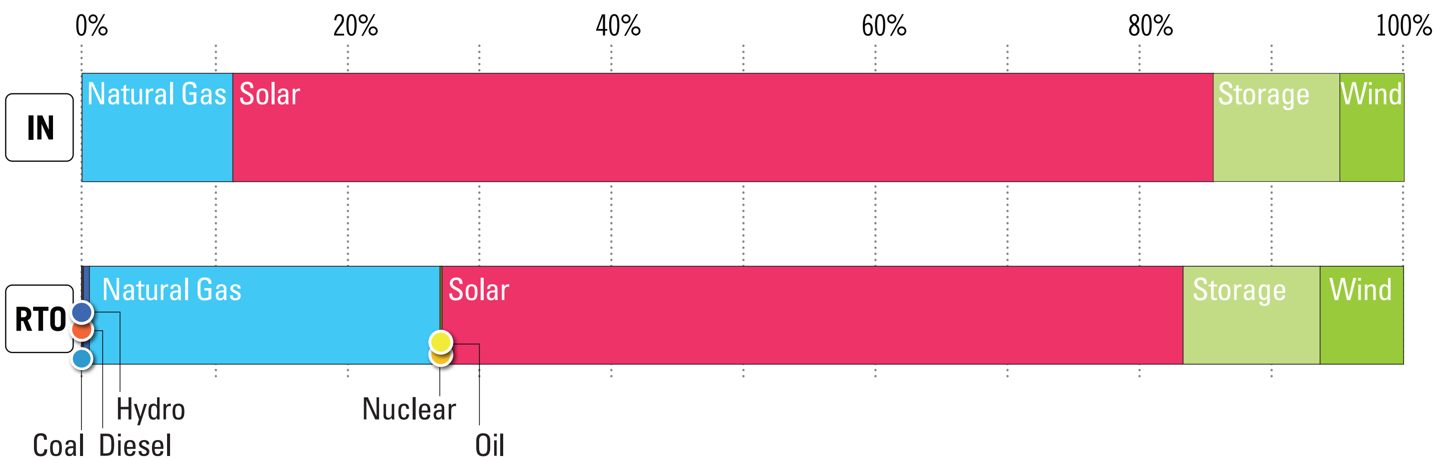


Figure 6.14: Indiana – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)

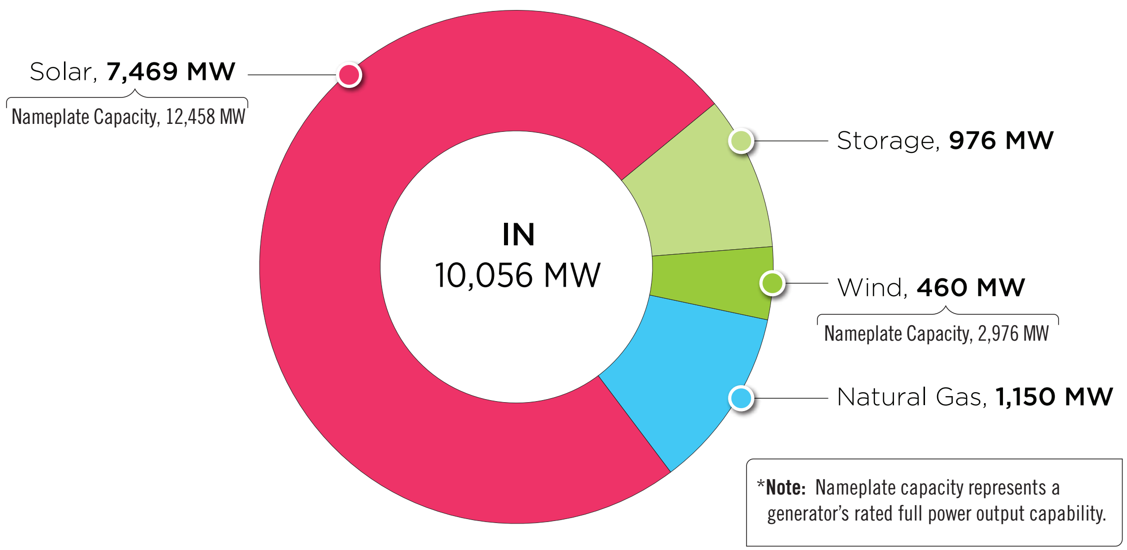


Figure 6.15: Indiana Progression History of Queue – Interconnection Requests (Dec. 31, 2020)

Projects withdrawn after final agreement			Nameplate Capacity
3	Interconnection Service Agreements	71 MW	420 MW

Percentage of planned capacity and projects that have reached commercial operation	14% Requested capacity megawatts	23% Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2020.

6.2.5 — Generation Deactivations

There were no generating unit deactivation requests in Indiana between Jan. 1, 2020, and Dec. 31, 2020, as part of the 2020 RTEP.

6.2.6 — Baseline Projects

2020 RTEP baseline projects greater than or equal to $10 million in Indiana are summarized in **Map 6.8** and **Table 6.11.**

Map 6.8: Indiana Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

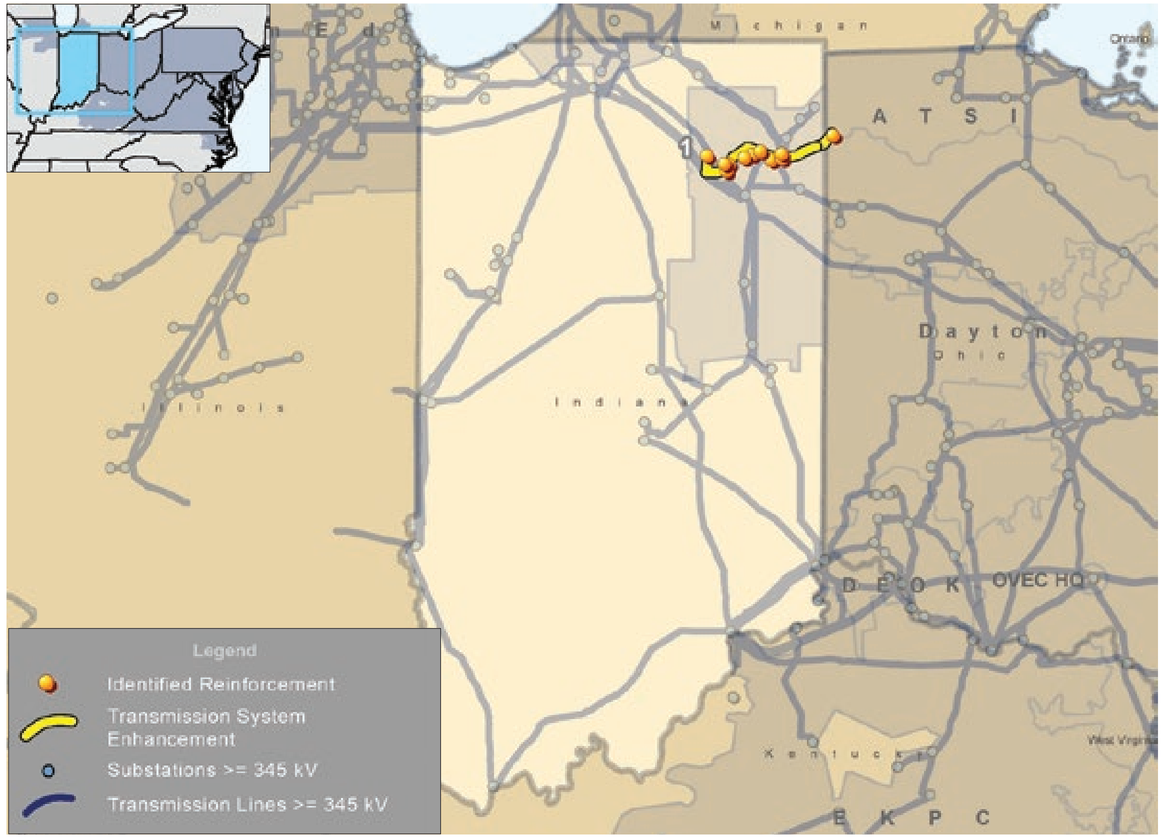


Table 6.11: Indiana Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3151	Rebuild the ~30 mile Gateway-Wallen 34.5 kV circuit as the ~27 mile Gateway-Wallen 69 kV circuit.	6/1/2024	$113.00	AEP	11/22/2019
		Retire the ~3 mile Columbia-Whitley 34.5 kV line.				
		At Gateway station, remove all 34.5 kV equipment and install one 69 kV circuit breaker for the new Whitley line entrance.				
		Rebuild Whitley as a 69 kV station with two line and one bus tie circuit breakers.				
		Replace the Union 34.5 kV switch with a 69 kV switch structure.				

Table 6.11: Indiana Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1 Cont.	B3151	Replace the Eel River 34.5 kV switch with a 69 kV switch structure.	6/1/2024	$113.00	AEP	11/22/2019
		Install a 69 kV Bobay switch at Woodland Station.				
		Replace Carroll and Churubusco 34.5 kV stations with the 69 kV Snapper station. Snapper will have two line circuit breakers, one bus tie circuit breaker and a 14.4 MVAR cap bank.				
		Remove 34.5 kV circuit breaker AD at Wallen station.				
		Rebuild the 2.5 mile Columbia-Gateway 69 kV line.				
		Rebuild Columbia station in the clear as a 138/69 kV station with two 138/69 kV transformers and four-breaker ring buses on the high and low side. Station will reuse 69 kV breakers J and K and 138 kV breaker D.				
		Rebuild the 13 mile Columbia-Richland 69 kV line.				
		Rebuild the 0.5 mile Whitley-Columbia City No. 1 line as 69 kV.				
		Rebuild the 0.5 mile Whitley-Columbia City No. 2 line as 69 kV.				
		Rebuild the 0.6 mile double-circuit section of the Rob Park-South Hicksville / Rob Park-Diebold Road as 69 kV.				

6.2.7 — Network Projects

No network projects greater than or equal to $10 million in Indiana were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.2.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in Indiana are summarized in **Map 6.9** and **Table 6.12**.

Map 6.9: Indiana Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

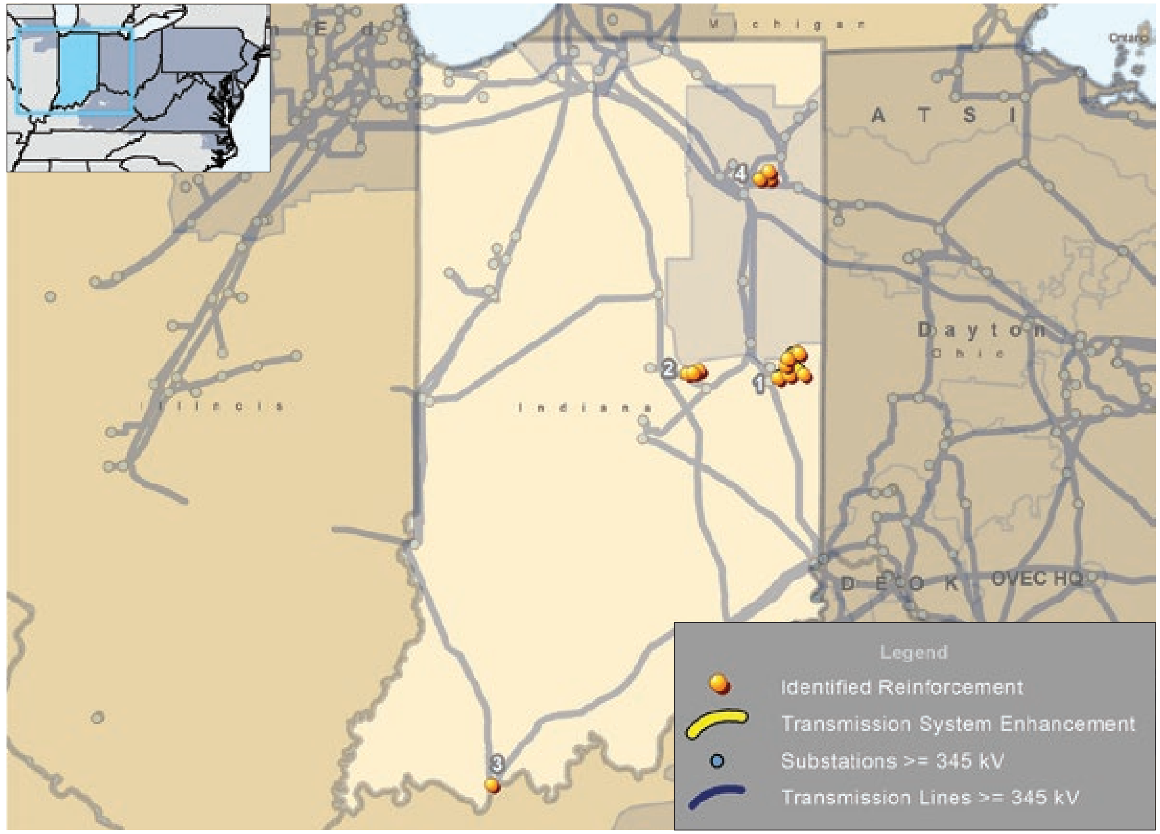


Table 6.12: Indiana Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2273	Rebuild the 1.25 mile long Anchor Hocking-Winchester 69 kV circuit.	8/1/2025	$68.50	AEP	5/22/2020
		Expand and upgrade Anchor Hocking 69 kV station to a five-breaker ring bus to accommodate five elements (two transmission lines and three distribution transformers).				
		Replace circuit breakers A and B at Winchester 69 kV station.				
		At Modoc station, replace 138/69 kV Transformer No. 1. Install a three-breaker ring bus eliminating the three-terminal line.				
		At Randolph station, replace 138/69/12 kV Transformer No. 1 with a 138/69 kV 90 MVA unit. Move the distribution load to a new 138/12kV transformer and install a 138 kV bus tie circuit breaker. Replace cap switcher AA.				

Table 6.12: Indiana Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1 Cont.	S2273	At Lynn station, install two 69 kV switches for sectionalizing.	8/1/2025	$68.50	AEP	5/22/2020
		Replace the Huntsville (REMC) switch structure on the Modoc-Winchester 69 kV line.				
		Rebuild the 13.4 mile Modoc-Winchester 69 kV line with 11.3 miles as single circuit and 2.1 miles as double circuit.				
		Rebuild the 5.7 mile Buena Vista-Lynn 69 kV line as double circuit.				
		Retire Lobdell station. Move the load from 69 kV to 12 kV.				
		Retire Buena Vista Switch 69 kV.				
2	s2274	Rebuild a 4.17 mile portion of the Madison-Pendleton 138 kV single circuit line with DRAKE 795 ACSR 26/7.	5/1/2023	$10.50	AEP	5/22/2020
		At Meadowbrook station, install two 138 kV circuit breakers to eliminate the three-terminal line.				
3	s2280	Replace Rockport CBs B, B2, C and C2 with 765kV SFMT 4000A CBs.	10/1/2024	$18.50		6/2/2020
4	s2344	Rebuild the ~5.8 mile 69 kV line from Colony Bay to the McKinley-Bass line.	4/3/2023	$15.60		7/17/2020
		Add a 69 kV bus tie CB to Hadley station.				

6.2.9 — Merchant Transmission Project Requests

As of Dec. 31, 2020, PJM's queue contained two merchant transmission project requests which include a terminal in Indiana as shown in **Map 6.10** and **Table 6.13.**

Map 6.10: Indiana Merchant Transmission Project Requests (Dec. 31, 2020)

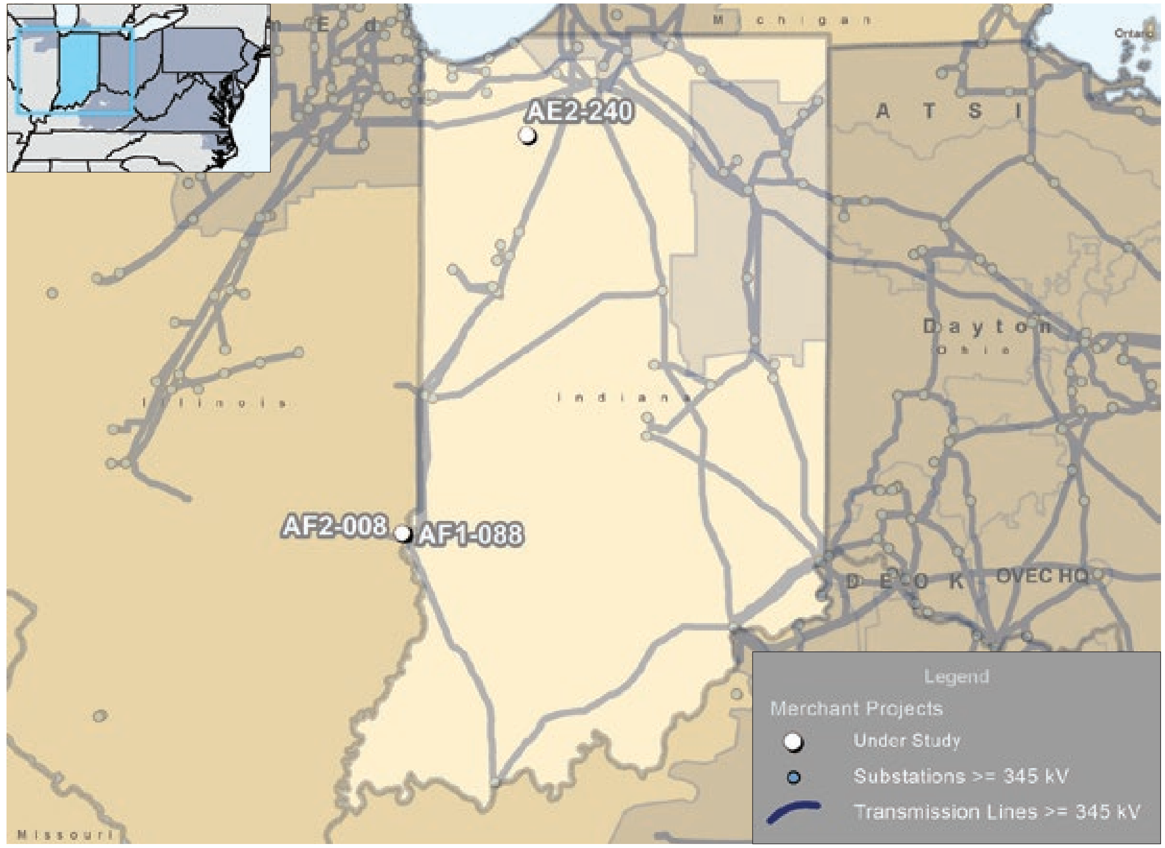


Table 6.13: Indiana Merchant Transmission Project Requests (Dec. 31, 2020)

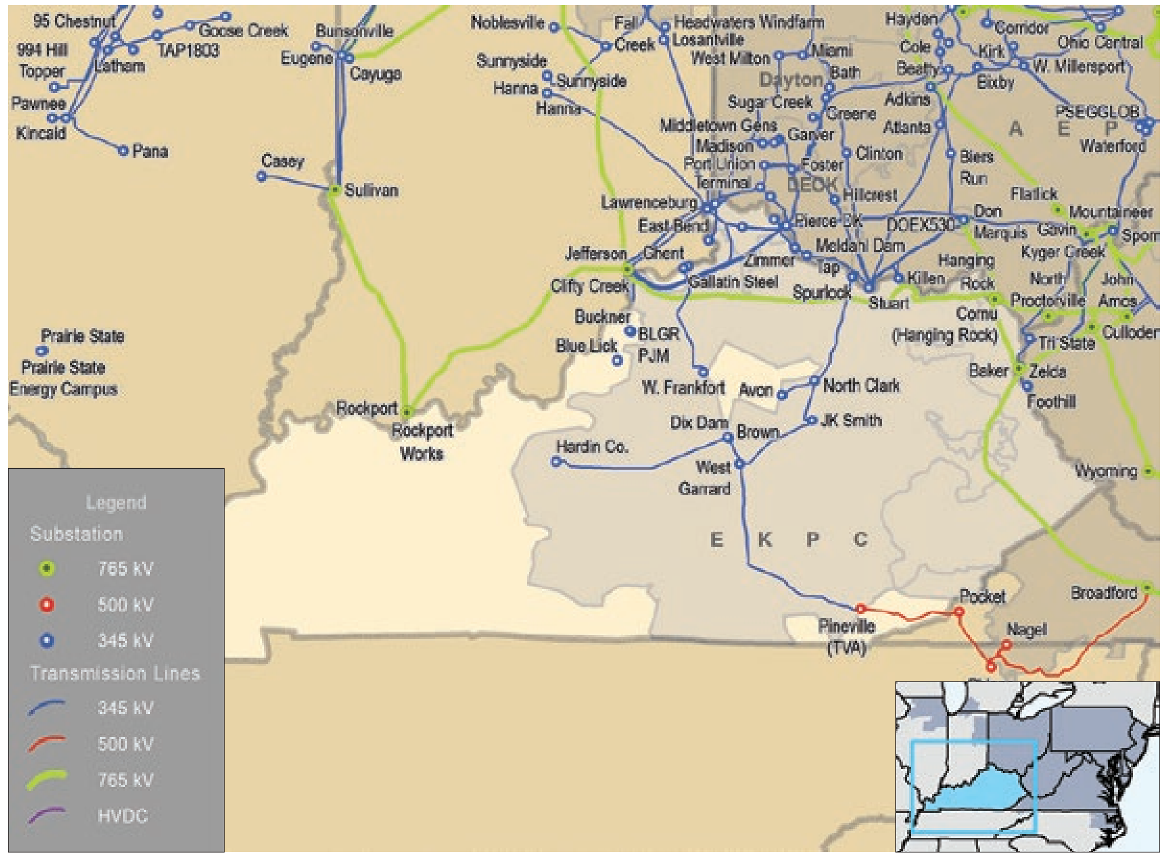
Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
AE2-240	Olive-Reynolds 1 & 2 345 kV	AEP	Active	6/1/2019	3,170
AF1-088	Sullivan 345 kV		Active	12/31/2025	1,000
AF2-008	Sullivan 345 kV		Active		2,000

6.3: Kentucky RTEP Summary

6.3.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Kentucky, including facilities owned and operated by American Electric Power (AEP), Duke Energy Corp. (DEO&K), and East Kentucky Power Cooperative (EKPC) as shown on **Map 6.11**. Duke Energy Corp. (DEO&K) owns the Duke transmission delivery facilities in Kentucky rated over 69 kV. Kentucky's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

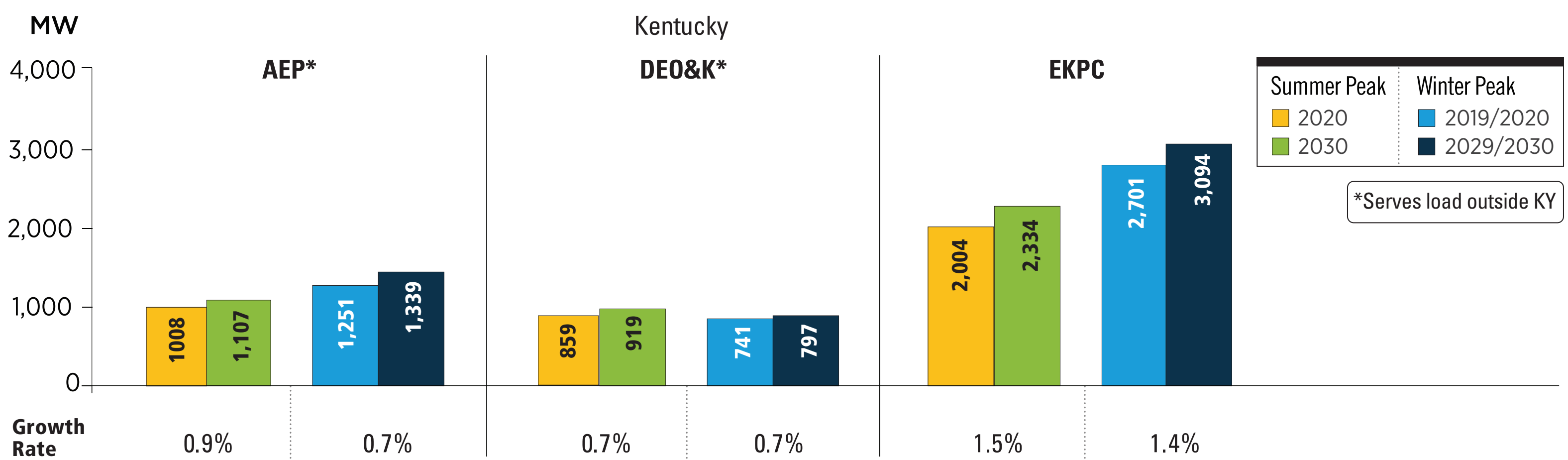
Map 6.11: PJM Service Area in Kentucky



6.3.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.16** summarizes the expected loads within the state of Kentucky and across all of PJM.

Figure 6.16: Kentucky – 2020 Load Forecast Report



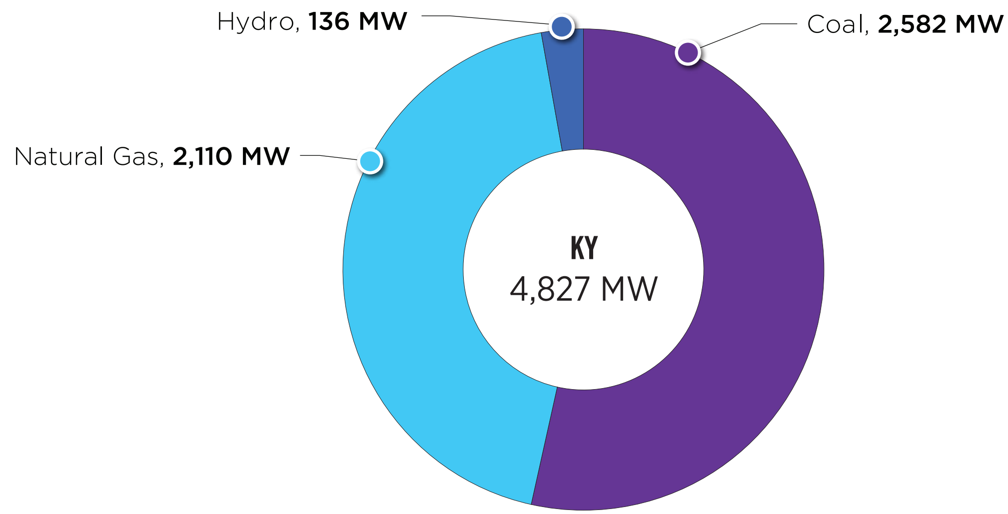
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.3.3 — Existing Generation

Existing generation in Kentucky as of Dec. 31, 2020, is shown by fuel type in **Figure 6.17**.

Figure 6.17: Kentucky – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



6.3.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Kentucky, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in Kentucky, as of Dec. 31, 2020, 62 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.14**, **Table 6.15**, **Figure 6.18**, **Figure 6.19** and **Figure 6.20**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.14: Kentucky – Capacity by Fuel Type – Interconnection Requests (Dec. 31. 2020)

	Kentucky Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	0	0.00%	559	0.53%
Natural Gas	1,100	22.92%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	0	0.00%	31	0.03%
Solar	3,563	74.24%	58,845	56.13%
Storage	136	2.83%	10,877	10.38%
Wind	0	0.00%	6,560	6.26%
Grand Total	4,799	**100.00%**	**104,838**	**100.00%**

Table 6.15: Kentucky – Interconnection Requests by Fuel Type (Dec. 31 2020)

		In Queue				Complete				Grand Total	
		Active		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	6	2,969.0	6	2,969.0
	Natural Gas	0	0.0	1	1,100.0	6	71.0	5	1,704.7	12	2,875.7
	Storage	4	136.0	0	0.0	0	0.0	3	106.2	7	242.2
Renewable	Biomass	0	0.0	0	0.0	0	0.0	5	198.5	5	198.5
	Hydro	0	0.0	0	0.0	0	0.0	1	70.0	1	70.0
	Solar	55	3,434.9	2	127.9	0	0.0	25	1,214.0	82	4,776.8
	Wind	0	0.0	0	0.0	0	0.0	2	27.3	2	27.3
	Grand Total	**59**	**3,570.9**	**3**	**1,227.9**	**6**	**71.0**	**47**	**6,289.7**	**115**	**11,159.5**

Figure 6.18: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

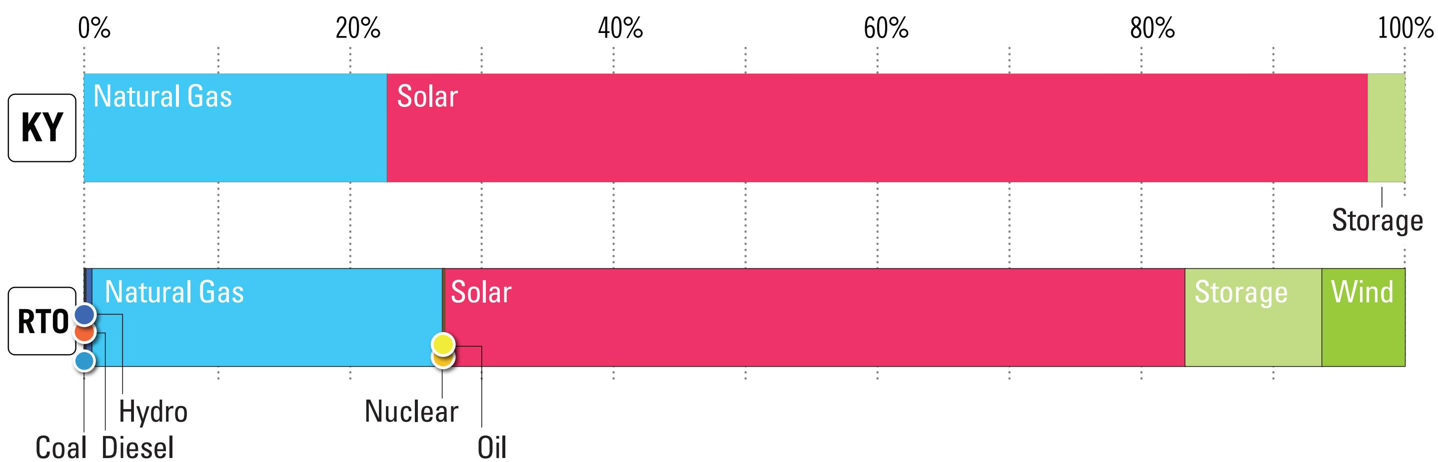
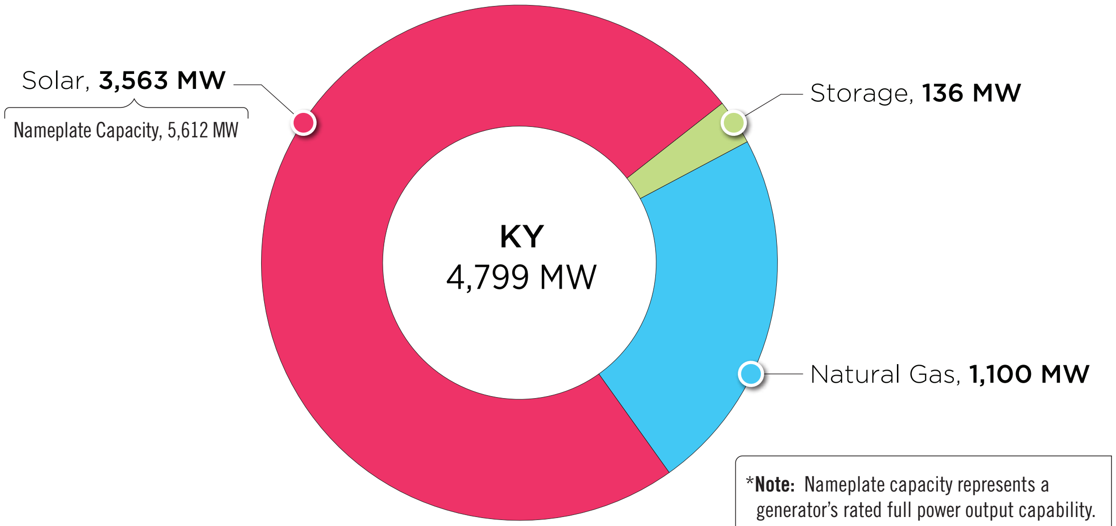


Figure 6.19: Kentucky – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)



*Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.20: Kentucky Progression History of Queue – Interconnection Requests (Dec. 31, 2020)

Projects withdrawn after final agreement			Nameplate Capacity
1	Interconnection Service Agreements	80 MW	80 MW

Percentage of planned capacity and projects that have reached commercial operation		
	1% Requested capacity megawatts	11 % Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2020.

6.3.5 — Generation Deactivation

There were no generating unit deactivation requests in Kentucky between Jan. 1, 2020, and Dec. 31, 2020, as part of the 2020 RTEP.

6.3.6 — Baseline Projects

2020 RTEP baseline projects greater than or equal to $10 million in Kentucky are summarized in **Map 6.12** and **Table 6.16**.

6.3.7 — Network Projects

No network projects greater than or equal to $10 million in Kentucky were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the [Project Status] page of the PJM website.

Map 6.12: Kentucky Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

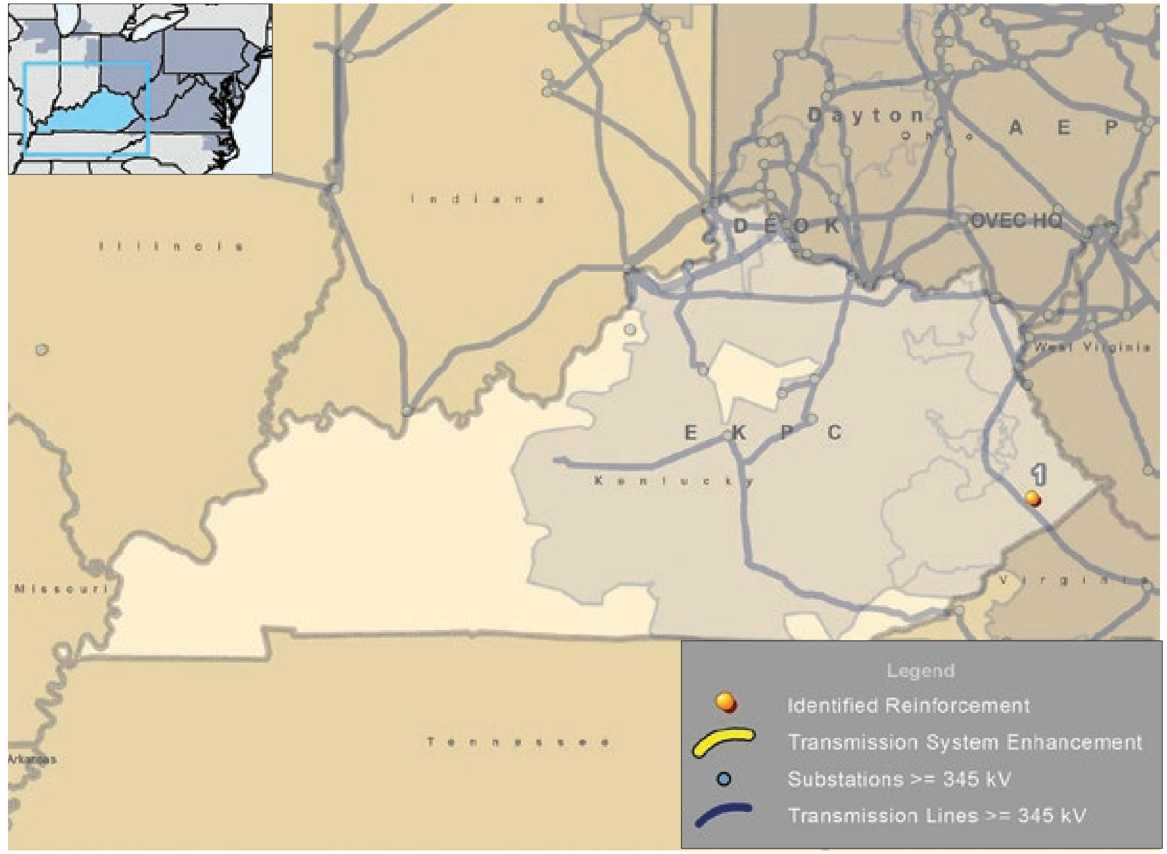


Table 6.16: Kentucky Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3087	Install 28.8 MVAR switching shunt at the new Fords Branch substation.	12/1/2023	$23.70	AEP	10/25/2019

6.3.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in Kentucky are summarized in **Map 6.13** and **Table 6.17**.

6.3.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in Kentucky were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.13: Kentucky Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

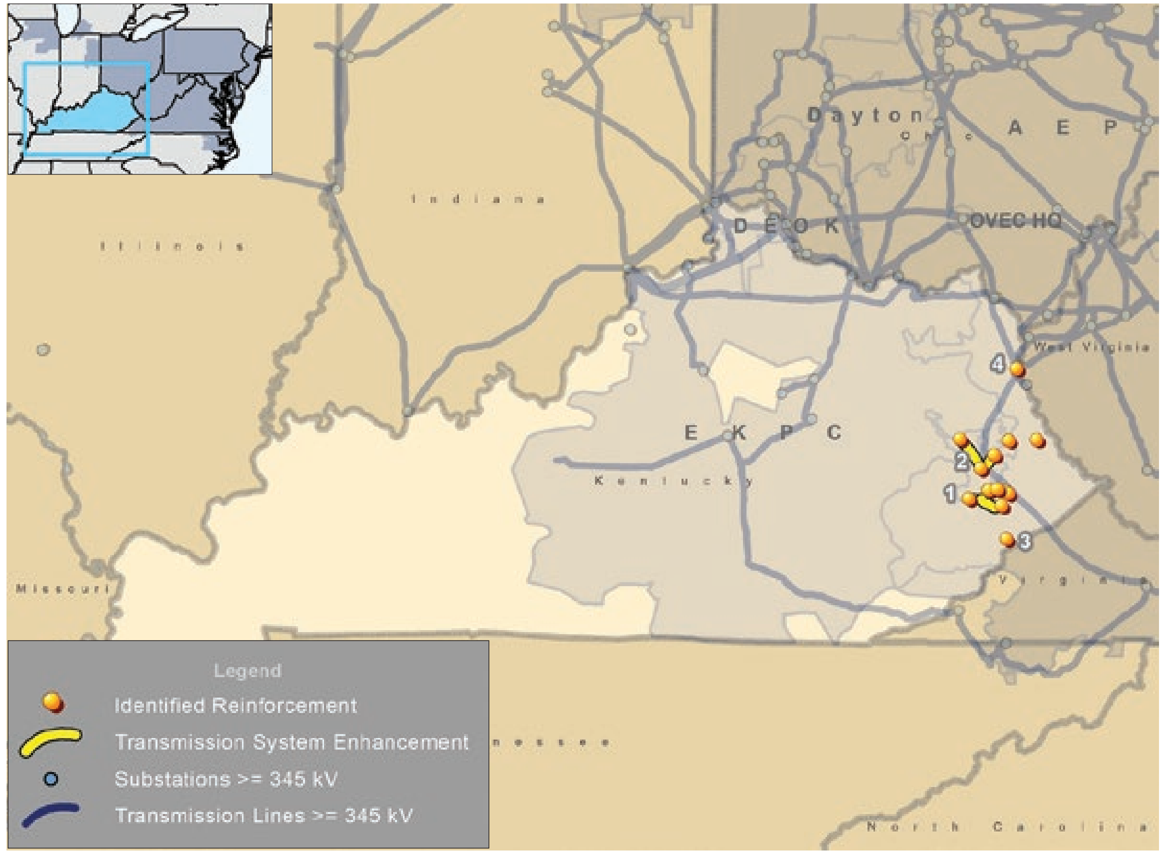
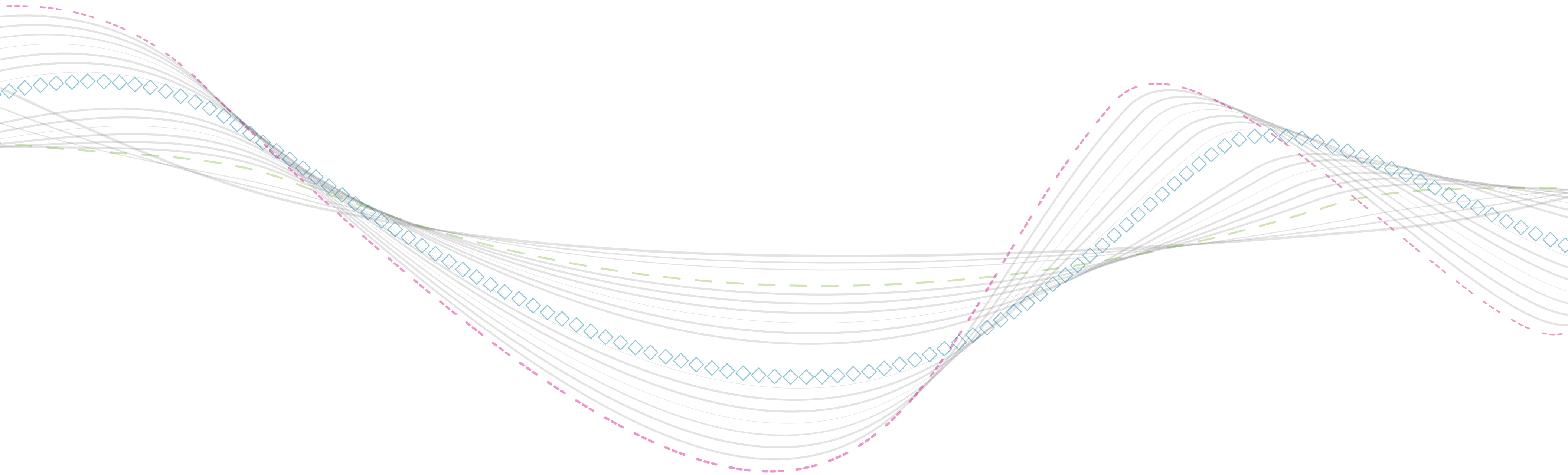


Table 6.17: Kentucky Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2188	Construct ~9.3 miles of single circuit 138 kV from Soft Shell to Garrett picking up Salt Lick Co-op via Snag Fork along the way. Complete associated remote end relaying.	10/31/2023	$81.20	AEP	2/21/2020
		Construct ~3.5 miles of single-circuit 138 kV from the Eastern station to Garrett station. A short extension will be required from the new station to the existing Hays Branch metering point. Construct short extension to existing Morgan Fork-Hays Branch 138 kV circuit from Eastern station.				
		Double circuit cut into existing Hays Branch-Morgan Fork line to tie into new Hays Branch S.S phase-over-phase switch. Install new heavy double circuit dead-end tap structure on the existing Hays Branch-Morgan Fork 138 kV line because of unequal loading on the transmission line.				
		Construct ~0.25 miles of double-circuit 138 kV line named Hays Branch Substation-Eastern. Install three double-circuit suspension structures, one of which is a custom pole structure.				
		New phase-over-phase switch structure at Hays Branch to accommodate new line from Eastern station.				
		Expand Garrett station. Install a 138 kV, three-breaker ring bus and138/12 kV 30 MVA transformer. If space becomes a constraint, we should look at installing a straight bus arrangement with two 138 kV breakers and a circuit switcher on the high side of the transformer.				
		Establish a new 138 kV substation named Eastern south of the existing Hays Branch station. Install two 138 kV breakers (3000A 40kA) at the new Eastern station on exits toward Morgan Fork and Garrett station.				
		Establish Snag Fork substation. Install a three-way phase-over-phase motorized (automated) switching structure near Saltlick to serve the East Kentucky Power Cooperative.				
		Move the existing 69 kV rated circuit breaker G to the Beaver Creek-McKinney No.2 circuit exit at McKinney substation.				
		Install a 138 kV breaker (3000A 40kA) with an exit towards Garrett station (via Snag Fork) at Softshell substation.				
		Retire ~25 miles of the 46 kV Beaver Creek-McKinney No.1 46 KV circuit. Retire Spring Fork Tap.				
2	S2200	Install a 2 MW Battery Energy Storage System (BESS) at Middle Creek substation.	12/1/2020	$41.30	AEP	1/17/2020
		Rebuild ~8.5 miles of 46 kV line between Prestonsburg and Middle Creek station.	4/1/2023			
		Retire ~14.5 miles of 46 kV line between Falcon and Middle Creek.				
3	S2219	Rebuild Fleming station in the clear. Replace 138/69 kV Fleming Transformer No.1 with 138/69 kV, 130 MVA transformer with high side 138 kV CB; install a 5-breaker, 69 kV ring bus on the low side of the transformer, replace 69 kV circuit switcher AA, replace 69/12 kV transformer No. 3 with 69/12 kV, 30 MVA transformer. Replace 12 kV circuit breakers A and D. Retire existing Fleming substation.	9/1/2022	$21.10	AEP	3/19/2020
4	S2281	At Inez station, replace Breakers B, B2, C and C1. Install three new 138 kV breakers and create third string in the existing breaker-and-a-half configuration. Replace 138/69 kV Inez Transformer No. 1 with a 138/69 kV/12 kV 90 MVA autotransformer. Move the new Inez 139/69/12 kV Transformer No. 1 and Martiki 138 kV feed to the new string. Install Breaker B1 towards Johns Creek to complete the string. Installation of Breaker B1 and the third string addresses dissimilar zones of protection between the No. 1 bus and the more-than-20-mile Inez to Johns Creek 138 kV circuit and dissimilar zones of protection between the 138 kV bus No. 2, 138/69 kV transformer No. 1, and the 138 kV circuit to the Martiki coal service point. Replace cap bank switchers CS-BB and CS-CC with 138 kV circuit breakers. Replace obsolete relays at Inez substation. Retire 69 kV capacitor bank and the circuit switcher AA.	9/1/2022	$12.40	AEP	6/19/2020
		Remote end work at Big Sandy, Logan, Sprigg and Dewey substations.				



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6.4: Maryland/District of Columbia RTEP Summary

6.4.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Maryland and the District of Columbia, including facilities owned and operated by Allegheny Power (AP), Baltimore Gas and Electric Co. (BGE), Delmarva Power & Light Co. (DP&L), Potomac Electric Power Co. (PEPCO) and Southern Maryland Electric Cooperative (SMECO) as shown on **Map 6.14**. Maryland and the District of Columbia's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside PJM.

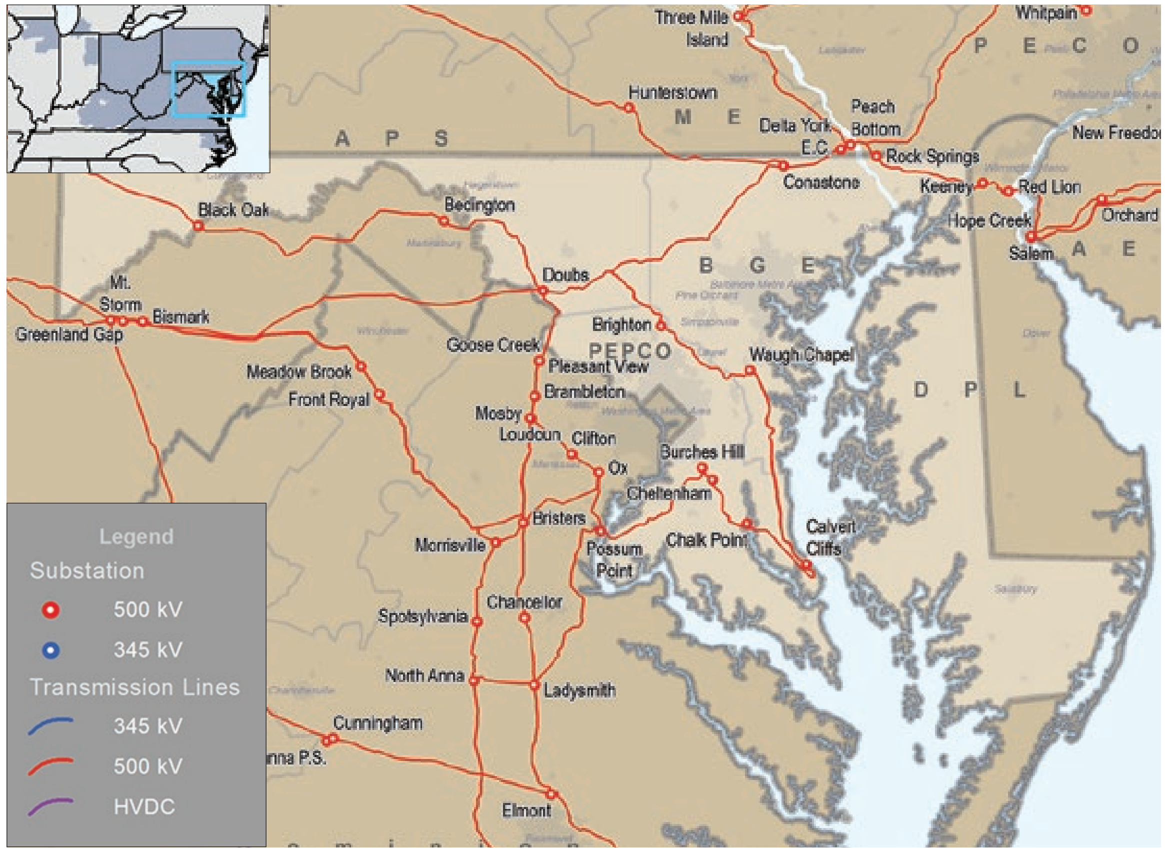
Renewable Portfolio Standards

From an energy policy perspective, Maryland and the District of Columbia both have a renewable portfolio standard (RPS) to advance renewable generation. Many states have instituted goals with respect to the percentage of generation expected to be fueled by renewable fuels in coming years.

Maryland has a mandatory RPS target of 50 percent Tier 1 renewable resources by 2030. This includes a solar carve-out target of at least 14.5 percent by 2028, which must come from in-state solar resources.

The District of Columbia has a mandatory RPS target of 100 percent by 2032. The District's RPS target is one of two in the PJM region set at 100 percent, with the other being Virginia's. The resources serving D.C.'s RPS target must be Tier 1 renewable resources, and beginning in 2029 can only be resources located within the PJM region. The RPS target also includes a solar carve-out target of 5.5 percent by 2032 and 10 percent by 2041.

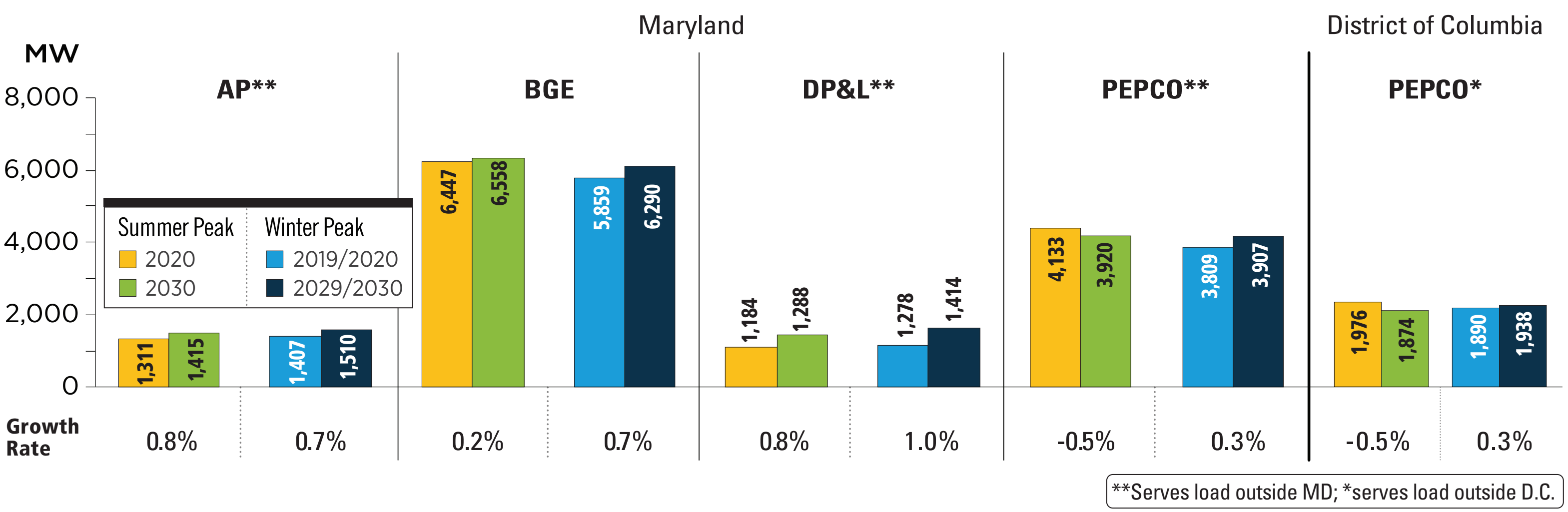
Map 6.14: PJM Service Area in Maryland/District of Columbia



6.4.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.21** summarizes the expected loads within the state of Maryland and the District of Columbia and across all of PJM.

Figure 6.21: Maryland/District of Columbia – 2020 Load Forecast Report



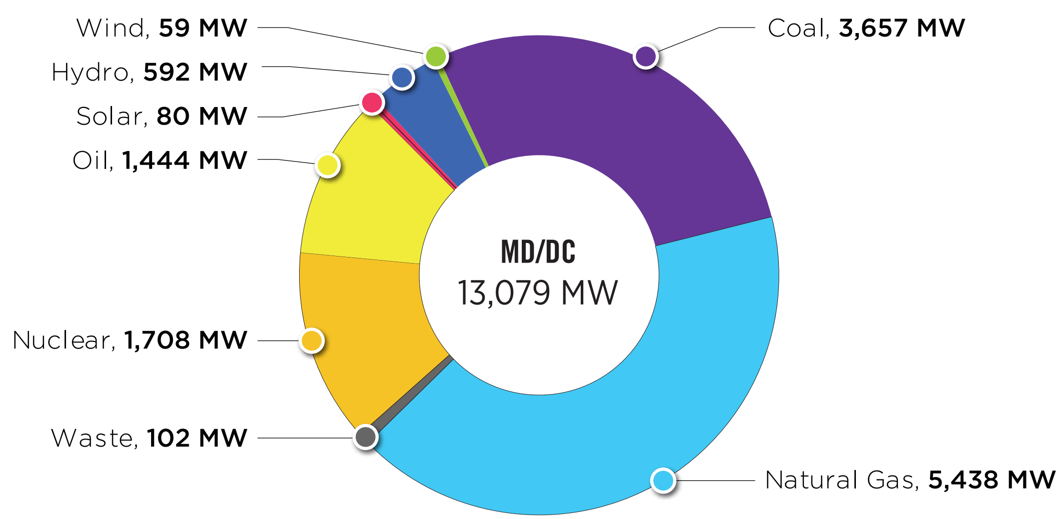
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.4.3 — Existing Generation

Existing generation in Maryland and the District of Columbia as of Dec. 31, 2020, is shown by fuel type in **Figure 6.22**.

Figure 6.22: Maryland/District of Columbia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



6.4.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Maryland and the District of Columbia, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in Maryland and the District of Columbia, as of Dec. 31, 2020, 106 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.18**, **Table 6.19**, **Figure 6.23**, **Figure 6.24** and **Figure 6.25**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.18: Maryland/District of Columbia – Capacity by Fuel Type – Interconnection Requests (Dec. 31. 2020)

	Maryland/D.C. Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	0	0.00%	559	0.53%
Natural Gas	173	6.95%	27,804	26.52%
Nuclear	37	1.51%	81	0.08%
Oil	18	0.72%	31	0.03%
Solar	1,868	75.19%	58,845	56.13%
Storage	388	15.63%	10,877	10.38%
Wind	0	0.00%	6,560	6.26%
Grand Total	**2,484**	**100.00%**	**104,838**	**100.00%**

Table 6.19: Maryland/District of Columbia – Interconnection Requests by Fuel Type (Dec. 31 2020)

		In Queue						Complete					
		Active		Suspended		Under Construction		In Service		Withdrawn		Grand Total	
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	1	10.0	0	0.0	1	10.0
	Diesel	0	0.0	0	0.0	0	0.0	1	0.0	1	5.0	2	5.0
	Natural Gas	8	172.6	0	0.0	1	0.0	34	3,827.2	64	32,860.5	107	36,860.3
	Nuclear	3	37.4	0	0.0	0	0.0	1	0.0	4	4,955.0	8	4,992.4
	Oil	3	18.0	0	0.0	0	0.0	2	5.0	1	2.0	6	25.0
	Other	0	0.0	0	0.0	0	0.0	0	0.0	4	132.0	4	132.0
	Storage	14	388.2	0	0.0	0	0.0	0	0.0	35	293.2	49	681.4
Renewable	Biomass	0	0.0	0	0.0	0	0.0	0	0.0	12	227.6	12	227.6
	Hydro	0	0.0	0	0.0	0	0.0	3	60.0	4	88.4	7	148.4
	Methane	0	0.0	0	0.0	0	0.0	6	18.5	6	18.3	12	36.8
	Solar	47	1,585.1	7	72.8	22	209.8	13	42.2	172	1,021.6	261	2,931.4
	Wind	0	0.0	0	0.0	0	0.0	5	40.3	10	265.6	15	305.9
Other	Battery	1	0.0	0	0.0	0	0.0	0	0.0	0	0.0	1	0.0
	Grand Total	**76**	**2,201.3**	**7**	**72.8**	**23**	**209.8**	**66**	**4,003.2**	**313**	**39,869.2**	**485**	**46,356.2**

Figure 6.23: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

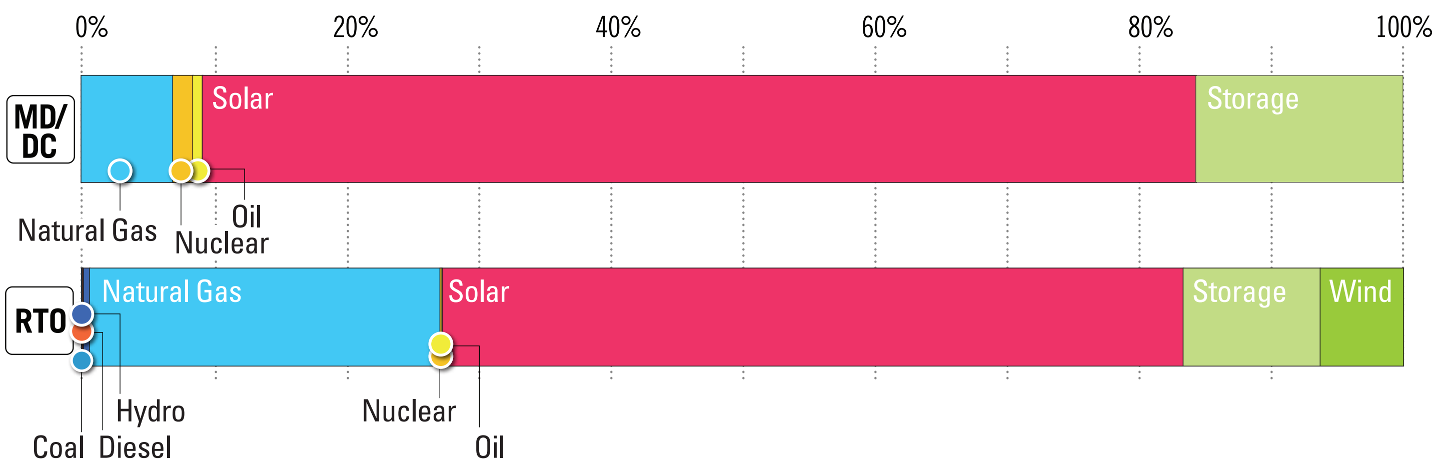
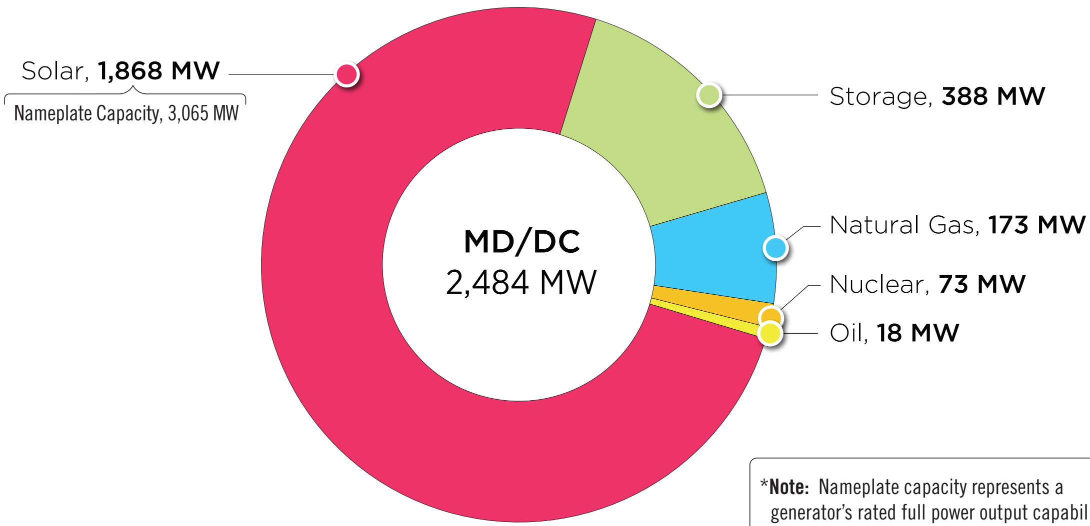
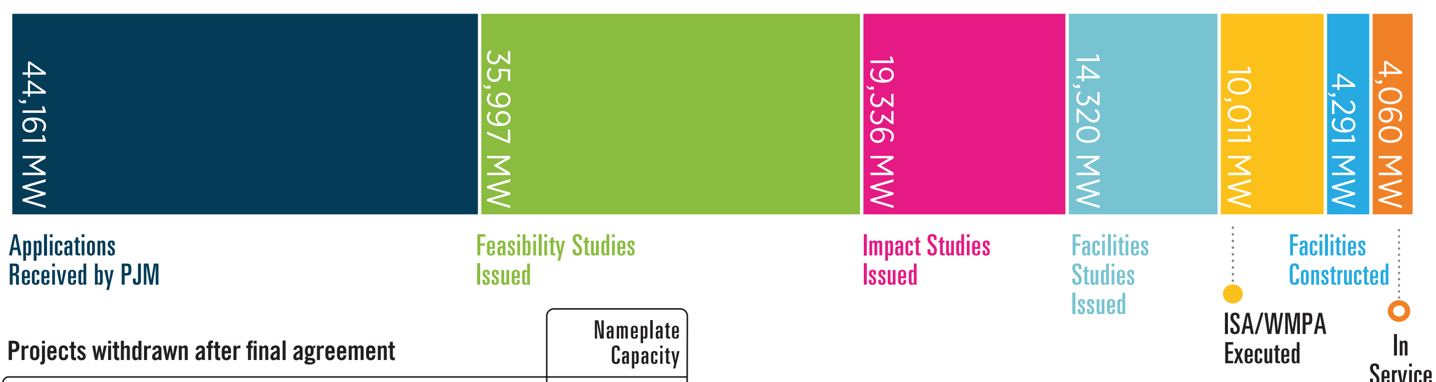


Figure 6.24: Maryland/District of Columbia – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)



*Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.25: Maryland/District of Columbia Progression History of Queue – Interconnection Requests (Dec. 31, 2020)



Projects withdrawn after final agreement			Nameplate Capacity
26	Interconnection Service Agreements	5,627 MW	6,064 MW
44	Wholesale Market Participation Agreements	93 MW	179 MW

Percentage of planned capacity and projects that have reached commercial operation	9% Requested capacity megawatts	17% Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2020.

6.4.5 — Generation Deactivation

Known generating unit deactivation requests in Maryland and the District of Columbia between Jan. 1, 2020, and Dec. 31, 2020, are summarized in **Map 6.15** and **Table 6.20**.

Map 6.15: Maryland/Distirct of Columbia Generation Deactivations (Dec. 31, 2020)

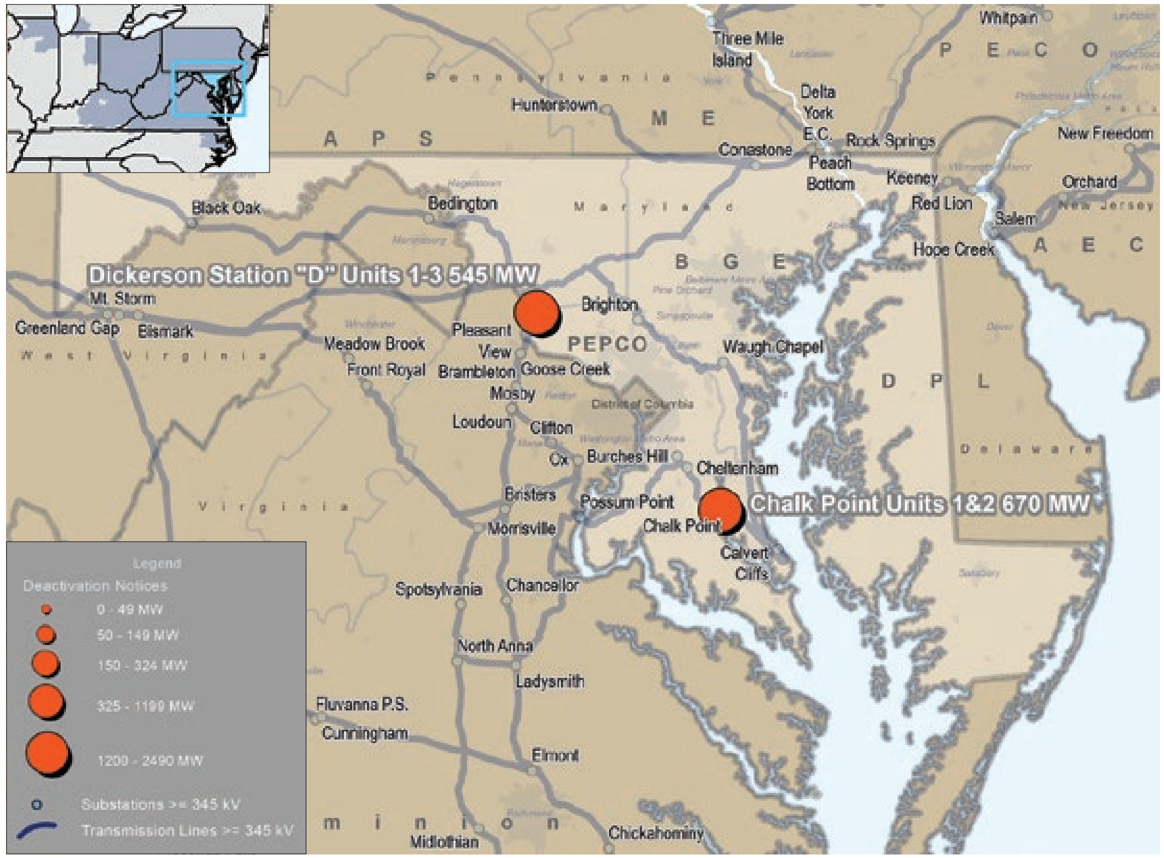


Table 6.20: Maryland/District of Columbia Generation Deactivations (Dec. 31, 2020)

Unit	TO Zone	Fuel Type	Request Submittal Date	Actual Deactivation Date	Age (Years)	Capacity (MW)
Dickerson Station Unit 1	PEPCO	Coal	5/15/2020	8/13/2020	61	182.0
Dickerson Station Unit 2			5/15/2020	8/13/2020	60	180.0
Dickerson Station Unit 3			5/15/2020	8/13/2020	58	180.5
Chalk Point Unit 1			8/10/2020	6/1/2021	56	333.1
Chalk Point Unit 2			8/10/2020	6/1/2021	55	337.2

6.4.6 — Baseline Projects

2020 RTEP baseline projects greater than or equal to $10 million in Maryland and the District of Columbia are summarized in **Map 6.16** and **Table 6.21**.

6.4.7 — Network Projects

No network projects greater than or equal to $10 million in Maryland and the District of Columbia were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.16: Maryland/District of Columbia Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

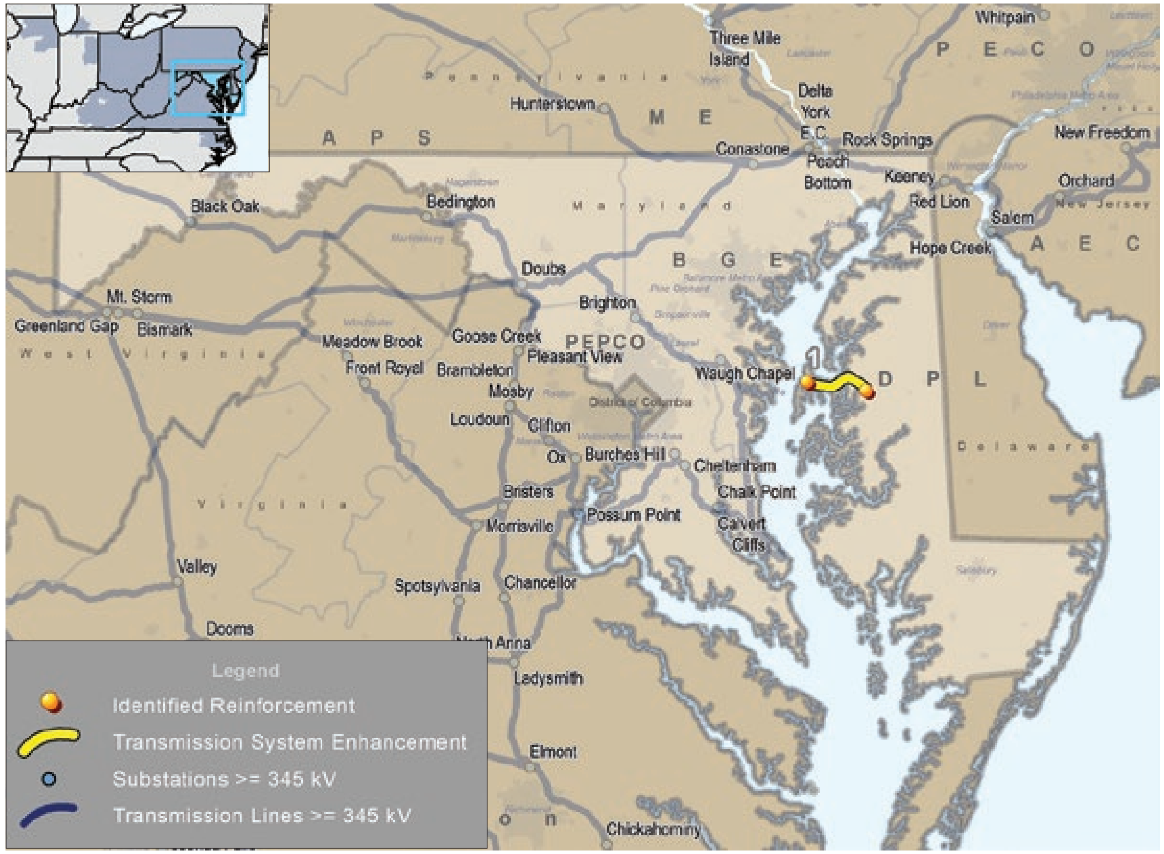


Table 6.21: Maryland/District of Columbia Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3155	Rebuild ~12 miles of Wye Mills-Stevensville line to achieve needed ampacity.	12/1/2023	$15.00	DP&L	12/16/2019

6.4.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in Maryland and the District of Columbia are summarized in **Map 6.17** and **Table 6.22**.

6.4.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in Maryland and the District of Columbia were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.17: Maryland/District of Columbia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

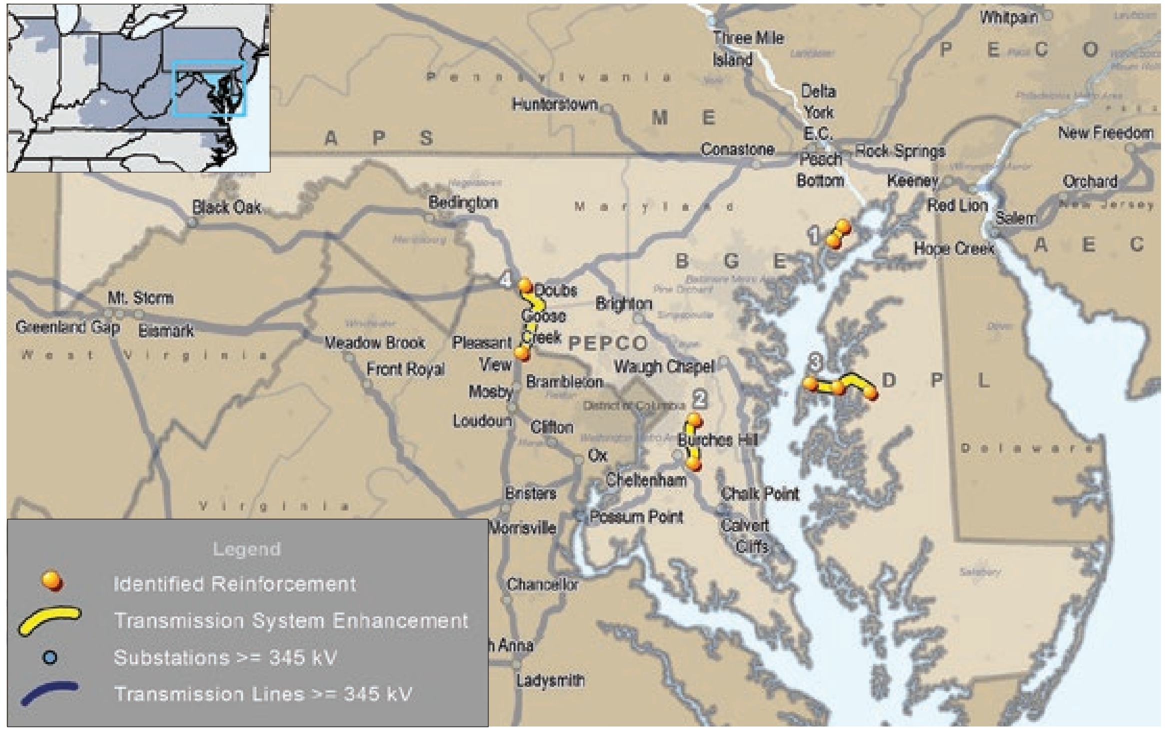


Table 6.22: Maryland/District of Columbia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2209	Rebuild two single-circuit 115 kV wood H-frame circuits (110617/110618) as one double-circuit steel-pole line.	12/31/2021	$21.40	BGE	3/20/2020
2	S2356	Rebuild 10 miles of existing Talbert-Oak Grove 230 kV double-circuit lattice tower transmission lines 23067 and 23087 with new steel monopole structures along the existing route.	12/1/2024	$38.00	PEPCO	9/1/2020
3	S2378	Construct two 69 kV substations along the existing Wye Mills to Stevensville circuit and retire existing Grasonville substation. Construct new five-breaker ring bus substation west of existing Grasonville substation (w/30 MVAR Capacitor Bank). Construct new five-breaker ring bus substation west of existing Wye Mills substation (w/30 MVAR Capacitor Bank).	6/1/2023	$18.50	DP&L	10/15/2020
4	S2386	Rebuild and reconductor the FE portion of the Doubs-Goose Creek 500 kV line (~14.8 miles of steel lattice tower construction) utilizing existing right-of-way. Replace breaker disconnect switches, line metering and relaying, substation conductor and breakers at Doubs 500 kV station.	6/1/2025	$60.00	AP	10/6/2020

6.5: Southwestern Michigan RTEP Summary

6.5.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Southwestern Michigan, including facilities owned and operated by American Electric Power (AEP) and International Transmission Co. (ITC) as shown on **Map 6.18**. Southwestern Michigan's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Renewable Portfolio Standards

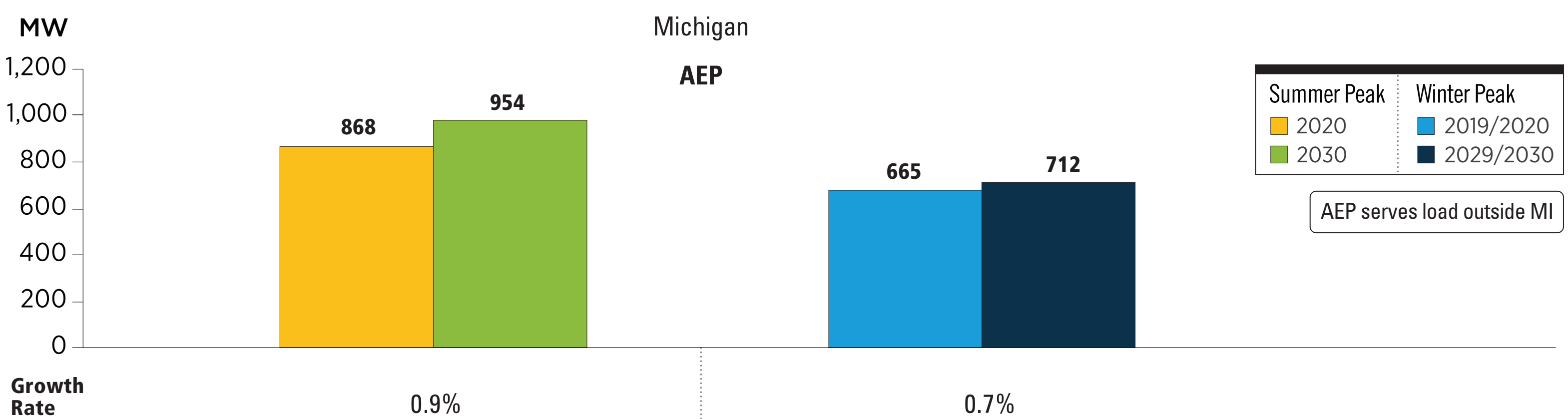
From an energy policy perspective, Michigan has a renewable portfolio standard (RPS) to advance renewable generation. Many states have instituted goals with respect to the percentage of generation expected to be fueled by renewable fuels in coming years. Michigan has a mandatory RPS target of 15 percent by 2021.

Map 6.18: PJM Service Area in Southwestern Michigan

6.5.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.26** summarizes the expected loads within the state of Michigan and across all of PJM.

Figure 6.26: Southwestern Michigan – 2020 Load Forecast Report



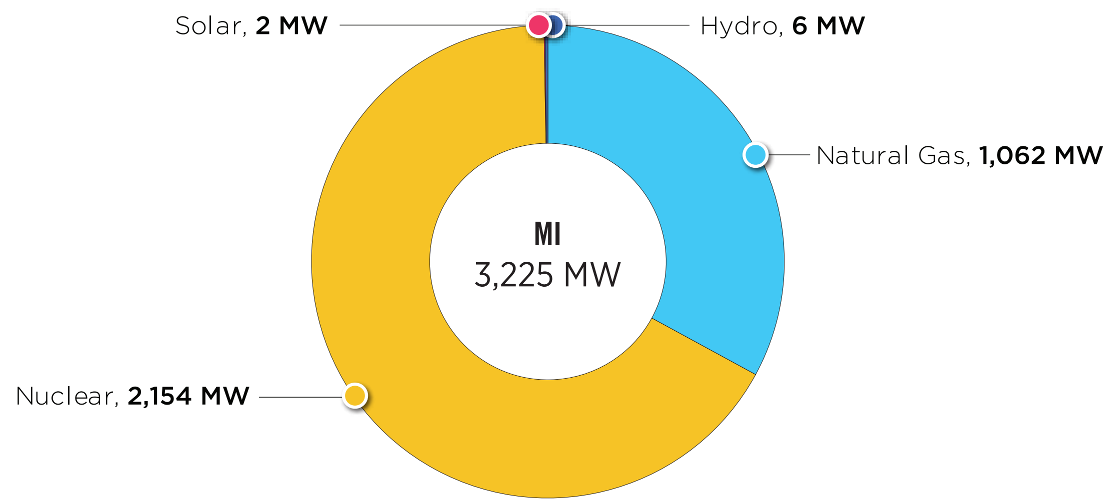
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.5.3 — Existing Generation

Existing generation in Southwestern Michigan as of Dec. 31, 2020, is shown by fuel type in **Figure 6.27**.

Figure 6.27: Southwestern Michigan – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



6.5.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Southwestern Michigan, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in Southwestern Michigan, as of Dec. 31, 2020, 13 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.23**, **Table 6.24**, **Figure 6.28, Figure 6.29** and **Figure 6.30**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.23: Southwestern Michigan – Capacity by Fuel Type – Interconnection Requests (Dec. 31. 2020)

	Southwestern Michigan Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	0	0.00%	559	0.53%
Natural Gas	1,230	61.62%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	0	0.00%	31	0.03%
Solar	685	34.30%	58,845	56.13%
Storage	81	4.07%	10,877	10.38%
Wind	0	0.00%	6,560	6.26%
Grand Total	**1,996**	**100.00%**	**104,838**	**100.00%**

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Table 6.24: Southwestern Michigan – Interconnection Requests by Fuel Type (Dec. 31 2020)

		In Queue				Complete				Grand Total	
		Active		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Natural Gas	1	145.0	2	1,085.0	2	1,055.0	1	1,120.0	6	3,405.0
	Nuclear	0	0.0	0	0.0	3	205.0	0	0.0	3	205.0
	Other	0	0.0	0	0.0	0	0	1	0.0	1	0.0
	Storage	3	81.3	0	0.0	0	0	1	75.0	4	156.3
Renewable	Methane	0	0.0	0	0.0	3	10.4	0	0.0	3	10.4
	Solar	7	684.8	0	0.0	1	2.3	4	237.8	12	924.8
	Wind	0	0.0	0	0.0	0	0	1	26.0	1	26.0
	Grand Total	11	911.1	2	1,085.0	9	1,272.7	8	1,458.8	30	4,727.5

Figure 6.28: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

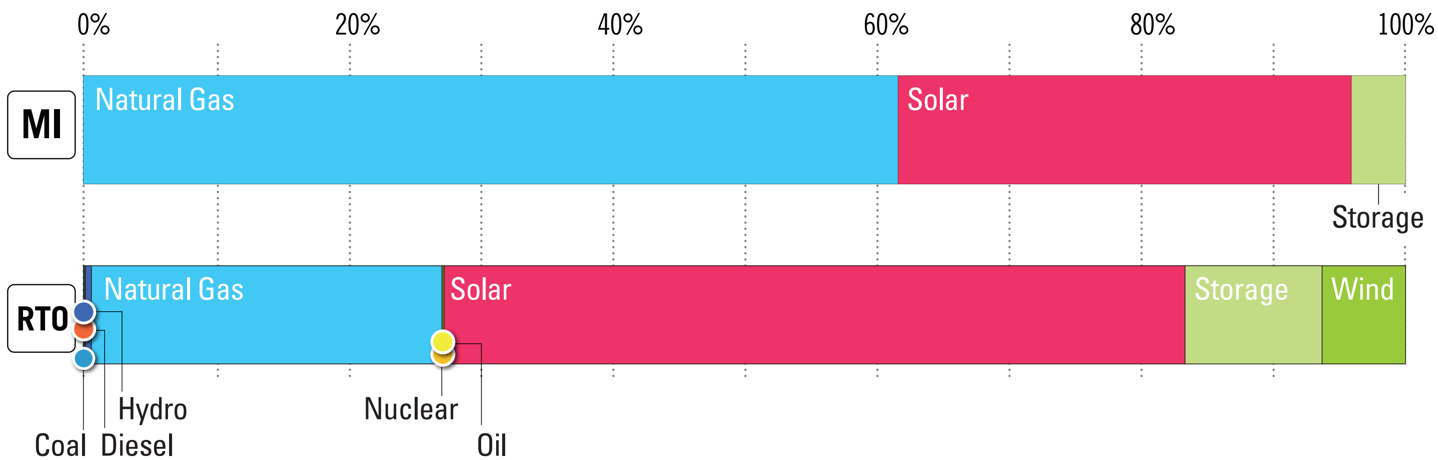

Figure 6.29: Southwestern Michigan – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)

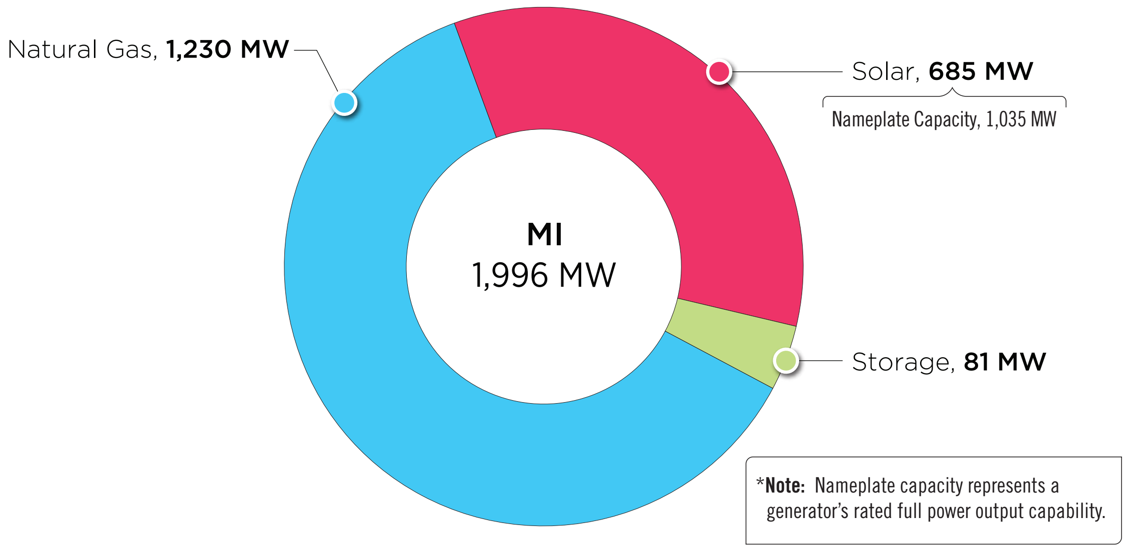

Figure 6.30: Southwestern Michigan Progression History of Queue – Interconnection Requests (Dec. 31, 2020)

Percentage of planned capacity and projects that have reached commercial operation	33% Requested capacity megawatts	47 % Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2020.

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6.5.5 — Generation Deactivations

There were no known generating unit deactivation requests in Southwestern Michigan between Jan. 1, 2020, and Dec. 31, 2020, as part of the 2020 RTEP.

6.5.6 — Baseline Projects

2020 RTEP baseline projects greater than or equal to $10 million in Southwestern Michigan are summarized in **Map 6.19** and **Table 6.25**.

6.5.7 — Network Projects

No network projects greater than or equal to $10 million in Southwestern Michigan were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.19: Southwestern Michigan Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

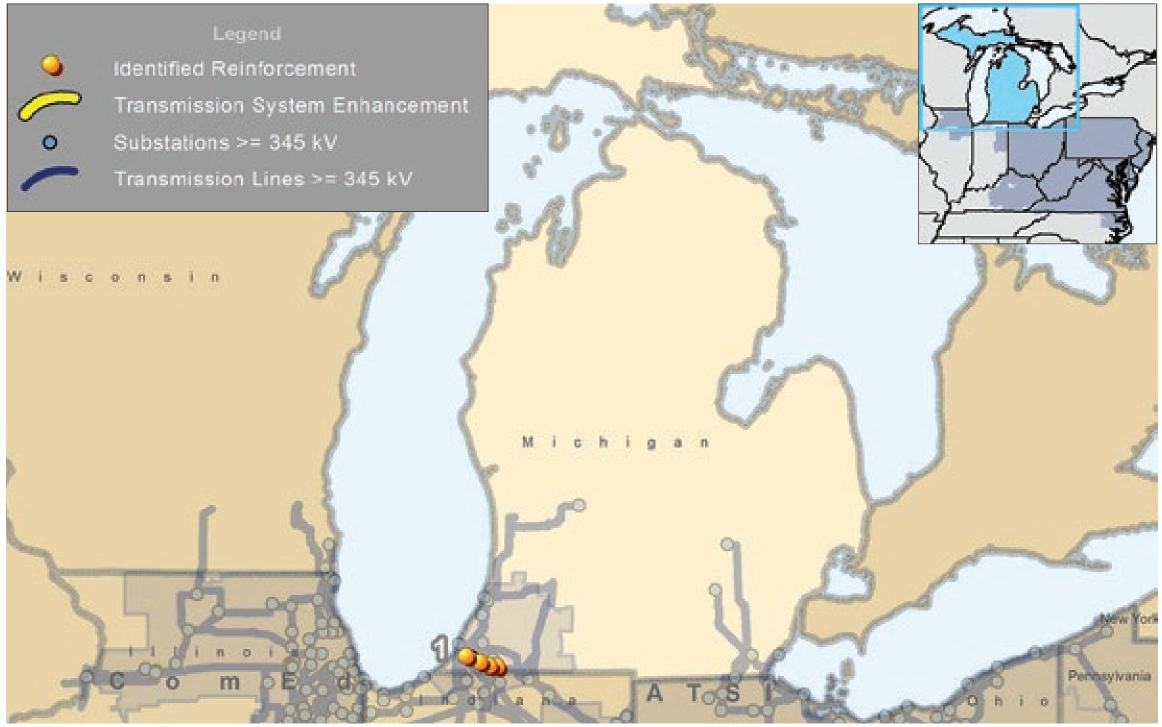


Table 6.25: Southwestern Michigan Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3160	Construct a ~2.4 mile double-circuit 138 kV extension using 1033 ACSR to connect Lake Head to the 138 kV network.	6/1/2024	$36.20	AEP	12/7/2019
		Retire the ~2.5 mile 34.5 kV Niles-Simplicity tap line.				
		Retire the ~4.6 mile Lakehead 69 kV tap.				
		Build a new 138/69 kV drop down station to feed Lakehead with a 138 kV breaker, 138 kV switcher, 138/69 kV transformer and a 138 kV MOAB.				
		Rebuild the ~1.2 mile Buchanan South 69 kV radial tap using 795 ACSR.				
		Rebuild the ~8.4 mile 69 kV Pletcher-Buchanan Hydro line as the ~9 mile Pletcher-Buchanan South 69 kV line using 795 ACSR.				
		Install a phase-over-phase switch at Buchanan South station with two-line MOABs.				

6.5.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in Southwestern Michigan are summarized in **Map 6.20** and **Table 6.26**.

6.5.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in Southwestern Michigan were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.20: Southwestern Michigan Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

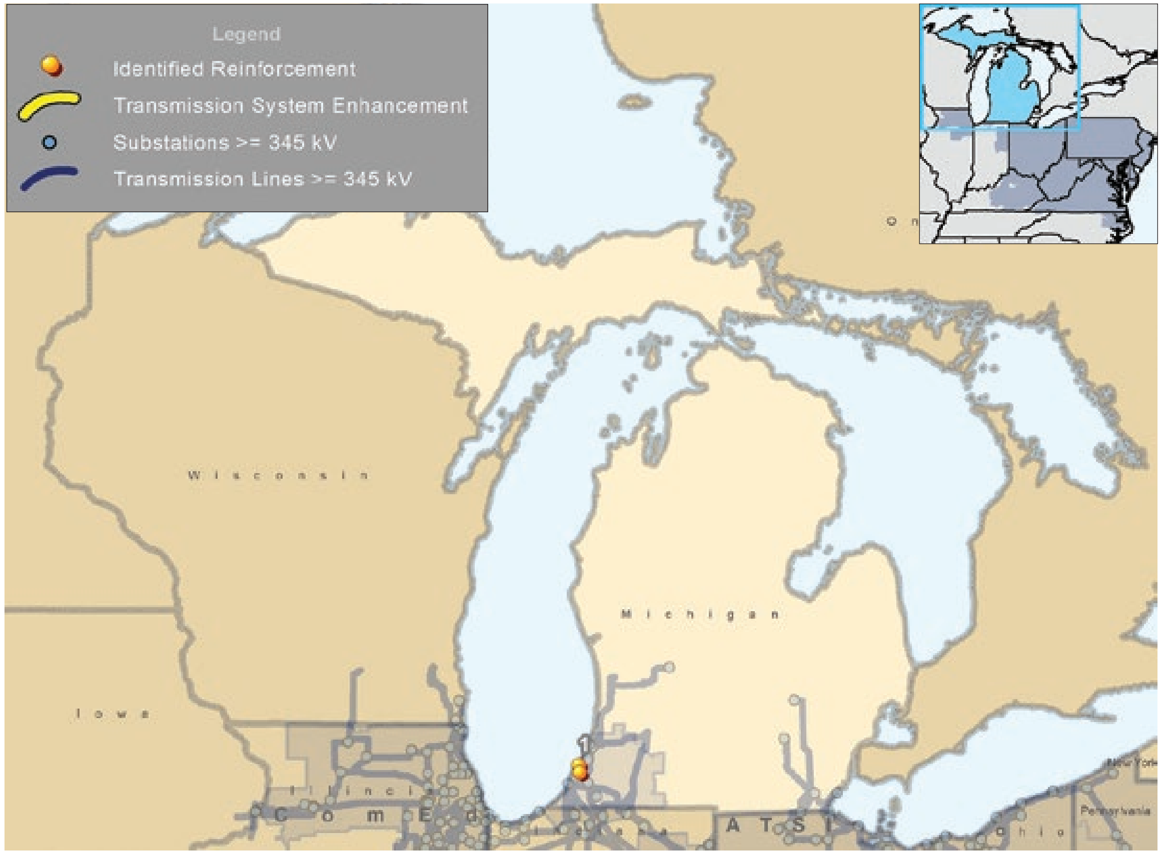


Table 6.26: Southwestern Michigan Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2345	Main St.-Riverside 34.5 kV line: Rebuild on center line ~4.1 miles of Main St.-Riverside 34.5 kV line with DOVE 556.5 ACSR 26/7.	2/14/2024	$16.60	AEP	7/17/2020
		Riverside Station: Replace two 138 kV breakers and two 34.5 kV breakers at Riverside. While at the station and taking advantage of the outage, AEP will install a new 34.5 kV breaker to bring Whirlpool customer, whose delivery point is currently one tower outside of the station, into Riverside station. Install high-side circuit switcher to 138/69/34.5 kV transformer.				

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

6.6: New Jersey RTEP Summary

6.6.1 — RTEP Context

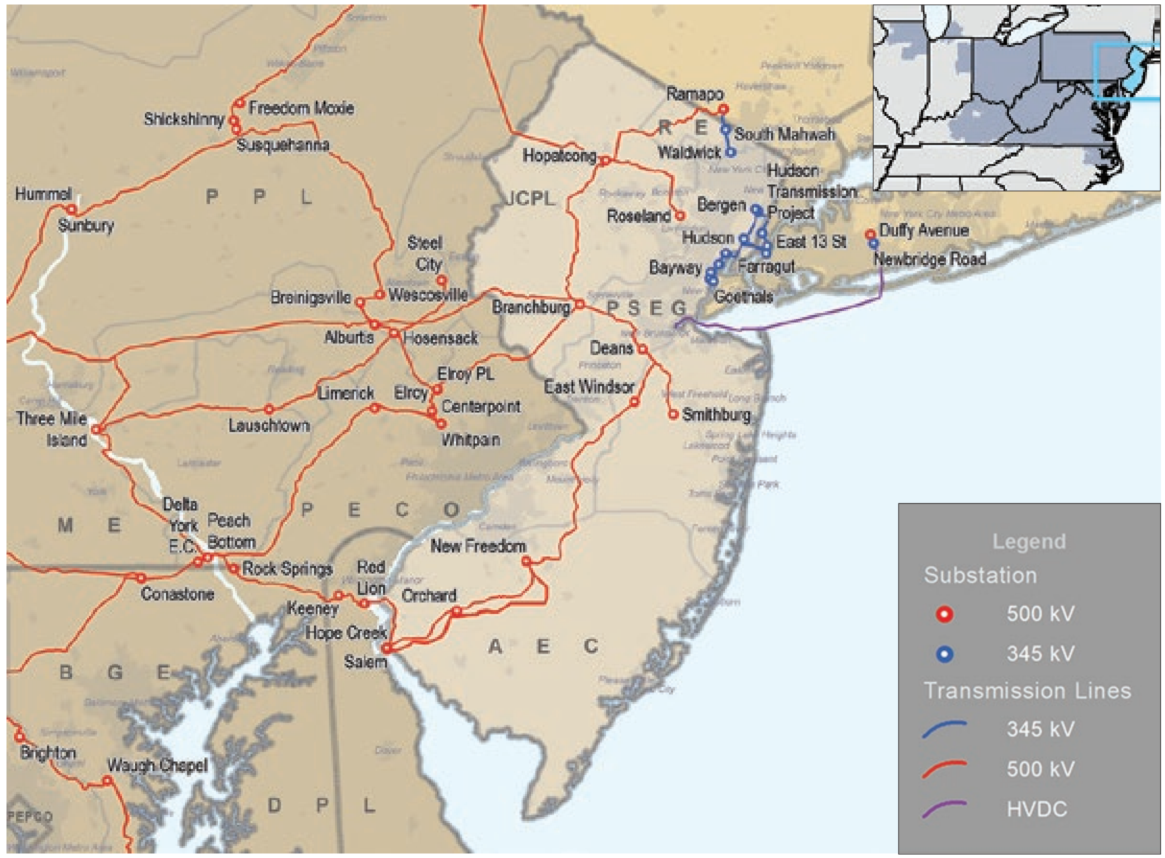
PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in New Jersey, including facilities owned and operated by Atlantic City Electric Co. (AE), Jersey Central Power & Light (JCP&L), Linden VFT (VFT), Neptune Regional Transmission System (Neptune RTS), PSEG and Rockland Electric Co. (RECO), as shown on **Map 6.21**. New Jersey's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Renewable Portfolio Standards

From an energy policy perspective, New Jersey has a renewable portfolio standard (RPS) to advance renewable generation. Many states have instituted goals with respect to the percentage of generation expected to be fueled by renewable fuels in coming years.

New Jersey has a mandatory RPS target of 50 percent Class I renewable resources by 2030. The state also requires 2.5 percent Class II renewable resources each year. The RPS contains a solar carve-out that peaks at 5.1 percent in 2023 and declines each year thereafter.

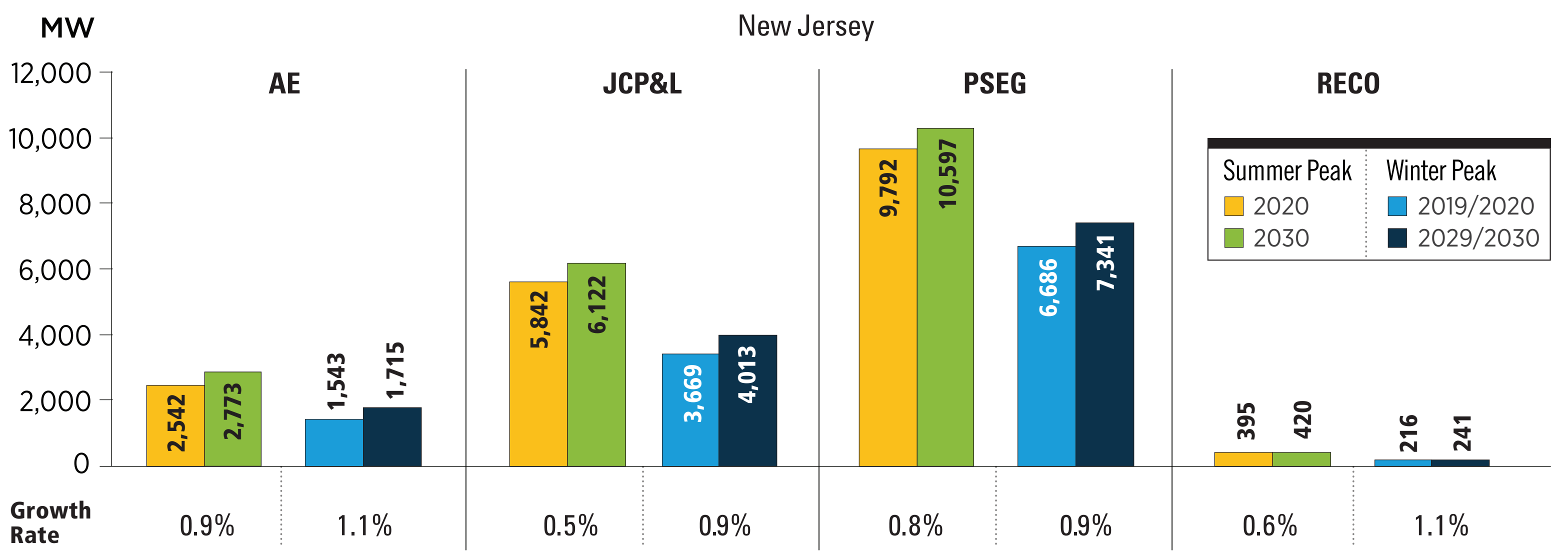
Map 6.21: PJM Service Area in New Jersey



6.6.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.31** summarizes the expected loads within the state of New Jersey and across all of PJM.

Figure 6.31: New Jersey – 2020 Load Forecast Report



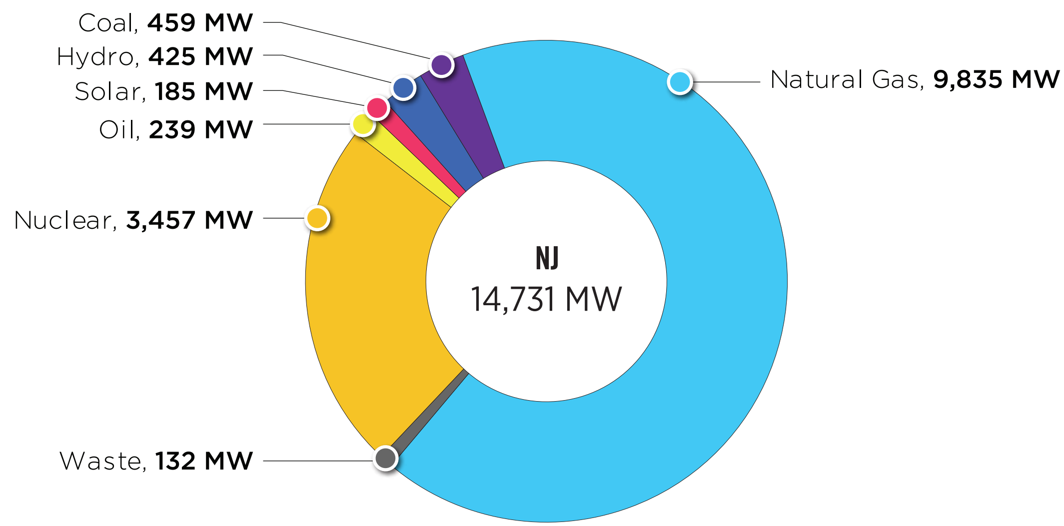
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and

6.6.3 — Existing Generation

Existing generation in New Jersey as of Dec. 31, 2020, is shown by fuel type in **Figure 6.32**.

Figure 6.32: New Jersey – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



6.6.4 — Interconnection Requests

PJM markets continue to attract generation proposals in New Jersey, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in New Jersey, as of Dec. 31, 2020, 135 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.27**, **Table 6.28**, **Figure 6.33**, **Figure 6.34**, and **Figure 6.35**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.27: New Jersey – Capacity by Fuel Type – Interconnection Requests (Dec. 31. 2020)

	New Jersey Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	0	0.00%	559	0.53%
Natural Gas	1,178	21.69%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	0	0.00%	31	0.03%
Solar	724	13.35%	58,845	56.13%
Storage	1,283	23.64%	10,877	10.38%
Wind	2,243	41.32%	6,560	6.26%
Grand Total	**5,428**	**100.00%**	**104,838**	**100.00%**

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Table 6.28: New Jersey – Interconnection Requests by Fuel Type (Dec. 31 2020)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	0	0.0	1	15.0	1	15.0
	Natural Gas	6	372.3	2	746.0	2	59.2	80	8,017.9	179	51,724.3	269	60,919.7
	Nuclear	0	0.0	0	0.0	0	0.0	6	381.0	0	0.0	6	381.0
	Oil	0	0.0	0	0.0	0	0.0	2	35.0	8	945.0	10	980.0
	Other	0	0.0	0	0.0	0	0.0	0	0.0	7	45.5	7	45.5
	Storage	39	1,283.2	4	0.0	3	0.0	6	4.0	44	214.0	96	1,501.1
Renewable	Biomass	0	0	0	0.0	0	0.0	0	0.0	3	17.3	3	17.3
	Hydro	0	0	0	0.0	0	0.0	2	20.5	2	1,001.1	4	1,021.6
	Methane	0	0	0	0.0	0	0.0	16	45.3	9	40.6	25	85.9
	Solar	46	692.6	1	4.1	19	27.7	114	248.2	480	1,609.6	660	2,582.3
	Wind	13	2,242.9	0	0	0	0.0	1	0.0	20	683.3	34	2,926.2
	Grand Total	104	4,590.9	7	750.1	24	86.9	227	8,751.9	753	56,295.8	1,115	70,475.6

Figure 6.33: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

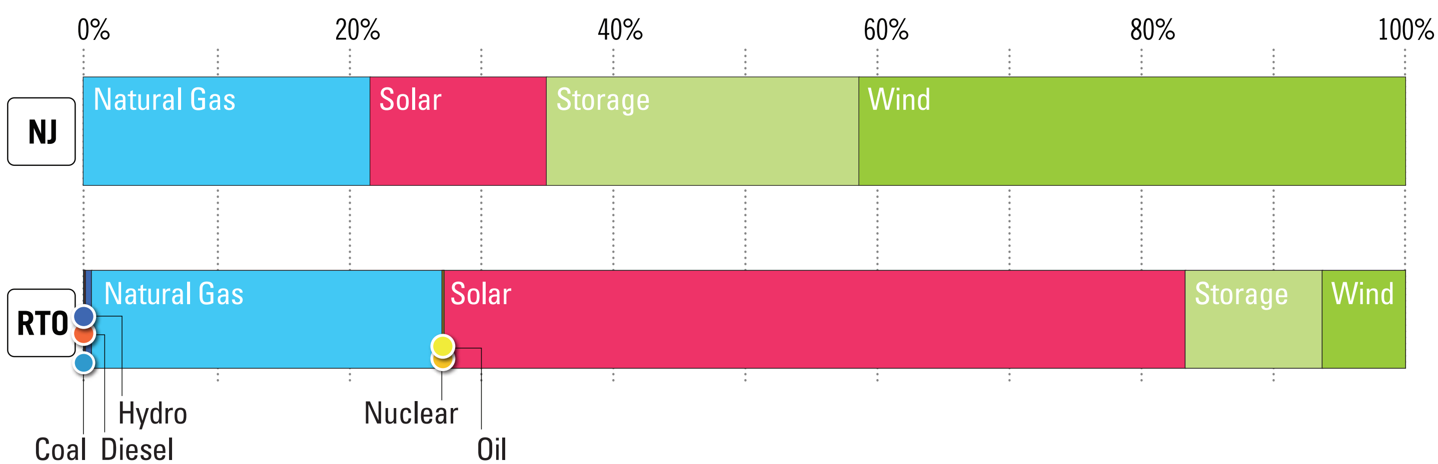


Figure 6.34: New Jersey – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)

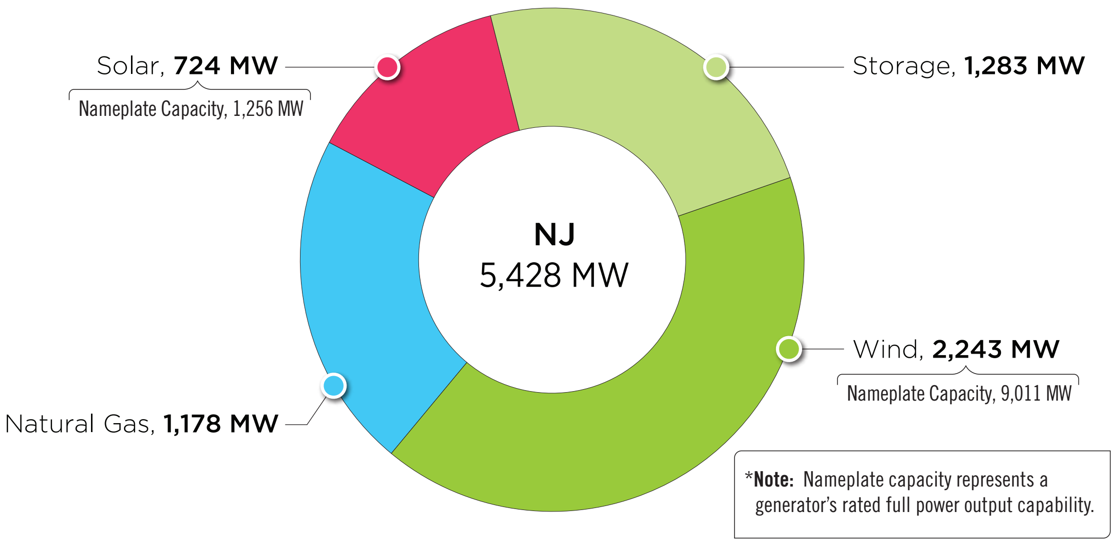
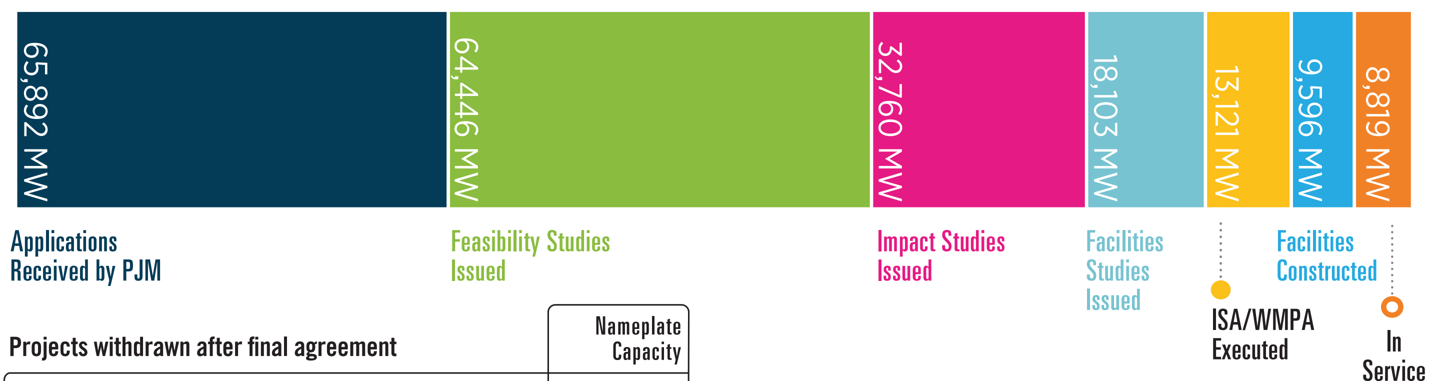


Figure 6.35: New Jersey Progression History of Queue – Interconnection Requests (Dec. 31, 2020)



Projects withdrawn after final agreement

			Nameplate Capacity
24	Interconnection Service Agreements	**2,595** MW	3,067 MW
146	Wholesale Market Participation Agreements	**376** MW	1,073 MW

Percentage of planned capacity and projects that have reached commercial operation	**13%** Requested capacity megawatts	**24%** Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2020.

6.6.5 — Generation Deactivation

Known generating unit deactivation requests in New Jersey between Jan. 1, 2020, and Dec. 31, 2020, are summarized in **Map 6.22** and **Table 6.29**.

Map 6.22: New Jersey Generation Deactivations (Dec. 31, 2020)

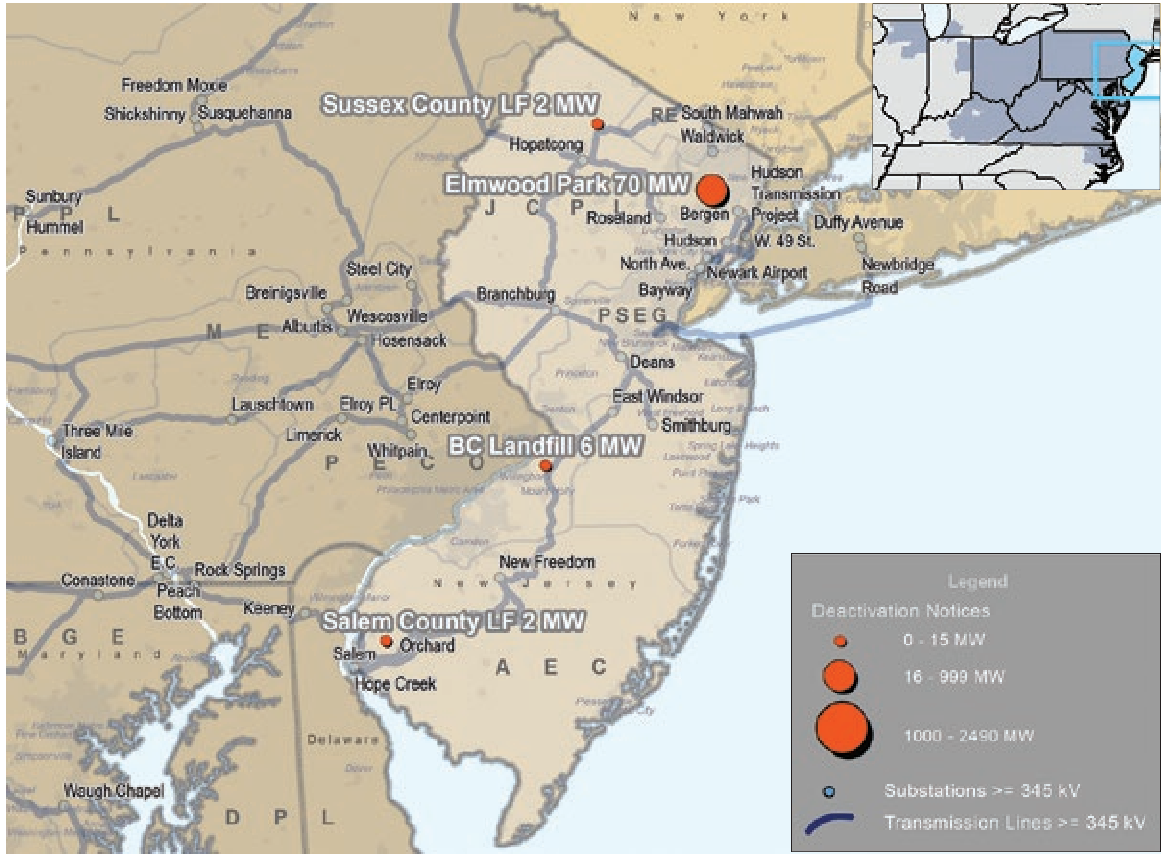


Table 6.29: New Jersey Generation Deactivations (Dec. 31, 2020)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
BC Landfill	PSEG	Methane	1/27/2020	6/1/2020	13	6.00
Salem County LF	AE	Methane	1/27/2020	6/1/2020	12	1.70
Sussex County LF	JCP&L	Methane	1/27/2020	6/1/2020	9	2.00
Elmwood Park	PSEG	Natural Gas	12/8/2020	3/12/2021	31	70.30

6.6.6 — Baseline Projects

No baseline projects greater than or equal to $10 million in New Jersey were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.6.7 — Network Projects

No network projects greater than or equal to $10 million in New Jersey were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.6.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in New Jersey are summarized in **Map 6.23** and **Table 6.30**.

Map 6.23: New Jersey Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

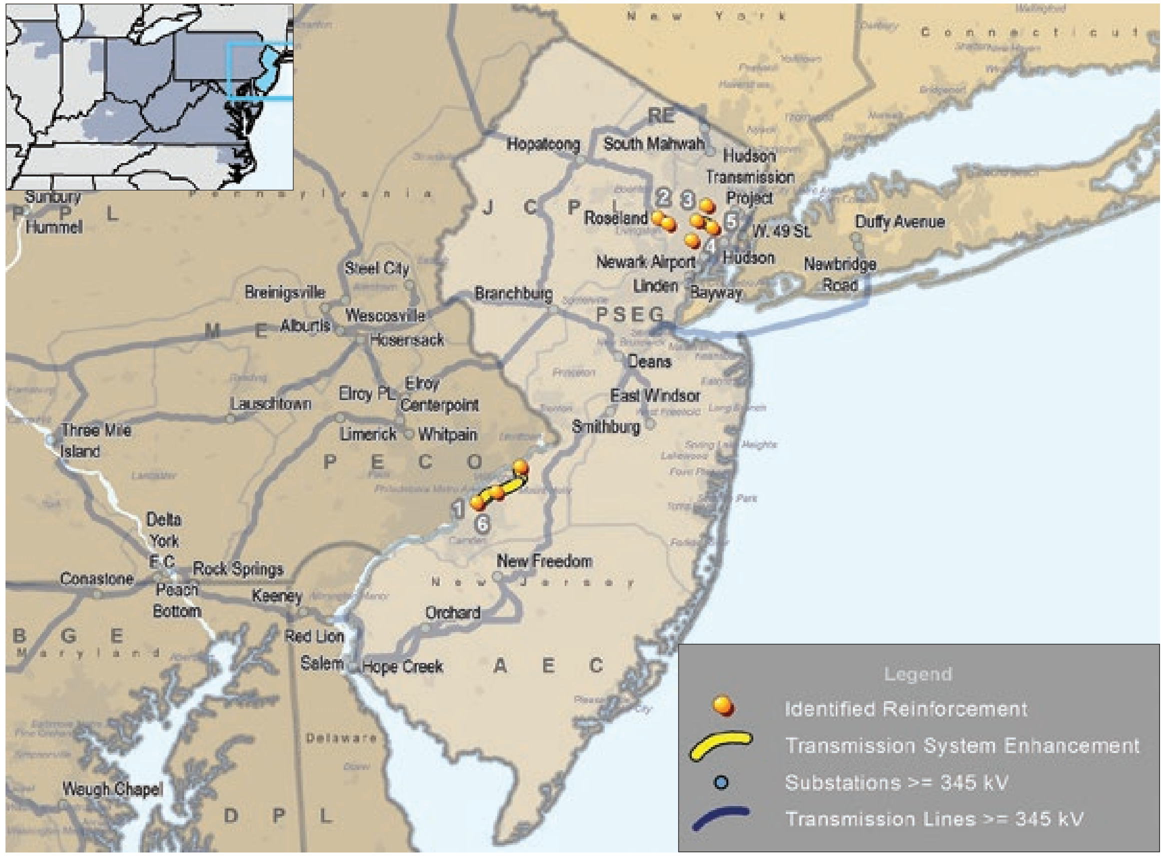


Table 6.30: New Jersey Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2276	Install a new 230/13 kV station (Rancocas) on existing right-of-way with two 230/13kV transformers. Cut and loop the Camden-Burlington 230 kV line in to the 230 kV bus.	5/31/2024	$39.00	PSEG	6/2/2020
2	S2316	Install Livingston 230 kV station with two 230/13 kV transformers. Cut and loop the Roseland-Laurel Ave 230 kV line into the 230 kV bus. Transfer load from heavily loaded Marion Drive and West Caldwell to the new station.	12/31/2024	$29.80		8/4/2020

Table 6.30: New Jersey Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	S2317	Construct a new Oak St. 69/13 kV station in Southern Passaic County Area and retire the Oak St. 26 kV station.	9/30/2024	$75.60	PSEG	8/13/2020
		Purchase property to accommodate the new Oak St. 69/13 kV construction.				
		Install Oak St. 69 kV station with two 69/13 kV transformers.				
		Loop in the existing Kuller Rd.-Passaic 69 kV to the new Oak St. and build a new 69 kV line from Harvey to Oak St.				
4	S2318	Construct a new Central Ave. 69/4 kV station in Western Newark area.	5/31/2024	$34.30		
		Purchase property to accommodate the new Central Ave. 69/4 kV station construction.				
		Install a Central Ave. 69 kV station with four 69/4 kV transformers.				
		Loop in the existing McCarter-Clay Street and McCarter-Orange Heights 69 kV circuits to the new Central Ave. 69 kV station.				
5	S2384	Construct new 230-13 kV station along the existing right-of-way at Washington Ave. Cut and loop the Cook Rd.-Kingsland 230 kV line into the new 230 kV bus (Washington Ave.), and Install a 230 kV bus station with two 230/13 kV transformers. Transfer load from heavily loaded Cook Rd. to the new station.		$31.20		10/6/2020
6	S2385	Construct new 230-13 kV station along the existing right-of-way in Pennsauken. Cut and loop the Camden-Cinnaminson 230 kV line into the new 230 kV bus (Pennsauken), and install a 230 kV station with two 230/13 kV transformers. Transfer load from heavily loaded Cuthbert Blvd. to the new station.		$48.60		

6.6.9 — Merchant Transmission Project Requests

As of Dec. 31, 2020, PJM's queue contained five merchant transmission project requests, which include a terminal in New Jersey as shown in **Map 6.24** and **Table 6.31**.

Map 6.24: New Jersey Merchant Transmission Project Requests (Dec. 31, 2020)

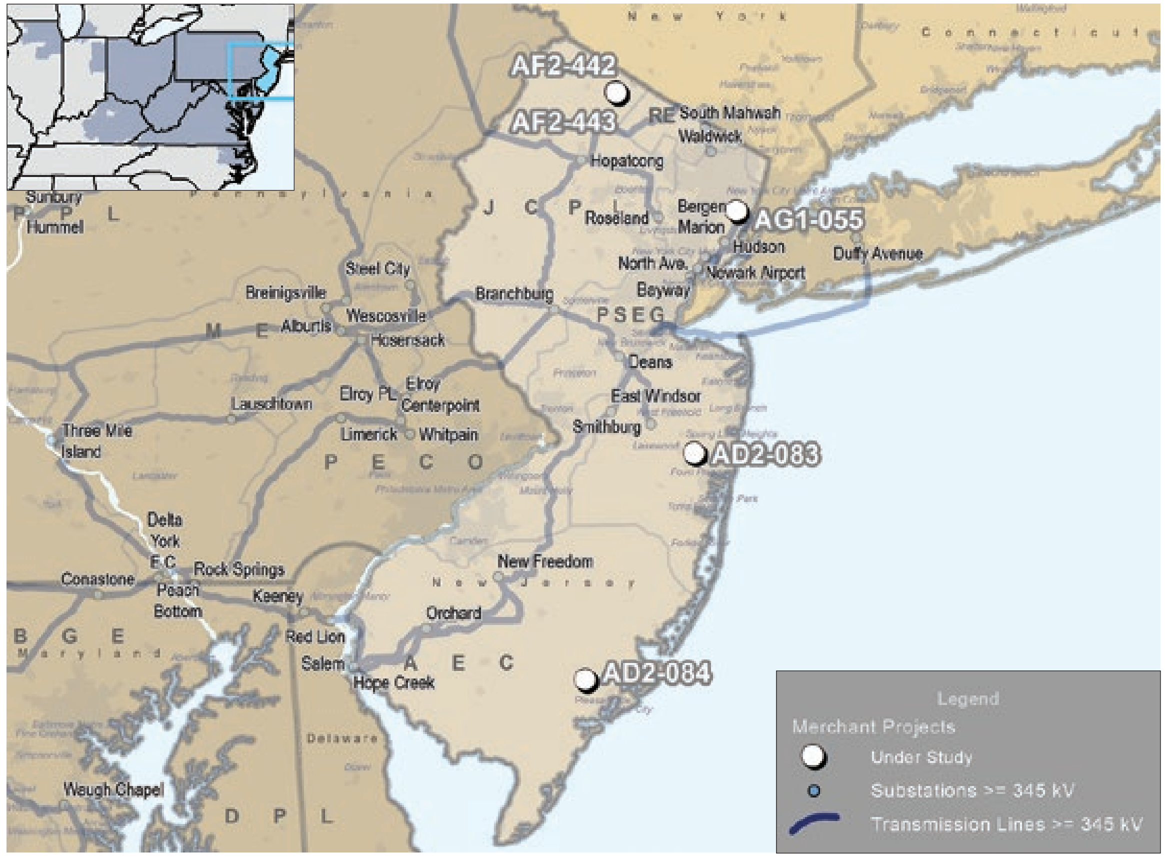


Table 6.31: New Jersey Merchant Transmission Project Requests (Dec. 31, 2020)

Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
AD2-083	Larrabee 230 kV	JCP&L	Active	12/31/2025	1,100
AD2-084	Cardiff 230 kV	AE	Active		1,100
AF2-442	Vernon 115 kV	JCP&L	Active	5/31/2023	84
AF2-443	Vernon 115 kV		Active		84
AG1-055	Bergen 230 kV	PSEG	Active	6/1/2022	660

6.7: North Carolina RTEP Summary

6.7.1 — RTEP Context

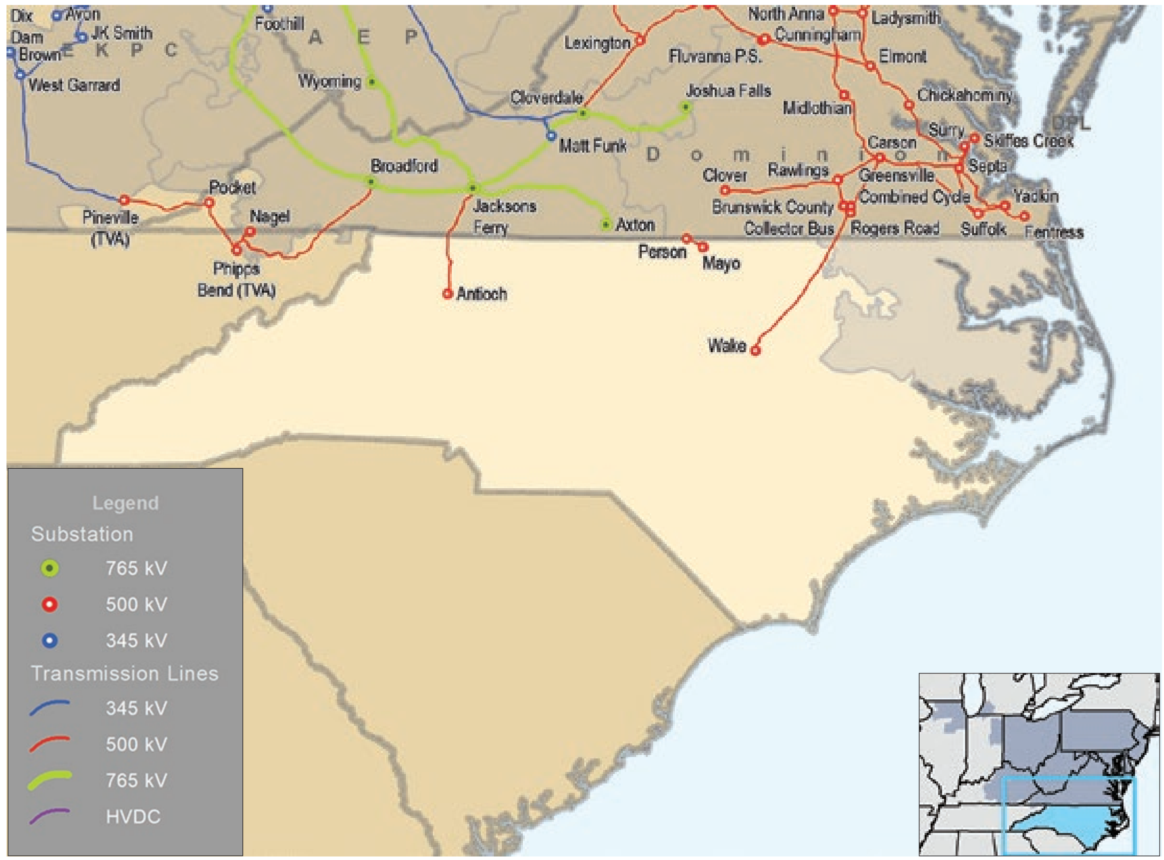
PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in North Carolina, including facilities owned and operated by Dominion as shown on **Map 6.25**. North Carolina's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Renewable Portfolio Standards

From an energy policy perspective, North Carolina has a renewable portfolio standard (RPS) to advance renewable generation. Many states have instituted goals with respect to the percentage of generation expected to be fueled by renewable fuels in coming years.

North Carolina has a mandatory RPS target of 12.5 percent for investor-owned utilities by 2021. The target is 10 percent for the state's electric cooperatives and municipalities.

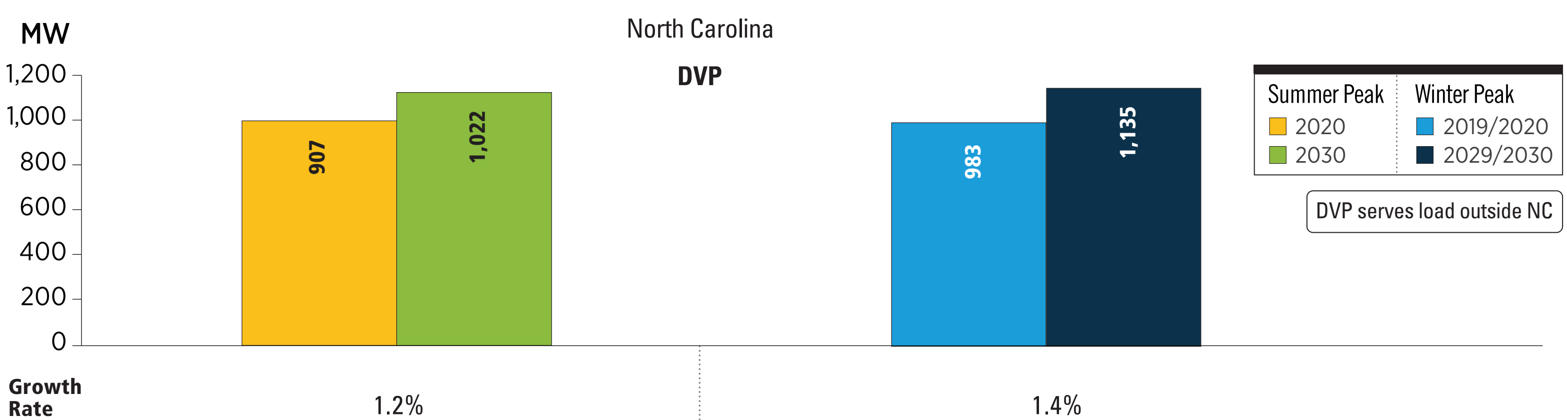
Map 6.25: PJM Service Area in North Carolina



6.7.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.36** summarizes the expected loads within the state of North Carolina and across all of PJM.

Figure 6.36: North Carolina – 2020 Load Forecast Report



PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

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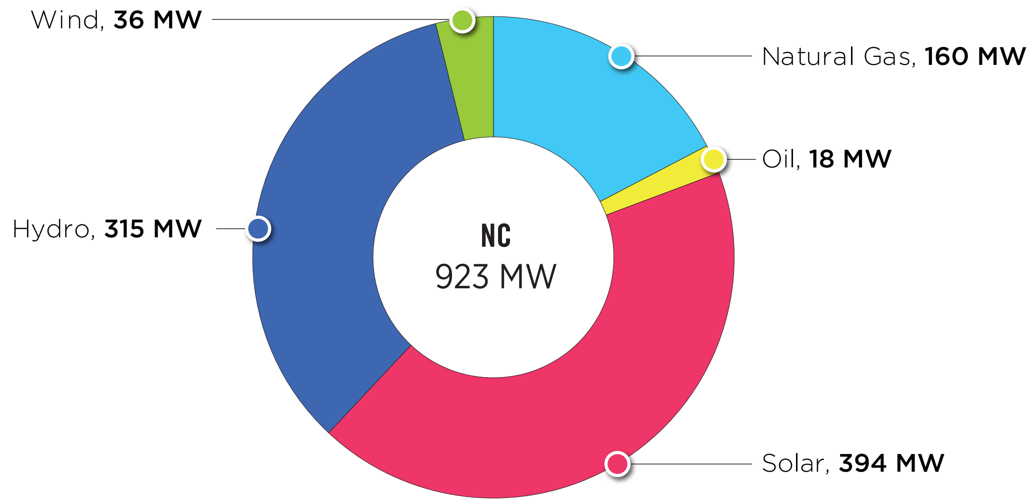
6.7.3 — Existing Generation

Existing generation in North Carolina as of Dec. 31, 2020, is shown by fuel type in **Figure 6.37**.

Figure 6.37: North Carolina – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



6.7.4 — Interconnection Requests

PJM markets continue to attract generation proposals in North Carolina, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in North Carolina, as of Dec. 31, 2020, 64 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.32**, **Table 6.33**, **Figure 6.38**, **Figure 6.39** and **Figure 6.40**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.32: North Carolina – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2020)

	North Carolina Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	0	0.00%	559	0.53%
Natural Gas	0	0.00%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	0	0.00%	31	0.03%
Solar	3,379	89.25%	58,845	56.13%
Storage	368	9.72%	10,877	10.38%
Wind	39	1.03%	6,560	6.26%
Grand Total	**3,786**	**100.00%**	**104,838**	**100.00%**

Table 6.33: North Carolina – Interconnection Requests by Fuel Type (Dec. 31, 2020)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Storage	6	368.0	0	0.0	0	0.0	0	0.0	5	130.5	11	498.5
Renewable	Methane	0	0.0	0	0.0	0	0.0	0	0.0	1	12.0	1	12.0
	Solar	44	2,905.1	2	87.5	11	386.8	17	465.1	83	3,166.5	157	7,011.0
	Wind	0	0.0	1	39.0	0	0.0	1	27.0	9	195.3	11	261.3
	Wood	0	0.0	0	0.0	0	0.0	1	50.0	1	80.0	2	130.0
	Grand Total	50	3,273.1	3	126.5	11	386.8	19	542.1	99	3,584.3	182	7,912.7

Figure 6.38: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

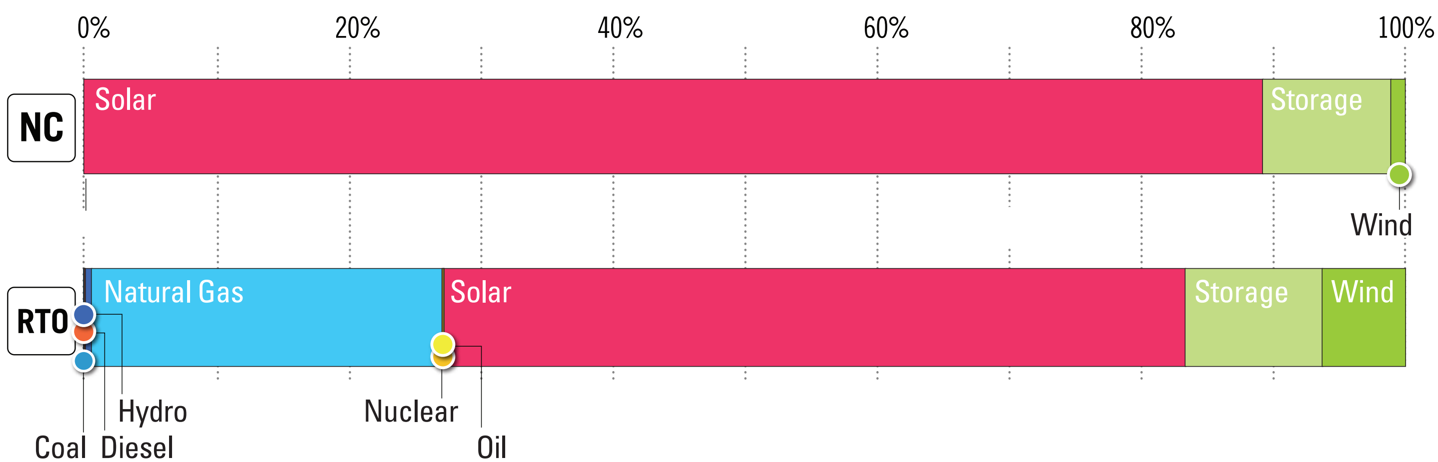
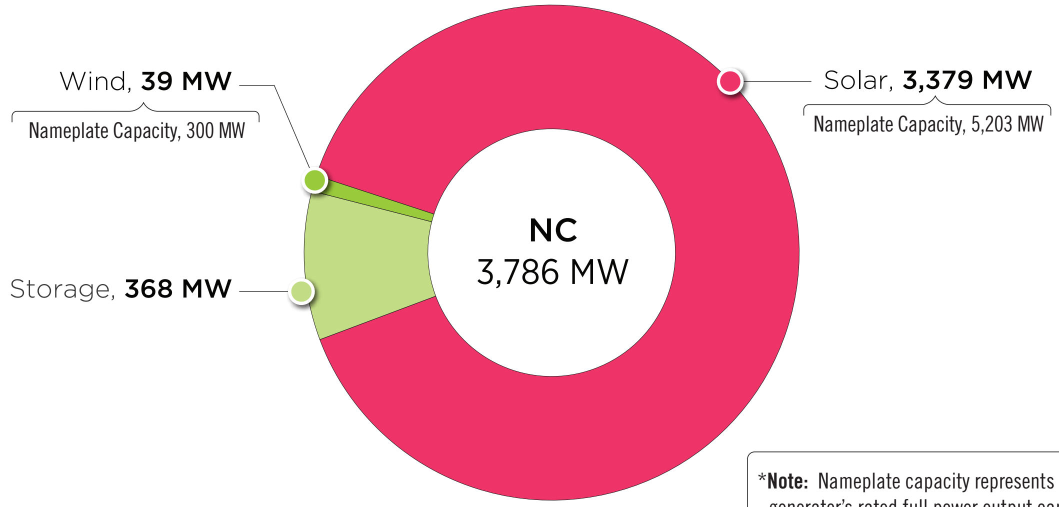
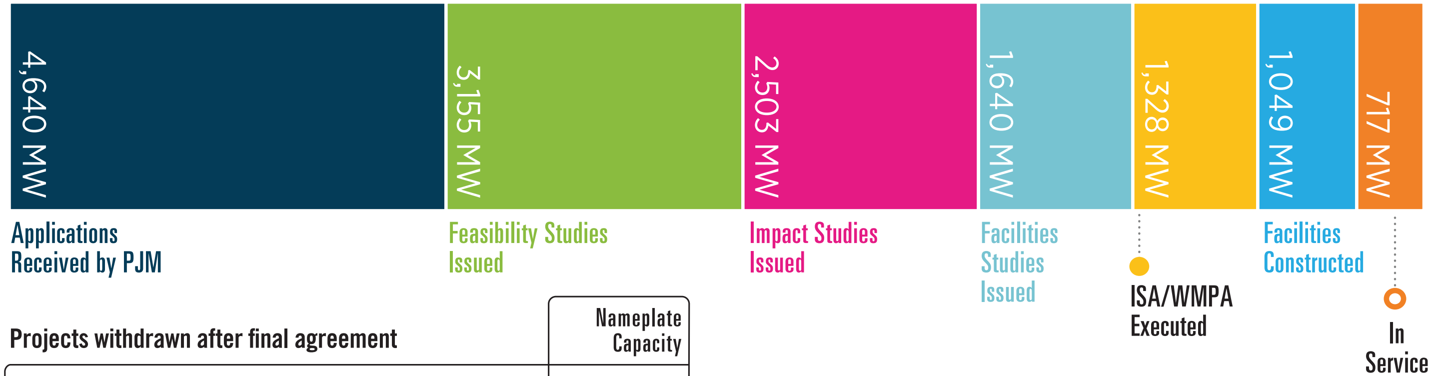


Figure 6.39: North Carolina – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)



*Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.40: North Carolina Progression History of Queue – Interconnection Requests (Dec. 31, 2020)



Projects withdrawn after final agreement

			Nameplate Capacity
7	Interconnection Service Agreements	235 MW	744 MW
4	Wholesale Market Participation Agreements	38 MW	55 MW

Percentage of planned capacity and projects that have reached commercial operation	15% Requested capacity megawatts	17 % Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2020.

6.7.5 — Generation Deactivation

There were no known generating unit deactivation requests in North Carolina between Jan. 1, 2020, and Dec. 31, 2020, as part of the 2020 RTEP.

6.7.6 — Baseline Projects

No baseline projects greater than or equal to $10 million in North Carolina were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.7.7 — Supplemental Projects

No supplemental projects greater than or equal to $10 million in North Carolina were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.7.8 — Network Projects

No network projects greater than or equal to $10 million in North Carolina were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.7.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in North Carolina were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.8: Ohio RTEP Summary

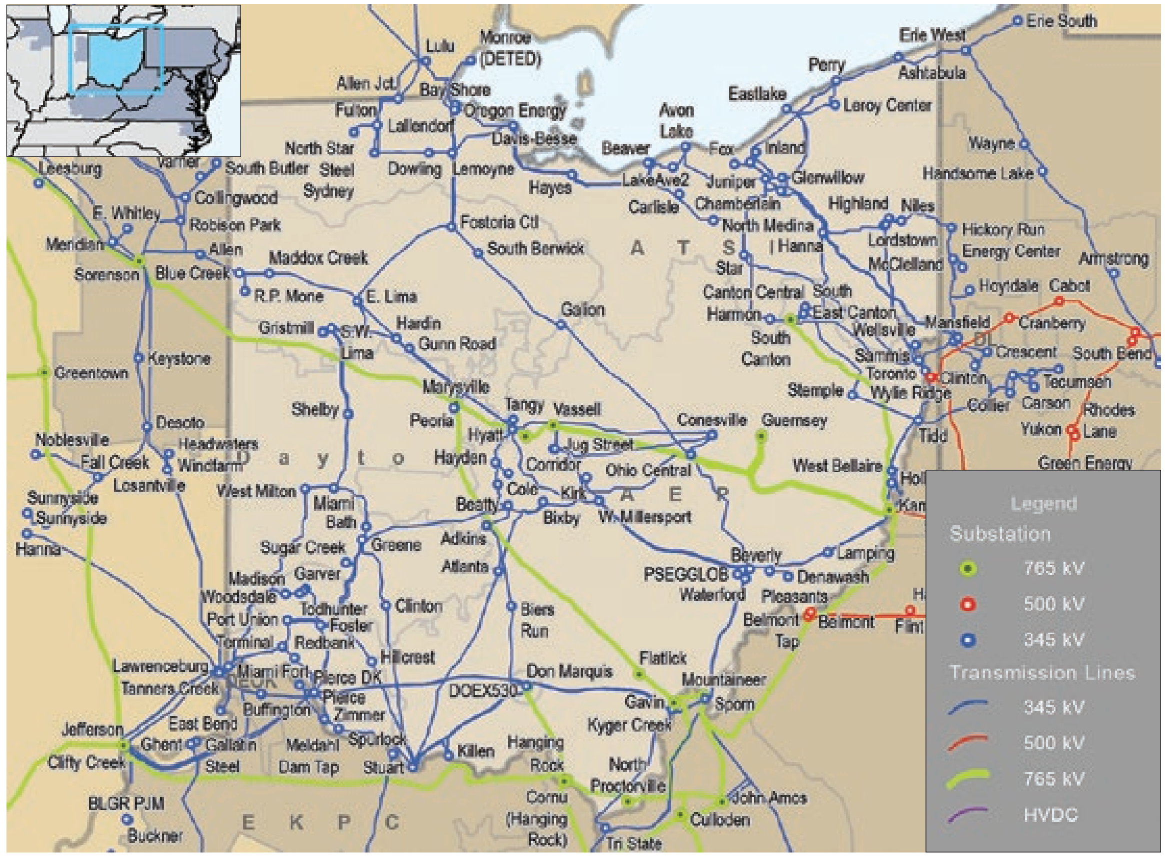
6.8.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Ohio, including facilities owned and operated by American Electric Power (AEP), Dayton Power & Light Co. (DAY), American Transmission Systems, Inc. (ATSI), Duke Energy Corp. (DEO&K), the City of Cleveland and the City of Hamilton as shown on **Map 6.26**. Ohio's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Renewable Portfolio Standards

From an energy policy perspective, Ohio has a renewable portfolio standard (RPS) to advance renewable generation. Many states have instituted goals with respect to the percentage of generation expected to be fueled by renewable fuels in coming years. Ohio has a mandatory RPS target of 8.5 percent by 2026.

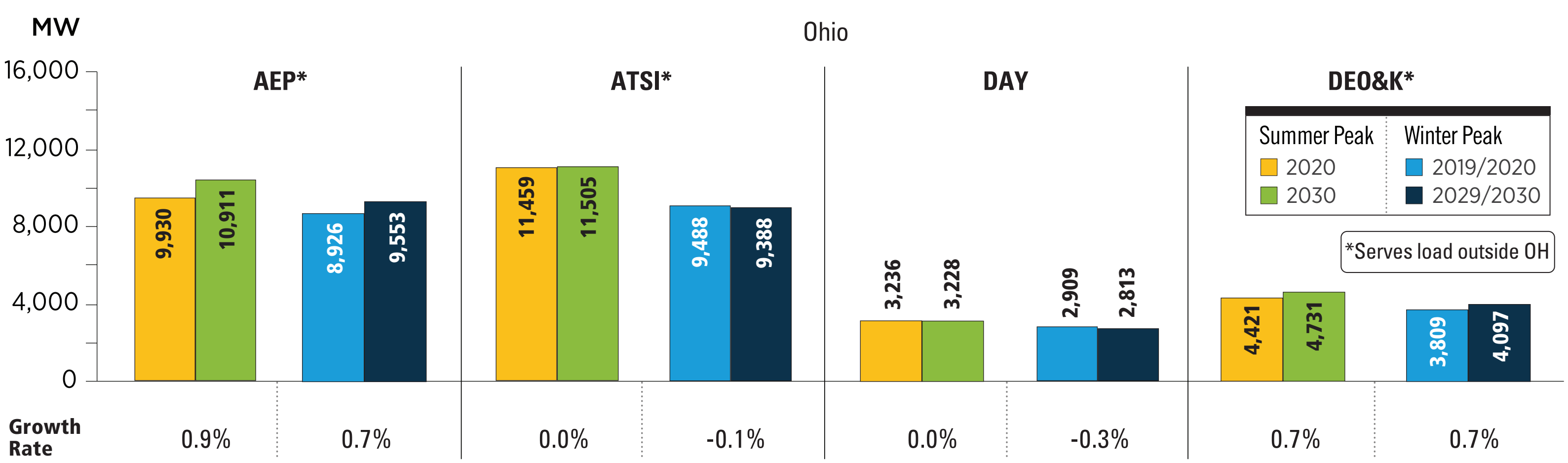
Map 6.26: PJM Service Area in Ohio



6.8.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.41** summarizes the expected loads within the state of Ohio and across all of PJM.

Figure 6.41: Ohio – 2020 Load Forecast Report



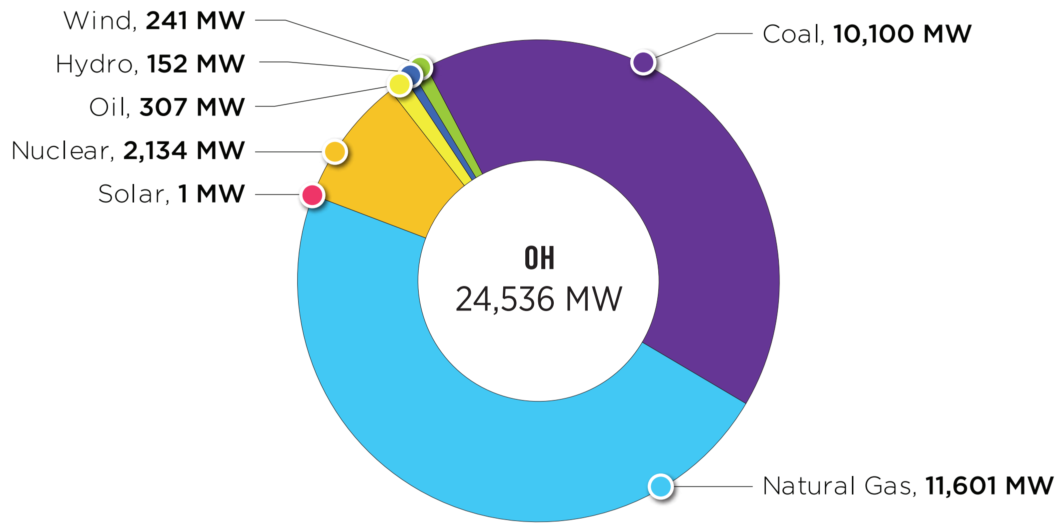
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.8.3 — Existing Generation

Existing generation in Ohio as of Dec. 31, 2020, is shown by fuel type in **Figure 6.42**.

Figure 6.42: Ohio – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



6.8.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Ohio, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in Ohio, as of Dec. 31, 2020, 239 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.34**, **Table 6.35**, **Figure 6.43**, **Figure 6.44** and **Figure 6.45**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.34: Ohio – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2020)

	Ohio Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	40	0.20%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	0	0.00%	559	0.53%
Natural Gas	7,413	36.33%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	6	0.03%	31	0.03%
Solar	11,232	55.04%	58,845	56.13%
Storage	1,417	6.95%	10,877	10.38%
Wind	300	1.47%	6,560	6.26%
Grand Total	20,407	100.00%	104,838	100.00%

Table 6.35: Ohio – Interconnection Requests by Fuel Type (Dec. 31, 2020)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	1	11.0	0	0.0	2	29.0	11	239.0	16	8,923.0	30	9,202.0
	Diesel	0	0.0	0	0.0	0	0.0	1	7.0	0	0.0	1	7.0
	Natural Gas	11	2,250.6	2	1,710.0	6	3,452.3	27	3,926.9	33	13,134.4	79	24,474.2
	Nuclear	0	0.0	0	0.0	0	0.0	1	16.0	0	0.0	1	16.0
	Oil	0	0.0	0	0.0	2	5.5	0	0.0	1	5.0	3	10.5
	Other	0	0.0	0	0.0	0	0.0	0	0.0	2	135.0	2	135.0
	Storage	22	1,417.4	0	0.0	0	0.0	6	0.0	24	756.2	52	2,173.7
Renewable	Biomass	0	0.0	0	0.0	0	0.0	1	0.0	3	185.0	4	185.0
	Hydro	0	0.0	0	0.0	0	0.0	1	112.0	8	76.2	9	188.2
	Methane	0	0.0	0	0.0	0	0.0	8	40.9	9	26.1	17	67.0
	Solar	167	10,640.1	2	209.0	13	382.5	1	1.0	119	3,655.6	302	14,888.1
	Wind	6	176.3	2	26.0	3	97.2	7	164.9	70	1,773.1	88	2,237.5
	Grand Total	207	14,495.5	6	1,945.0	26	3,966.5	64	4,507.6	285	28,669.6	588	53,584.2

Figure 6.43: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

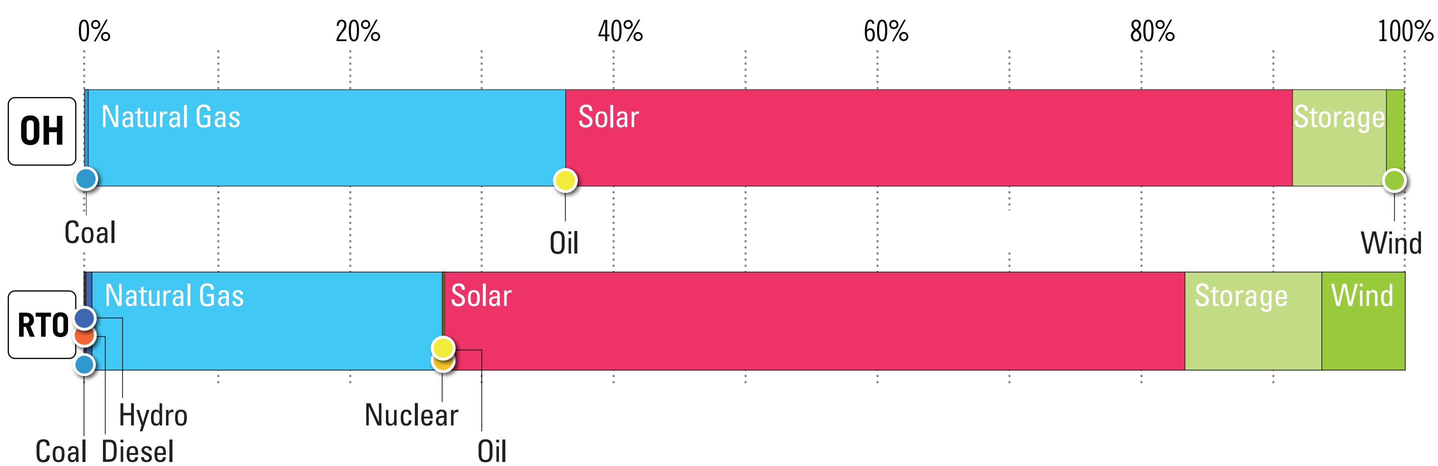


Figure 6.44: Ohio – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)

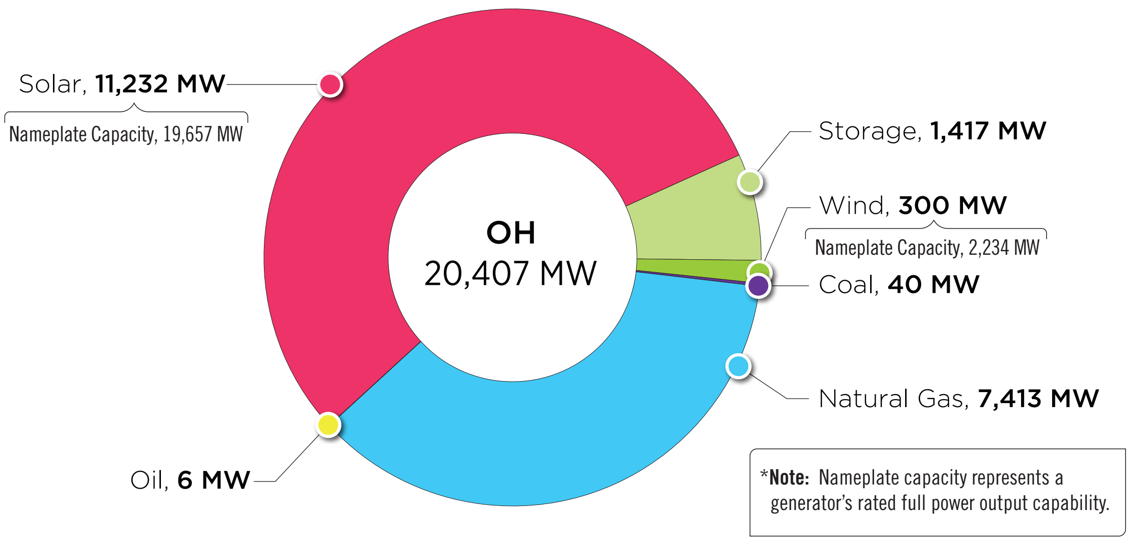
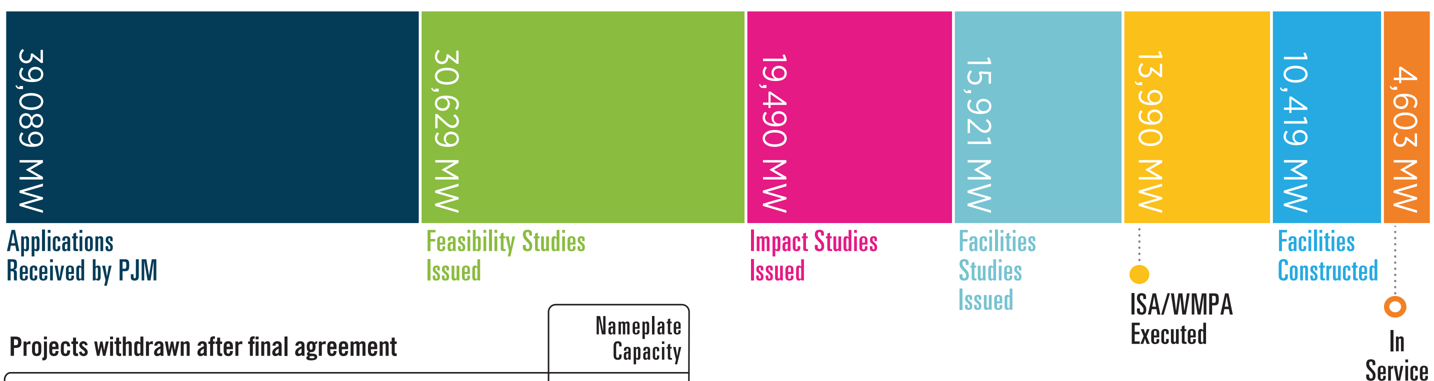


Figure 6.45: Ohio Progression History of Queue – Interconnection Requests (Dec. 31, 2020)



Projects withdrawn after final agreement

			Nameplate Capacity
22	Interconnection Service Agreements	3,557 MW	5,399 MW
12	Wholesale Market Participation Agreements	22 MW	82 MW

Percentage of planned capacity and projects that have reached commercial operation	12% Requested capacity megawatts	18% Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2020.

6.8.5 — Generation Deactivation

Known generating unit deactivation requests in Ohio between Jan. 1, 2020, and Dec. 31, 2020, are summarized in **Map 6.27** and **Table 6.36**.

Map 6.27: Ohio Generation Deactivations (Dec. 31, 2020)

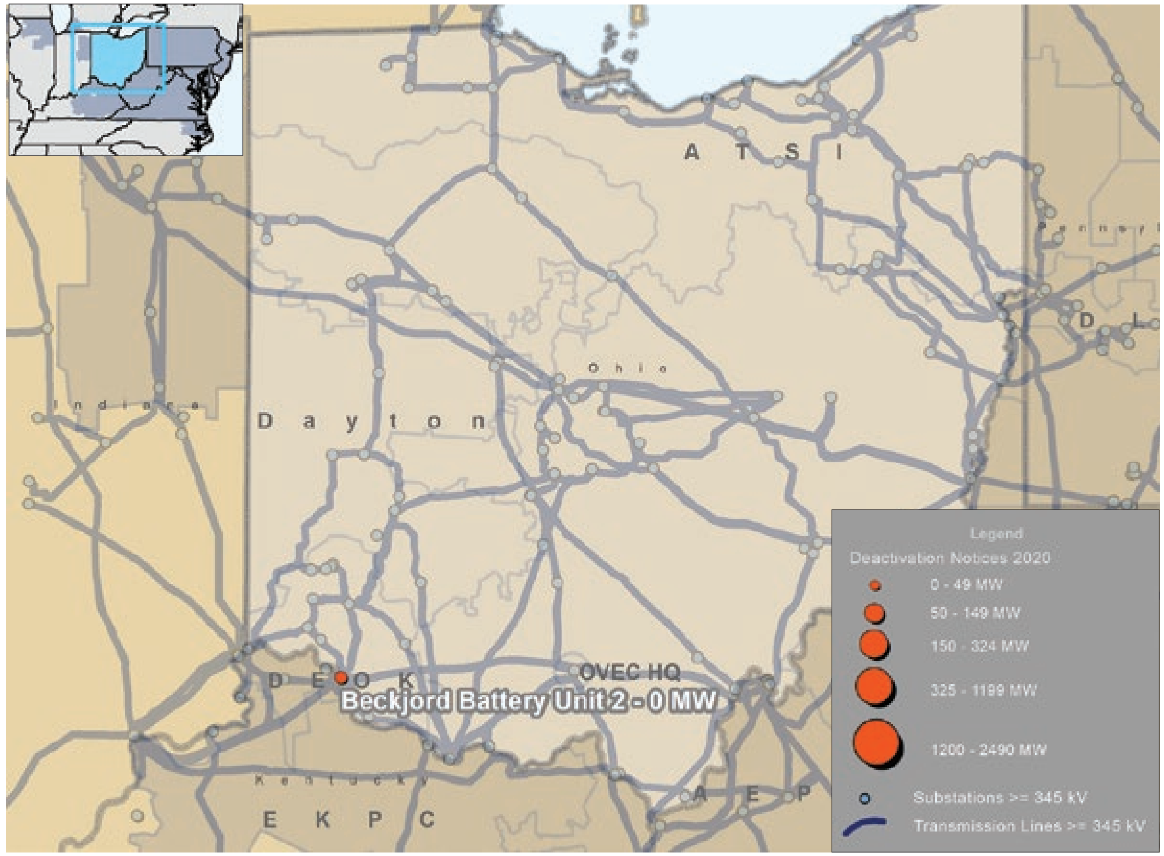


Table 6.36: Ohio Generation Deactivations (Dec. 31, 2020)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Beckjord Battery Unit 2	DEO&K	Storage	11/13/2020	2/3/2021	5	0.00

6.8.6 — Baseline Projects

2020 RTEP baseline projects greater than or equal to $10 million in Ohio are summarized in **Map 6.28** and **Table 6.37**.

Map 6.28: Ohio Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

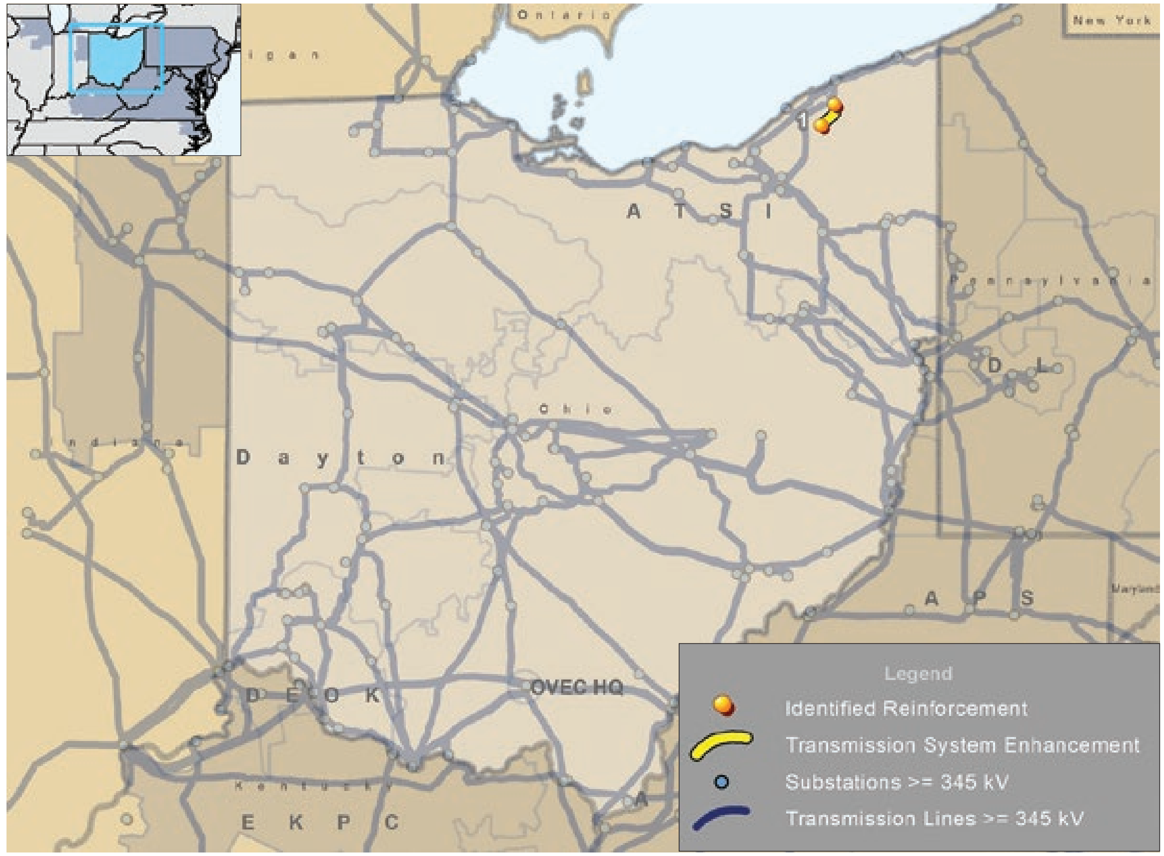


Table 6.37: Ohio Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3152	Reconductor the 8.4 mile section of the Leroy Center-Mayfield Q1 line between Leroy Center and Pawnee tap to achieve a rating of at least 160 MVA/192 MVA Summer Normal/Summer Emergency.	6/1/2024	$14.10	ATSI	11/14/2019

6.8.7 — Network Projects

No network projects greater than or equal to $10 million in Ohio were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the [Project Status](#) page of the PJM website.

6.8.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in Ohio are summarized in **Map 6.29** and **Table 6.38.**

Map 6.29: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

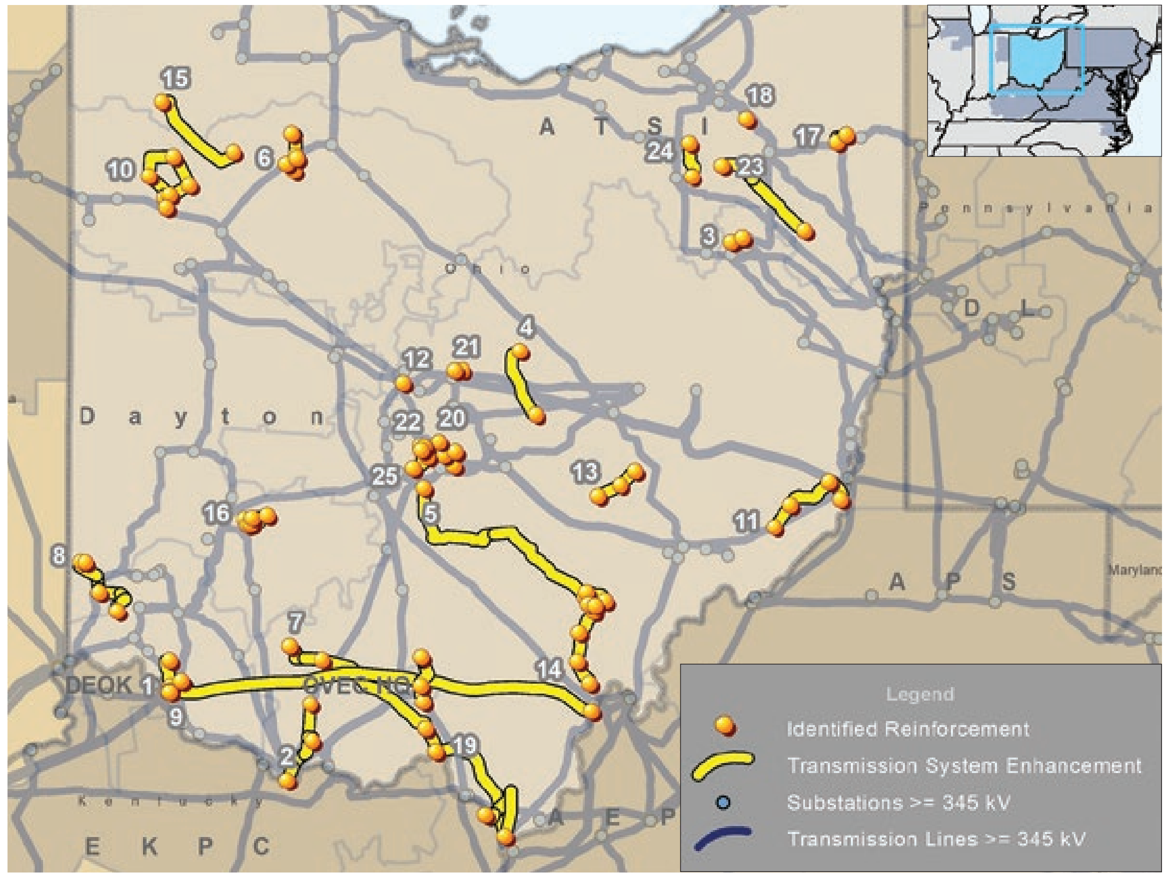


Table 6.38: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2181	At Clermont 138/69 kV: Retire the substation. Remove all equipment, foundations, underground cables, cableways, fencing and the control building. Connect the 138 kV feeder from Beckjord to the feeder from Summerside. Connect the 69 kV feeder from Blairville to the feeder from Amelia. At Beckjord 138/69 kV: Replace the 138 kV oil-filled circuit breaker that connects to the high side of the existing 138/69 kV transformer. Install a new 138 kV breaker connecting to a new 138/69 kV, 150 MVA transformer. Expand the substation and install four 69 kV circuit breakers to form a ring bus.	5/25/2023	$13.30	DEO&K	1/17/2020

Table 6.38: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2	S2184	Rebuild 22.0 miles of the existing 28.5-mile Stuart-Seaman 69 kV circuit with 795 ACSR. Retire approximately three miles of the line between West Union and structure 86. Thirty-two of the line's 170 structures were replaced since 2012 and will not be replaced as part of the rebuild.	12/1/2024	$65.00	AEP	2/21/2020
		Construct approximately 2.5 miles of new line from structure 86 on the Stuart-Seaman 69 kV line to Copeland station utilizing 795 ACSR.				
		Rebuild the 2-mile West Union-Copeland 69 kV line utilizing 795 ACSR. The line is part of the Stuart-Seaman 69 kV circuit and is currently radial fed from West Union switch.				
		Establish a 4-breaker 69 kV ring (3000A, 40kA) at the existing Copeland station to serve the Adams Rural Electric Cooperative, Inc. and AEP Ohio customers currently served from a hard tap at the end of the radial.				
		Retire existing West Union switch.				
		Install new 2000A 3-way phase-over-phase switch at Panhandle.				
		Replace the existing Poplar Flats switch with a new 2000A three-way phase-over-phase switch.				
		Remote end upgrade and equipment relocation work will be required at Seaman station to accommodate the new line at the station.				
3	S2185	Rebuild the 4-mile Sunnyside-Torrey 138 kV circuit. Supplement the existing right-of-way as needed to solve encroachments and other constraints.	8/1/2022	$12.70	AEP	2/21/2020
4	S2186	Rebuild the existing 138 kV line with 19.4 miles of new 1033 ACSR.	7/1/2023	$42.20	AEP	2/21/2020
5	S2198	Build new 0.3-mile double-circuit 138 kV extension from the Harrison-Lemaster 138 kV circuit to the new Lockbourne 138 kV station. Fiber will also be installed on the line.	9/23/2021	$13.80	AEP	2/21/2020
		Remove the existing 138 kV radial line from AEP Harrison to SCP Harrison station.				
		Build three short lines to interconnect to SCP's Lockbourne station to serve their three transformers.				
		Build a new 138 kV 5-breaker switch station (Lockbourne) with 3000A 40kA breakers and a capacitor bank (28.8 MVAR) to provide service to three SCP deliveries at the site.				
		Remove existing breaker 3E from the ring bus at Harrison.				

Table 6.38: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
6	S2199	Rebuild approximately 3 miles of New Liberty-North Baltimore 34 kV line. Rebuild 8 miles of North Findlay-North Baltimore No.1 34 kV line (advanced construction date due to imminent failure). Rebuild 0.15 miles of Whirlpool Extension. Build 1 mile of Oilers Switch Extension. Rebuild 2.9 miles of New Liberty-Findlay Center 34 kV line. At North Findlay station, replace 34.5 kV CBs F, G, H, J, K, L with 34.5 kV, 2000A 40 kA breakers. Replace 34.5 kV circuit switcher BB (40kA). Replace T1 and T2 with 90 MVA 138/69/34 kV transformers. At New Liberty station, remove existing T1 and T2. Replace with one 90 MVA ,138/69/34 kV transformer. Install high-side circuit switcher for new transformer. Expand station to build new 34.5 kV ring bus with (6) 2000A 40kA breakers. At Oilers switch station, build new ring bus in the clear with four 2000A 40 kA breakers to replace Morrical switch. At North Baltimore station, rebuild station with four 2000A 40 kA breakers. Install three-way 1200A switch called Touchstone to replace Liberty switch. Replace Cherry Street switch with a two-way 1200A switch. Replace West Melrose switch with 1200A switches. Replace Harvard Avenue switch with a three-way 1200A switch. Install three-way 1200A switch called Totten to eliminate the hard tap to the customer. Install two-way 1200A switch called Centrex to eliminate the hard tap to the customer. Replace Griffith switch with a two-way 1200A switch. Replace Whirlpool MOABs with 1200A capability.	8/1/2022	$85.90	AEP	2/21/2020
7	S2201	Rebuild 43.4 miles single-circuit line between Hillsboro-South Lucasville with 1033 ACSR. Rebuild 8.5 miles double circuit between Millbrook Park-South Lucasville with 1033 ACSR. Install a new three-way 2000A 138 kV, phase-over-phase switch at Sinking Springs.	9/30/2022	$126.80	AEP	2/21/2020
8	S2211	Locust ring bus: Install four 69 kV breakers in a ring bus configuration. Split the main feeder into two circuits. Terminate the two new main feeder circuits and the feeder to McGuffey each into their own position on the ring.	6/1/2023	$27.29	DEO&K	3/19/2020
		McGuffey automatic throw over: Install voltage sensing, control and associated equipment to implement an automatic throw-over (ATO) scheme in McGuffey Substation. Locust-Millville sectionalizing: Install switching facilities with energy management system (EMS) control and an ATO scheme in a new station at the Buckeye Rural Electric Cooperative (BERC) Stillwell-Beckett tap. Loop the main feeder though the new facilities. Install switching facilities with EMS control and transmission line sectionalizing (TLS) in or adjacent to BREC-Oxford Station. Loop the main feeder through the facilities.	12/31/2023			
		Millville ring bus: Install four 69 kV breakers in a ring bus configuration. Split the main feeder into two circuits. Extend the feeder that supplies BREC-Layhigh to Millville. Terminate the two new main feeder circuits, the feeder to BREC-Layhigh and the feeder to Hensley each into their own position on the ring.	6/1/2023			
		Millville-Fairfield sectionalizing: Install switching facilities with EMS control and TLS in or adjacent to BREC-Ross. Loop the main feeder though the new facilities. Install switching facilities with EMS control and TLS at or near the tap to BREC-Colerain. Loop the main feeder though the new facilities. Install ATO in River Circle Substation. Loop the main feeder through the facilities.	12/31/2023			

Table 6.38: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
9	S2213	Install a new transmission switching station (Arboles) to connect 138 kV lines to Don Marquis, Waverly, and Wakefield as well as four radial lines to serve the two new loads. The station will have 11 CBs (3000A 40 kA) in a breaker-and-a-half configuration. Department of Energy requires three feeds and has requested 138 kV service.	11/1/2021	$34.80	AEP	3/10/2020
		Reconfigure the existing Don Marquis extension in the six-wire configuration for 0.4 miles and rebuild 0.7 miles of the existing Marquis-Wakefield line as double circuit for two feeds from Waverly and Don Marquis.				
		Construct ~0.3 miles of new line to terminate the South Lucasville circuit into Arboles.				
		Construct two independent lines to serve the X-555 substation (DP No.1). The lines will be ~0.4 miles long each.				
		Construct two independent lines to serve the X-5001 substation (DP No.2). The lines will be ~0.8 miles long each.				
		At Don Marquis 345 kV, install three 345 kV, 4000A 63 kA circuit breakers to terminate the OVEC lines from Pierce and Kyger Creek. Install intertie metering. (AEP work)				
		At Kyger Creek station, remove X-530 No.1 exit and associated equipment. Update remote end relaying towards Don Marquis.			OVEC	
		At Pierce station, remove X-530 No.1 Exit and associated equipment. Update the remote end relaying towards Don Marquis.				
		Reconfigure 71.5 miles of the Pierce-Don Marquis line in the six-wire configuration. Construct 0.13 miles of line to tie into Don Marquis station.				
		Reconfigure 50.4 miles of the Kyger Creek-Don Marquis line in the six-wire configuration. Construct 0.5 miles of line to tie into Don Marquis station.				
		At Don Marquis 345 kV, install three 345 kV, 4000A 63 kA circuit breakers to terminate the OVEC lines from Pierce and Kyger Creek. Install intertie metering. (OVEC work)				
10	S2215	Rebuild 16 miles of 69 kV single-circuit line from North Continental Switch (existing switch to be retired) to Roselms Switch (located next to the existing Paulding Putnam Electric Cooperative Roselms station).	8/15/2022	$92.10	AEP	3/19/2020
		Build 9.4 miles of single-circuit 69 kV line from Roselms to near East Ottoville 69 kV Switch.				
		Rebuild 7.5 miles of double-circuit 69 kV line between East Ottoville Switch and Kalida Station (combining with the new Roselms to Kalida 69 kV circuit).				
		Rebuild 5.1 miles of single-circuit 69 kV line from East Ottoville to North Delphos.				
		At North Continental, remove normally open bypass switch.				
		At Fort Brown switch, install a three-way 69 kV, 1200 A phase-over-phase switch with sectionalizing capability.				
		At West Oakwood switch, install a three-way 69 kV, 1200 A phase-over-phase switch with sectionalizing capability.				
		At Roselms switch, install a new three-way 69 kV, 1200 A phase-over-phase switch with sectionalizing capability.				
		At Kalida station, move CB J from low side of Transformer 2 to terminate the new line from Roselms Switch. Move the circuit switcher XT2 from high side of transformer 2 to the high side of transformer 1. Remove existing T2 transformer.				
		Remote end work at North Delphos station.				
		At East Ottoville, install a three-way 69 kV, 1200 A phase-over-phase switch with sectionalizing capability.				
		At Ottoville station, install two three-way 69 kV, 1200 A, phase-over-phase switches with sectionalizing capability.				
		At Fort Jennings, replace hard tap with a three-way 69 kV, 1200 A phase-over-phase switch, with sectionalizing capability.				

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Table 6.38: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
11	S2216	At Lamping station, install a 138 kV breaker string with two breakers, a 90 MVA, 138-69 kV transformer, and one 69 kV breaker.	5/1/2023	$30.10	AEP	3/19/2020
		Construct a 10-mile 69 kV transmission line between Lamping and the Woodsfield area.				
		At the existing Woodsfield municipal electric station, install a three-way 69 kV switch with SCADA functionality (Cranes Nest Switch).				
		At the existing hard tap to Woodsfield municipal, install a three-way 69 kV switch with SCADA functionality (Standingstone Switch).				
		Remove the existing Cameron two-way switch and install a new three-way 69 kV switch with SCADA functionality.				
		At Switzer station, install two 138 kV line breakers (toward Herlan and Natrium).				
		At the 138 kV remote-end of Natrium, replace the line protection relays to coordinate with the upgrade at Switzer.				
		Modify the existing Switzer-Woodsfield 69 kV transmission line on each side of the switches due to the switch installation.				
12	S2217	At Hyatt station, replace two 345/138 kV, 300 MVA transformers 1A & 1B with 450 MVA units. Install three 345 kV, 5,000A / 63 kA circuit breakers to separate the transformer protection zones. Replace 138 kV breaker 105S with a 3,000A / 63 kA breaker. Install new 138 kV 3,000A breakers to terminate the second transformer.	11/27/2019	$25.00	AEP	3/19/2020
13	S2223	Rebuild ~12 miles of the Crooksville-Philo 138 kV circuit.	9/30/2022	$30.90	AEP	3/19/2020
		Replace Cannelville switch with a new phase-over-phase switch. Relocate the existing Cannesvsville-Guernsey-Muskingum Electric Cooperative 138 kV line to new Cannelville switch. The switch needs to be relocated to maintain service to the customer while the line is being rebuilt.				
14	S2224	Rebuild the existing ~8 mile Elliott-Lee 69 kV line to 138 kV and retire the existing 69 kV line.	10/1/2024	$55.50	AEP	3/19/2020
		Retire approximately 11.5 miles of the Philo-Rutland 138 kV line from Lee station north, including the de-energized portion of the line that runs through the Plains community.				
		Convert Lee to 138 kV service and install two line MOABs connected to the 138 kV line between Dexter and Elliot.				
		At Clark Street, replace 69 kV circuit breakers 61 & 64 (3000A 40 kA).				
		At Elliot, install a new 138/69 kV transformer (130 MVA) in addition to high- and low-side protection (3000A 40 kA) which will replace transformer No. 1 at Strouds Run that will be retired. Replace existing 138 kV circuit breaker 102 and 69 kV circuit breakers 61 and 66 (3000A 40 kA). Install 138 kV circuit breaker (3000A, 40 kA) on the new 138 kV line towards Dexter (via Lee) along with a 138 kV bus-tie breaker (3000 40 kA). Retire 69 kV circuit breaker 67"due to the conversion of Lee station to 138 kV.				
		Rebuild ~3.68 miles of single-circuit line from the Poston-Strouds Run line as double-circuit 138 kV transmission line to eliminate the hard tap on the line.				
		At Strouds Run, install a 138 kV line breaker (3000A 40 kA) towards Lemaster. Replace Transformer No. 2 high-side circuit switcher with a circuit breaker (3000A 40 kA). Replace the 69 kV circuit breaker 66 (3000A 40kA). Retire 138/69/13 kV, 33.6 MVA Transformer No.1, 69 kV circuit breaker 63 and circuit switcher No. 1.				
		At Lemaster station, install a 138 kV breaker (3000A 40kA) to accommodate the new circuit.				
		Remove Rosewood switch.				
15	S2246	Richland-East Leipsic 138 kV Line: Rebuild entire 15.8 mile of the ATSI-owned Richland-East Leipsic 138 kV line. Replace existing conductor (636 ACSR) with 795 ACSR. Install OPGW along the entire line. Upgrade Richland line terminal: Substation equipment for replacement includes: Breaker B13250, disconnect switches, line trap, CVT, tuner and COAX, substation conductor, relaying, and revenue metering.	12/31/2022	$16.90	ATSI	2/21/2020

Table 6.38: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
16	S2255	Construct a new 4-breaker ring bus substation called Jasper and build a new 1.5 mile transmission line extension from the existing 63611 switch to the new Jasper Substation for separate 69 kV feeds from Xenia Substation and Glady Run Substation.	12/31/2023	$10.20	DAY	4/20/2020
		Install two new 69 kV breakers at the South Charleston Substation.				
		Install a single 69 kV breaker and switch at the Cedarville Substation.				
17	S2264	Magellan 138 kV breaker-and-a-half: Construct a 138 kV 11-breaker breaker-and-a-half (future 12-breaker) substation. Loop the Highland-GM Lordstown 138 kV line by building approximately 0.5 miles of 138 kV line using 795 ACSR near structure 3069. Provide three 138 kV metering package. Install two capacitors totaling 86.4 MVAR @ 144.1 kV (multiple step). Build roughly 3.5 miles of 138 kV line from Highland to Magellan using 795 ACSR utilizing an open-arm position on the Highland-Lordstown No. 1 345 kV line.	8/31/2021	$31.80	ATSI	4/20/2020
18	S2265	Convert the Streetsboro 69 kV straight bus to a 5-circuit breaker ring bus. Build a double-circuit 69 kV line approximately 1.8 miles from Streetsboro Substation to eliminate the three-terminal line. Create Darrow-Streetsboro (~6.7 miles) and Ravenna-Streetsboro (~8.6 miles) 69 kV lines.	6/1/2020	$10.10	ATSI	1/17/2020
19	S2272	Rebuild the 35 miles of the South Point-Portsmouth double-circuit 138 kV line between Millbrook Park and South Point with 795 ACSR (257 MVA) or equivalent conductor.	12/15/2025	$148.70	AEP	5/22/2020
		Rebuild the 3.8 miles of the Bellefonte Extension line (138 kV) from the South Point-Portsmouth 138 kV line to Bellefonte with 795 ACSR (257 MVA) or equivalent conductor.				
		Perform remote-end work at South Point 138 kV station.				
20	S2282	Rebuild ~5.0 miles of 138 kV line between Astor-Shannon. The existing refugee switch will be retired.	11/1/2024	$60.80	AEP	6/19/2020
		Rebuild ~0.5 miles and construct ~4.6 miles of greenfield 138 kV line between Groves and Shannon to eliminate the three-terminal line.				
		Rebuild ~4.3 miles of 138 kV line between Bixby and Shannon.				
		Reconfigure lines at Shannon to accommodate the new 138 kV circuit from Groves. Install two new 138 kV 3000A 40 kA circuit breakers on circuits towards Brice and Bixby to prevent dissimilar zones of protection when bringing the third 138 kV circuit to the station.				
21	S2283	Build ~3.75 miles of single-circuit 138 kV transmission line from new Condit three-way MOAB switch (tapping the Centerburg-Trent 138 kV circuit) to Lott station (Consolidated Co-op).	6/1/2024	$10.64	AEP	6/19/2020
		Build Condit three-way MOAB 138 kV switch.				
22	S2284	Retire ~3.8 miles of underground oil-filled pipe type 138 kV circuit between Canal St.-Marion Rd.	5/1/2022	$45.00	AEP	6/19/2020
		Build ~3.1 miles of underground single-circuit 138 kV line between Marion Rd. and Mound St. using cross-linked polyethylene-insulated cable.				
		At Canal Street, install two new 138 kV CBs (3000A 63 kA) to electrically terminate the Buckeye Steel-Gay St. 138 kV circuit that runs through the station. Replace breaker 4 with new 138 kV CB (3000A 63 kA).				
		At Mound Street, install new 138 kV CB (3000A 63 kA) to accommodate new circuit from Marion Rd.				
		At Vine Street, install a 2 percent series line reactor towards Gay Street station to limit fault contribution increases from reconfigurations of lines in the area.				
		Perform remote-end relay work at Gay Street.				
		Perform remote-end relay work at Bixby station.				
		Perform relay upgrades and line termination structure replacement at Marion Road.				

Table 6.38: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
23	S2297	Convert East Akron 138 kV Substation into breaker-and-half configuration. Install a new control building. Reuse two breakers (B75 and 76). Upgrade three breakers (B43, B46 and B253) with 138 kV, 40 kA, SF6 circuit breaker. Install seven additional 138 kV, 40 kA, SF6 circuit breakers. Replace and install switches, surge arrestors, capacitive voltage transformers, station service voltage transformers. Upgrade wave trap on Knox exit. Replace line tuner and coax.	12/30/2023	$13.80	ATSI	5/22/2020
24	S2298	Convert Barberton 138 kV Substation into double bus, double breaker configuration. Install a new control building. Reuse two breakers (B75 & 76). Upgrade five breakers (B124, B45, B74, B37 & B357) with 138 kV, 40 kA, SF6 circuit breakers. Install nine additional 138 kV, 40 kA, SF6 circuit breakers. Replace and install switches, surge arrestors, CVTs, SSVTs. Upgrade less than 0.1 mile section of the Barberton-West Akron 138 kV line from 605 ACSR conductor to 795 ACSS conductor.	12/1/2024	$14.70	ATSI	5/22/2020
25	S2342	Marion-Parsons 40 kV: Retire ~5.2 miles of double-circuit 40 kV line between Marion and Parsons. Parsons 138 kV Extension: Extend the Canal Street-White Road 138 kV circuit to Parsons with ~2.0 miles of double- circuit 138 kV line (Greenfield) using 795 ACSR, 26/7 Drake conductor. Extend fiber cable and install redundant fiber cable for relaying and communication to Parsons station. Parsons 138 kV substation: Replace existing 40 kV yard with 138 kV ring bus. Perform remote end work at Canal Street and White Road stations. Marion 138 kV substation: Retire existing circuit breaker 21.	8/1/2022	$27.89	AEP	10/16/2020

6.8.9 — Merchant Transmission Project Requests

As of Dec. 31, 2020, PJM's queue contained one merchant transmission project request which includes a terminal in Ohio as shown in **Map 6.30** and **Table 6.39.**

Map 6.30: Ohio Merchant Transmission Project Requests (Dec. 31, 2020)

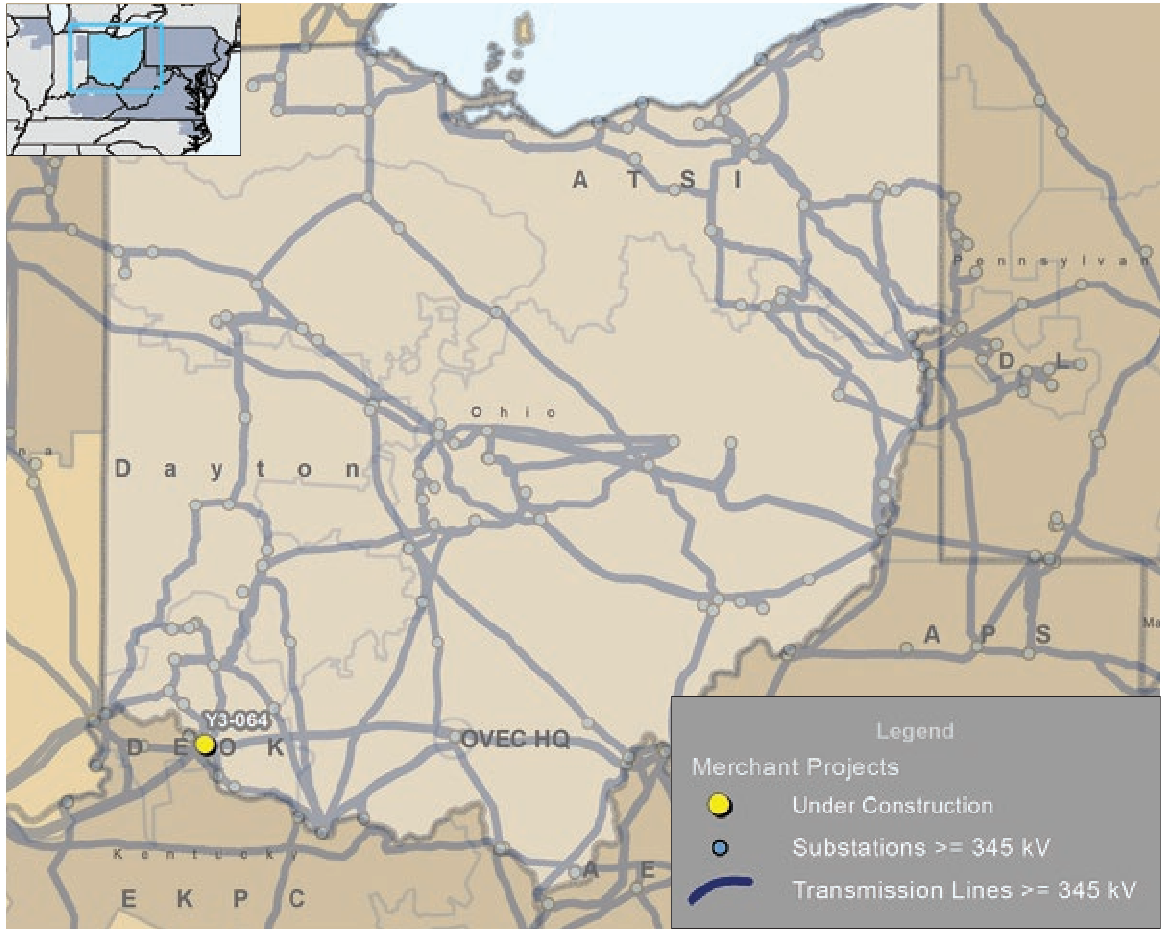


Table 6.39: Ohio Merchant Transmission Project Requests (Dec. 31, 2020)

Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
Y3-064	Pierce-Beckjord 138 kV	DEO&K	Under Construction	12/20/2020	160.0

6.9: Pennsylvania RTEP Summary

6.9.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Pennsylvania, including facilities owned and operated by Allegheny Power (AP), Duquesne Light Co. (DLCO), Met-Ed, Pennsylvania Electric Co. (PENELEC), PECO Energy Co. (PECO), PPL Electric Utilities (PPL), UGI Utilities (UGI), Rock Springs and American Transmission Systems, Inc. (ATSI) as shown on **Map 6.31**. Pennsylvania's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Renewable Portfolio Standards

From an energy policy perspective, Pennsylvania has a renewable portfolio standard (RPS) to advance renewable generation. Many states have instituted goals with respect to the percentage of generation expected to be fueled by renewable fuels in coming years.

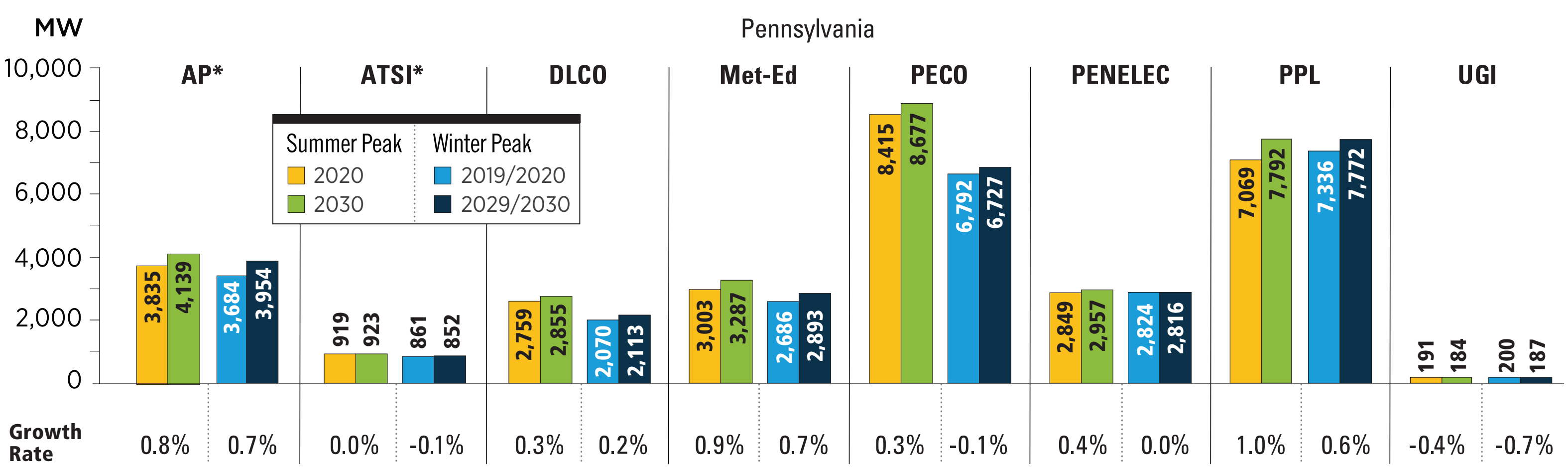
Pennsylvania has a mandatory alternative energy portfolio standard (AEPS) target of 8 percent Tier 1 resources and 10 percent Tier 2 resources by 2021. The AEPS includes a solar carve-out of 0.5 percent by 2021, and solar resources applying toward the AEPS must be located within the state of Pennsylvania.

Map 6.31: PJM Service Area in Pennsylvania

6.9.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.46** summarizes the expected loads within the state of Pennsylvania and across all of PJM.

Figure 6.46: Pennsylvania – 2020 Load Forecast Report



*Serves load outside PA

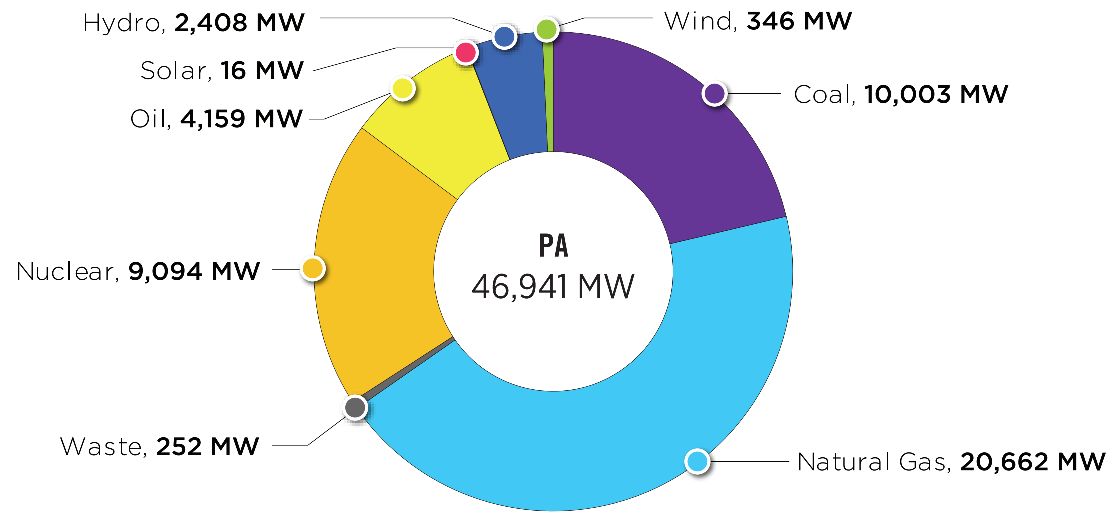
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.9.3 — Existing Generation

Existing generation in Pennsylvania as of Dec. 31, 2020, is shown by fuel type in **Figure 6.47**.

Figure 6.47: Pennsylvania – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



6.9.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Pennsylvania, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in Pennsylvania, as of Dec. 31, 2020, 478 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.40**, **Table 6.41**, **Figure 6.48**, **Figure 6.49** and **Figure 6.50**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.40: Pennsylvania – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2020)

	Pennsylvania Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	4	0.03%	4	0.00%
Hydro	507	3.94%	559	0.53%
Natural Gas	4,113	31.99%	27,804	26.52%
Nuclear	44	0.34%	81	0.08%
Oil	8	0.06%	31	0.03%
Solar	7,024	54.63%	58,845	56.13%
Storage	988	7.69%	10,877	10.38%
Wind	170	1.32%	6,560	6.26%
Grand Total	**12,857**	**100.00%**	**104,838**	**100.00%**

Table 6.41: Pennsylvania – Interconnection Requests by Fuel Type (Dec. 31, 2020)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	17	229.0	28	14,354.6	45	14,583.6
	Diesel	0	0.0	0	0.0	1	4.1	3	33.3	12	51.5	16	88.9
	Natural Gas	13	952.6	1	950.0	27	2,210.1	98	20,477.1	245	89,688.0	384	114,277.8
	Nuclear	2	0.0	0	0.0	1	44.0	14	2,565.0	12	1,731.0	29	4,340.0
	Oil	0	0.0	0	0.0	6	7.5	3	9.4	9	1,307.0	18	1,323.9
	Other	0	0.0	0	0.0	0	0.0	2	306.5	6	344.0	8	650.5
	Storage	38	976.5	2	11.8	1	0.0	5	0.0	39	722.8	85	1,711.1
Renewable	Biomass	0	0.0	0	0.0	0	0.0	2	15.4	4	36.5	6	51.9
	Hydro	6	506.5	0	0.0	0	0.0	12	480.8	17	443.9	35	1,431.1
	Methane	0	0.0	0	0.0	0	0.0	24	130.7	37	201.3	61	332.0
	Solar	312	6,704.5	9	129.4	49	190.2	10	37.4	181	2,961.7	561	10,023.2
	Wind	5	101.7	2	21.4	3	47.0	39	259.6	137	1,749.0	186	2,178.7
	Wood	0	0.0	0	0.0	0	0.0	0	0.0	1	16.0	1	16.0
	Grand Total	**376**	**9,241.7**	**14**	**1,112.7**	**88**	**2,502.9**	**229**	**24,544.2**	**728**	**113,607.2**	**1,435**	**151,008.7**

Figure 6.48: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

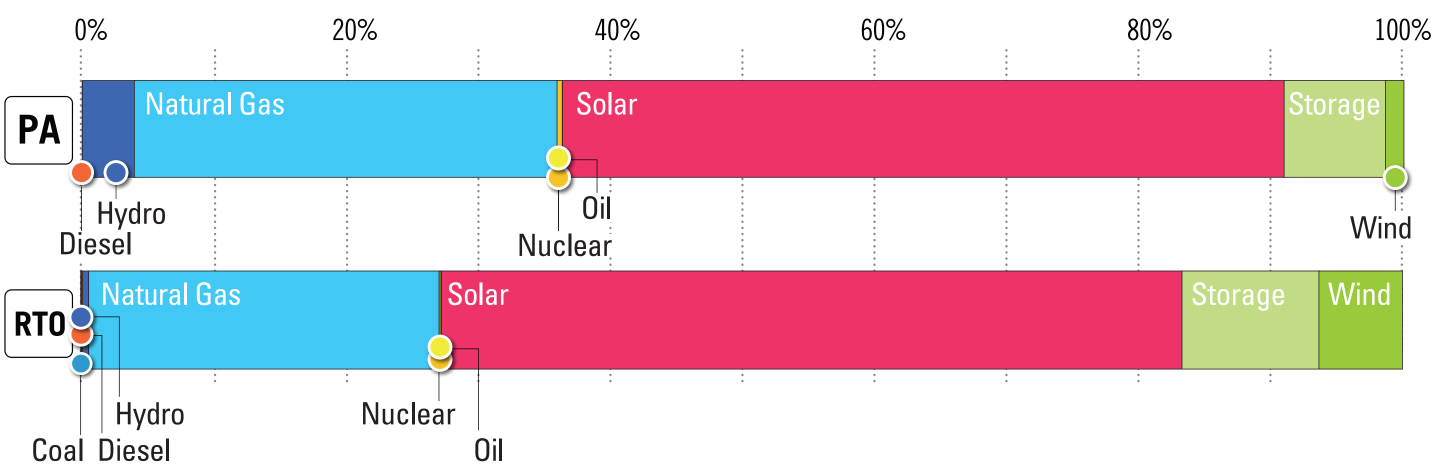


Figure 6.49: Pennsylvania – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)

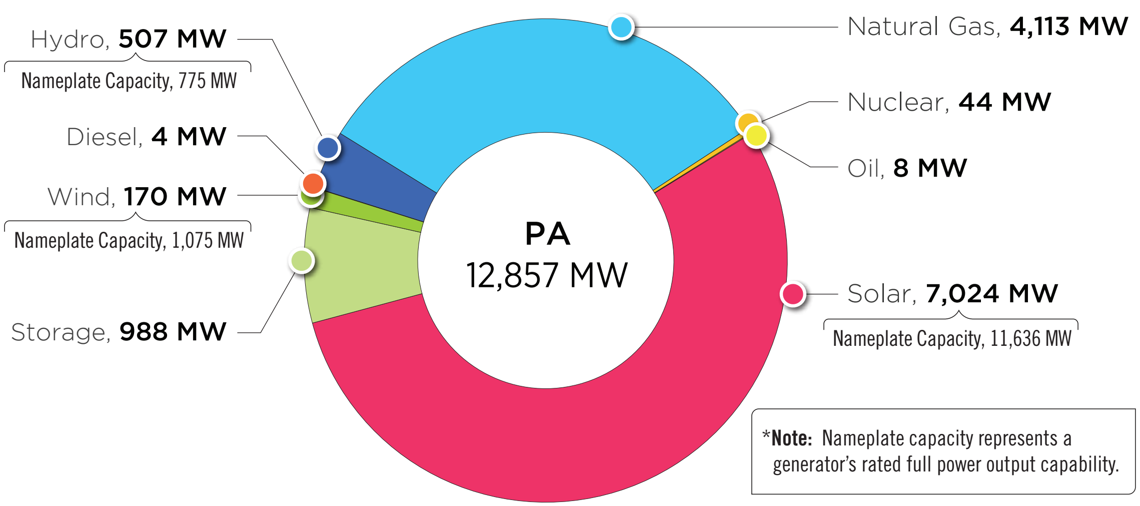
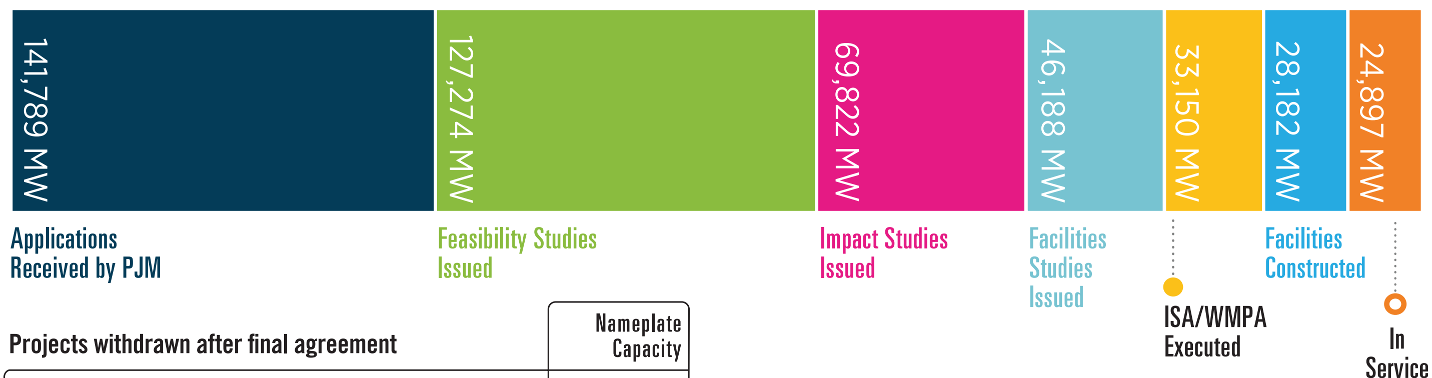


Figure 6.50: Pennsylvania Progression History of Queue – Interconnection Requests (Dec. 31, 2020)



Projects withdrawn after final agreement

			Nameplate Capacity
56	Interconnection Service Agreements	6,049 MW	7,836 MW
49	Wholesale Market Participation Agreements	308 MW	423 MW

Percentage of planned capacity and projects that have reached commercial operation	18% Requested capacity megawatts	24 % Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2020.

6.9.5 — Generation Deactivations

Known generating unit deactivation requests in Pennsylvania between Jan. 1, 2020, and Dec. 31, 2020, are summarized in **Map 6.32** and **Table 6.42**.

Map 6.32: Pennsylvania Generation Deactivations (Dec. 31, 2020)

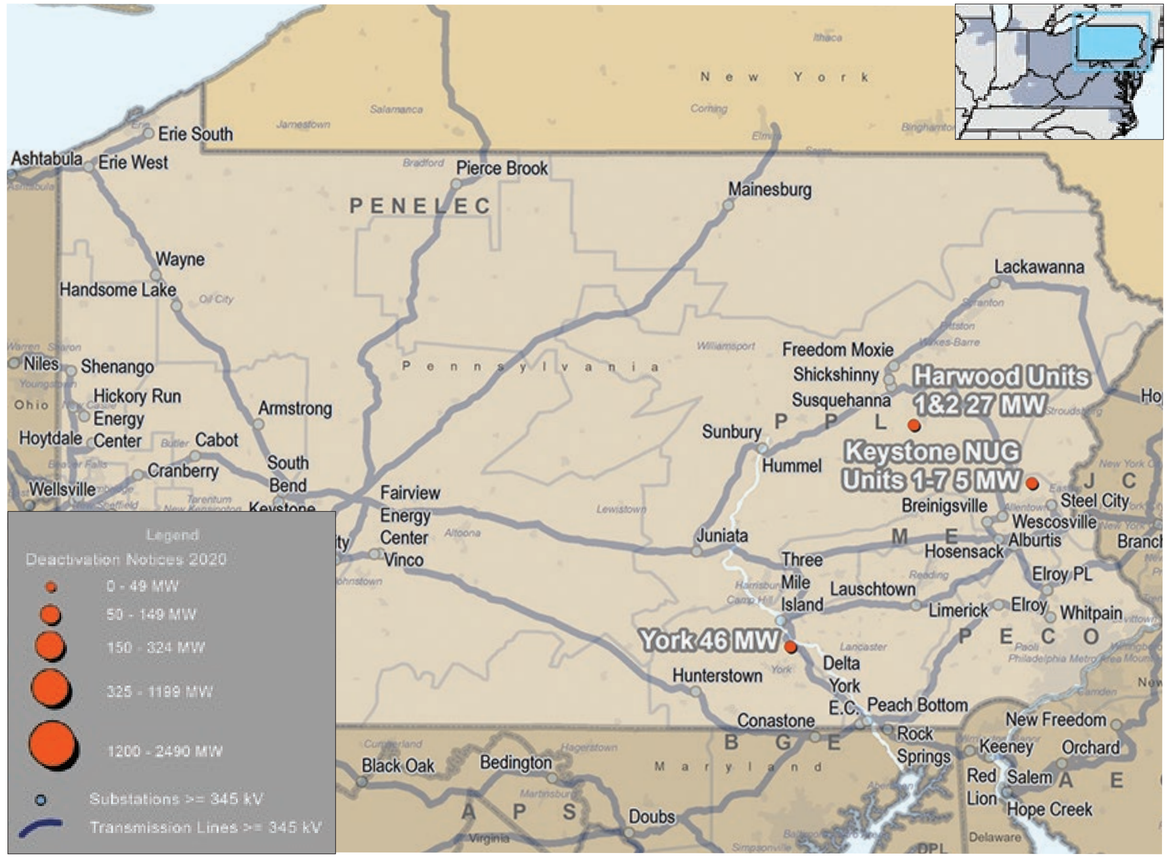


Table 6.42: Pennsylvania Generation Deactivations (Dec. 31, 2020)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Keystone NUG Recovery (Units 1–7)	PPL	Methane	2/28/2020	6/1/2020	25	4.90
Harwood Unit 1		Oil	10/29/2020	5/31/2021	53	13.60
Harwood Unit 2			10/29/2020	5/31/2021	53	13.60
York Generation Facility	METED	Natural Gas	10/29/2020	5/31/2022	31	46.20

6.9.6 — Baseline Projects

2020 RTEP baseline projects greater than or equal to $10 million in Pennsylvania are summarized in **Map 6.33** and **Table 6.43**.

6.9.7 — Network Projects

No network projects greater than or equal to $10 million in Pennsylvania were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.33: Pennsylvania Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

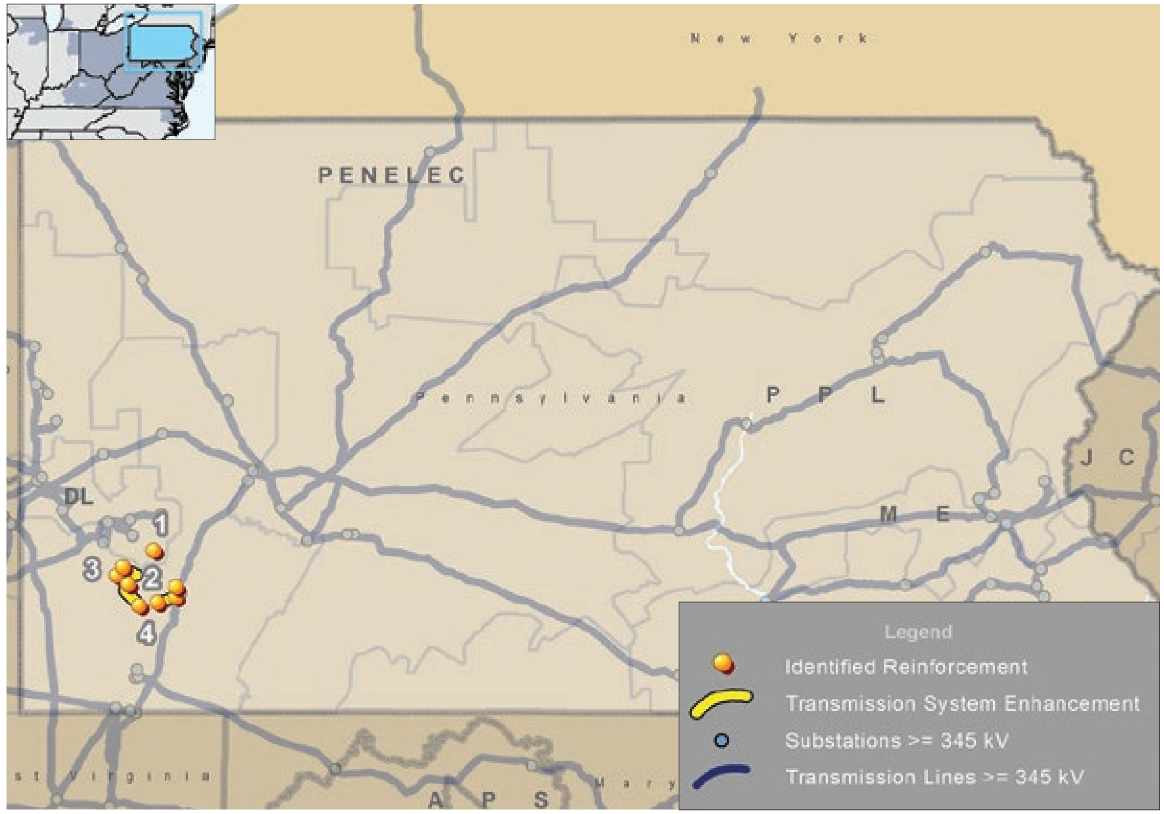


Table 6.43: Pennsylvania Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3011	Upgrade 138 kV breaker Z-78 Logans at Dravosburg.	6/1/2021	$29.42	DLCO	1/17/2020
2	B3015	Upgrade terminal equipment at Mitchell for Mitchell-Elrama 138 kV line.		$39.25	AP	9/12/2019
3	B3064	Upgrade line relaying at Piney Fork and Bethel Park for Piney Fork-Elrama 138 kV line and Bethel Park-Elrama 138 kV line.		$13.05		
4	B3214	Reconductor the Yukon-Smithton-Shepler Hill Jct 138 kV line. Upgrade terminal equipment at Yukon and replace line relaying at Mitchell and Charleroi.	6/1/2023	$21.40		5/12/2020

6.9.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in Pennsylvania are summarized in **Map 6.34** and **Table 6.44**.

Map 6.34: Pennsylvania Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

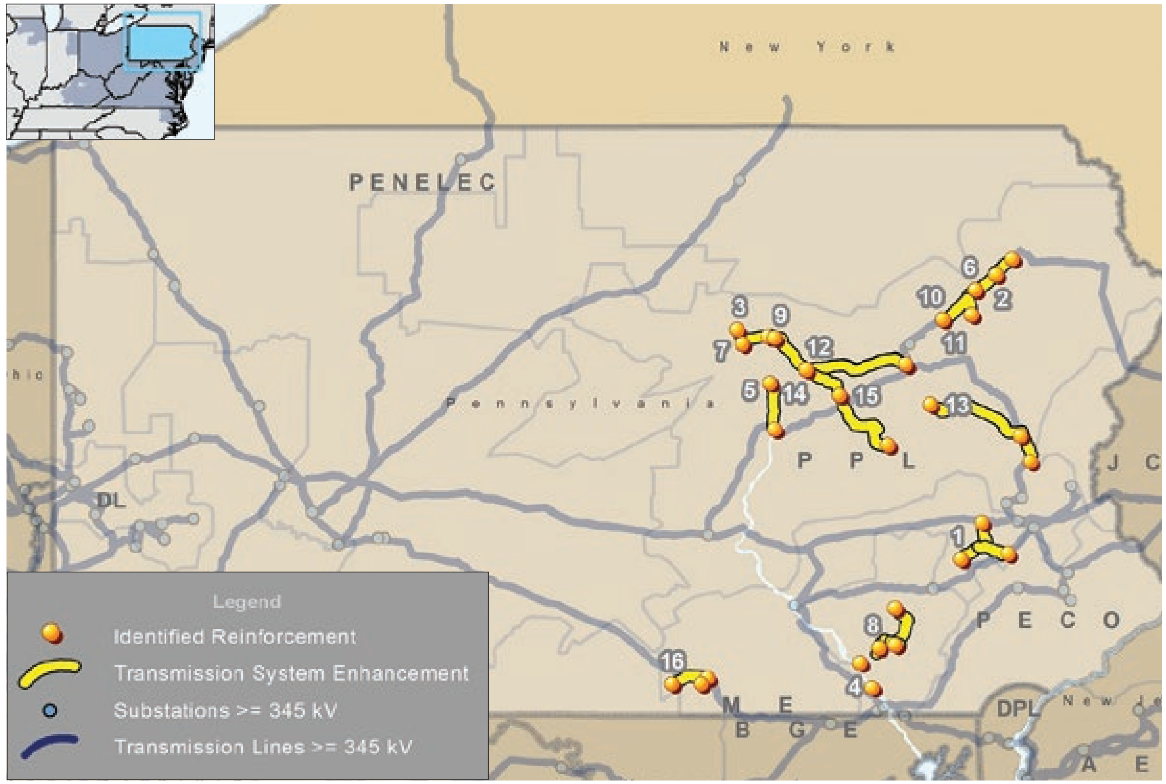


Table 6.44: Pennsylvania Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	s2310	Rebuild and reconductor Carsonia-Lyons-North Boyertown 69 kV line.	12/31/2025	$26.40	METED	7/16/2020
		Replace disconnect switches, substation conductor and line relaying at Carsonia 69 kV substation.				
		Replace disconnect switches and substation conductor at Friedensburg 69 kV substation.				
		Replace circuit breaker and disconnect switches at North Boyertown 69 kV substation.				

Table 6.44: Pennsylvania Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2	S2363	Rebuild the 5 mile Corten tower section of the Summit-Lackawanna 1 & 2 230 kV circuits with steel monopoles and new conductor.	12/31/2023	$14.30	PPL	10/6/2020
3	S2364	Rebuild the 4.1 mile Corten tower section of the Elimsport-Lycoming 2 & 3 230 kV circuits with steel monopoles and new conductor.		$10.40		
4	S2365	Rebuild the 5.2 mile Corten tower section of the Manor-Millwood 230 kV & Face Rock-Millwood 1 69 kV circuits with steel monopoles and new conductor.	12/31/2024	$13.20		
5	S2366	Rebuild the entire 10.5 miles of the Sunbury-Milton 230 kV and Sunbury-Milton 69 kV line with steel monopoles and new conductor.	12/31/2023	$26.10		
6	S2367	Rebuild the 7.7 mile Corten tower section of the Stanton-Summit 3 & 4 230 kV circuits with steel monopoles and new conductor.	12/31/2025	$21.10		
7	S2368	Rebuild the 8.0 miles of Corten tower sections of the Saegers-Elimsport and Clinton-Elimsport/Clinton-Saegers 230 kV lines. with steel monopoles and new conductor.	12/31/2026	$23.10		
8	S2369	Rebuild the 20.4 mile Corten tower section of the South Akron-Millwood 230 kV and Millwood-Strasburg tie 69 kV lines with steel monopoles and new conductor.	12/31/2025	$53.30		
9	S2370	Rebuild the 6.2 mile Corten tower section of the Montour-Saegers 1 & 2 230 kV lines with steel monopoles and new conductor.	12/31/2027	$17.50		
10	S2371	Rebuild the 8.5 mile Corten tower section of the Jenkins-Stanton and Mountain-Stanton 230 kV lines with steel monopoles and new conductor.	12/31/2028	$22.80		
11	S2372	Rebuild the 9.8 mile Corten tower section of the Mountain-Stanton and Mountain-Jenkins 230 kV lines with steel monopoles and new conductor.	12/31/2029	$27.00		
12	S2373	Rebuild the 21.9 miles of Corten tower sections of the Montour-Susquehanna and Montour-Susquehanna T10 230 kV lines with steel monopoles and new conductor.		$69.60		
13	S2374	Rebuild the 38.0 miles of Corten tower sections of the Siegfried-Harwood and Harwood-East Palmerton/Siegfried-East Palmerton 230 kV lines with steel monopoles and new conductor.	12/31/2026	$136.80		
14	S2375	Rebuild the 9.25 mile Corten tower section of the Montour-Columbia 230 kV line with steel monopoles and new conductor.	12/31/2028	$28.20		
15	S2376	Rebuild the 25.9 mile Corten tower section of the Frackville-Columbia 230 kV line with steel monopoles and new conductor.	12/31/2030	$91.90		
16	S2381	Loop the Hunterstown-Lincoln 115 kV line, approximately 9 miles, into Orrtanna substation by constructing a double-circuit 115 kV line adjacent to the existing radial 963 line. Remove the existing radial 963 line from Orrtanna tap to Orrtanna (~9 miles).	12/31/2021	$38.50	METED	10/15/2020

6.9.9 — Merchant Transmission Project Requests

As of Dec. 31, 2020, PJM's queue contained two merchant transmission project requests which include a terminal in Pennsylvania, as shown in **Map 6.35** and **Table 6.45**.

Map 6.35: Pennsylvania Merchant Transmission Project Requests (Dec. 31, 2020)

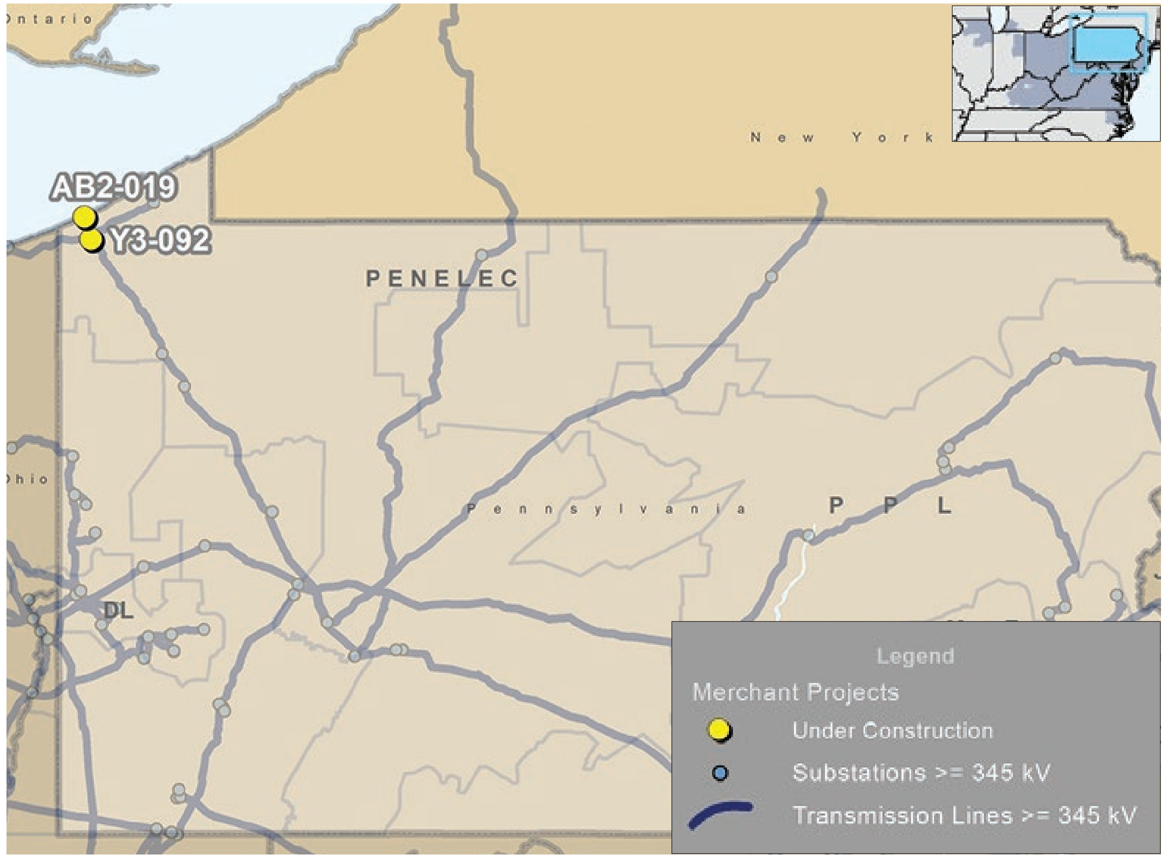


Table 6.45: Pennsylvania Merchant Transmission Project Requests (Dec. 31, 2020)

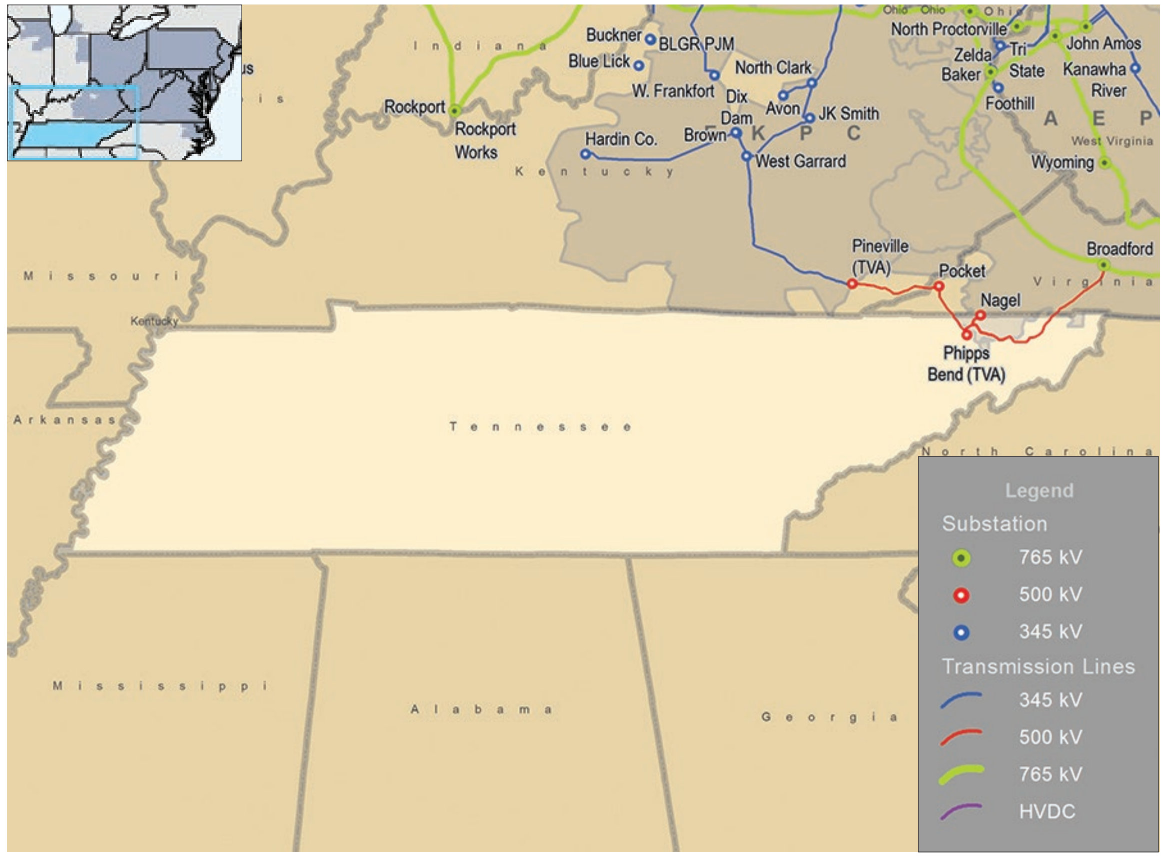
Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
Y3-092	Erie West 345 kV	PENELEC	Under Construction	3/31/2024	1,000.0
AB2-019	Erie West 345 kV	PENELEC	Under Construction	3/31/2024	28.0

6.10: Tennessee RTEP Summary

6.10.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Tennessee, including facilities owned and operated by American Electric Power (AEP) as shown on **Map 6.36**. Tennessee's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Map 6.36: PJM Service Area in Tennessee



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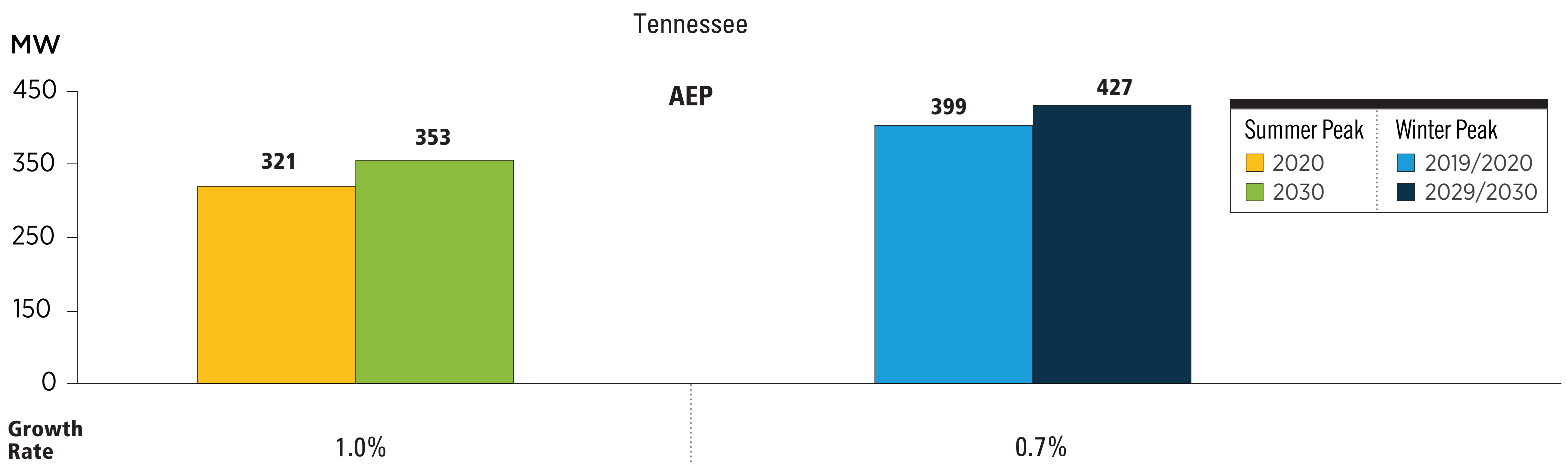
6.10.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.51** summarizes the expected loads within the state of Tennessee and across all of PJM.

Figure 6.51: Tennessee – 2020 Load Forecast Report



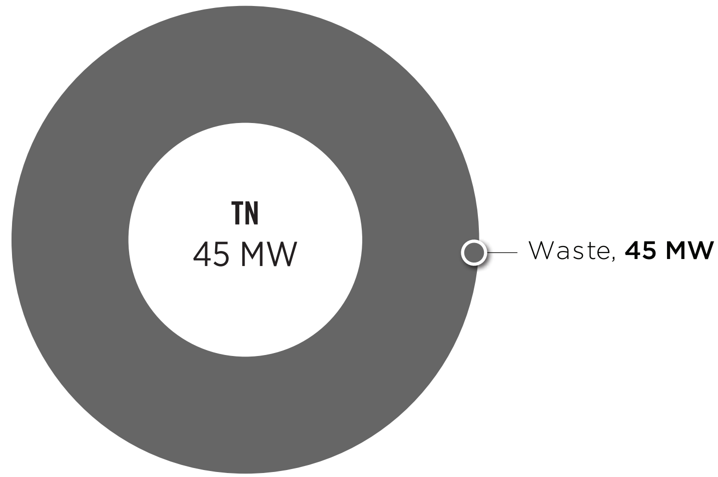
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.10.3 — Existing Generation

Existing generation in Tennessee as of Dec. 31, 2020, is shown by fuel type in **Figure 6.52**.

Figure 6.52: Tennessee – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



6.10.4 — Interconnection Requests

PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria.

Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in Tennessee, as of Dec. 31, 2020, there were no queued projects actively under study, or under construction as shown in the summaries presented in **Table 6.46** and **Figure 6.53.** These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

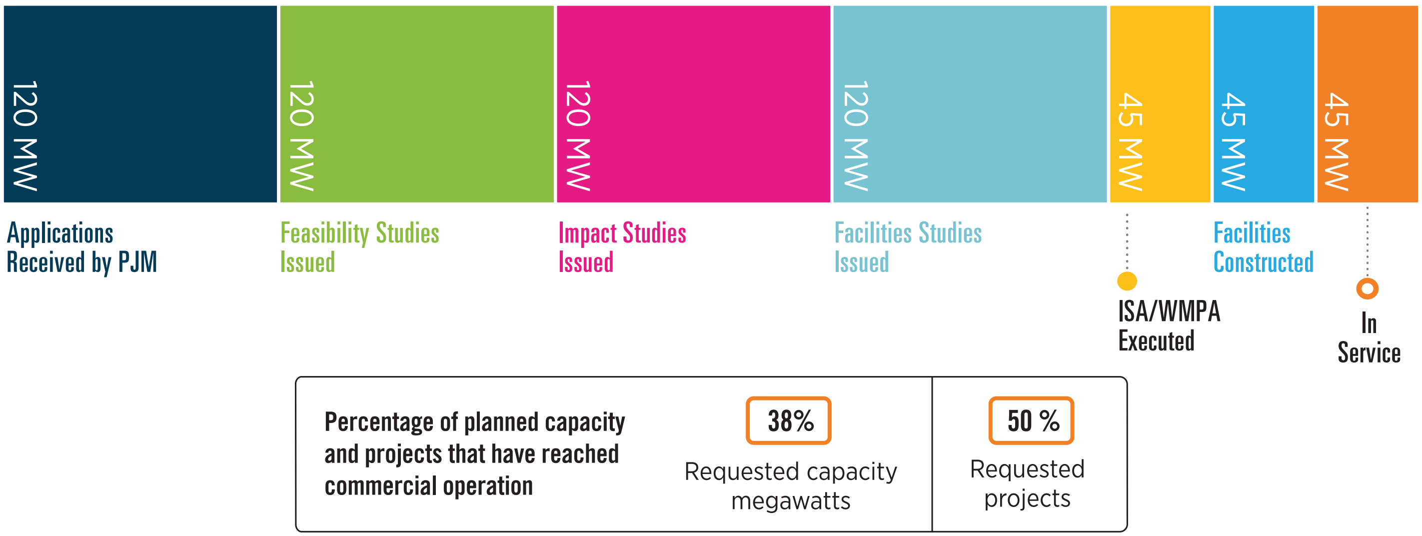
6.10.5 — Generation Deactivation

There were no known generating unit deactivation requests in Tennessee between Jan. 1, 2020, and Dec. 31, 2020, as part of the 2020 RTEP.

Table 6.46: Tennessee – Interconnection Requests by Fuel Type (Dec. 31 2020)

		Complete					
		In Service		Withdrawn		Grand Total	
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0	1	75	1	75
Renewable	Biomass	1	45	0	0	1	45
	Grand Total	1	45	1	75	2	120

Figure 6.53: Tennessee Progression History of Queue – Interconnection Requests (Dec. 31, 2020)



This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2020.

6.10.6 — Baseline Projects

No baseline projects greater than or equal to $10 million in Tennessee were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.10.7 — Network Projects

No network projects greater than or equal to $10 million in Tennessee were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.10.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in Tennessee are summarized in **Map 6.37** and **Table 6.47**.

6.10.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in Tennessee were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.37: Tennessee Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

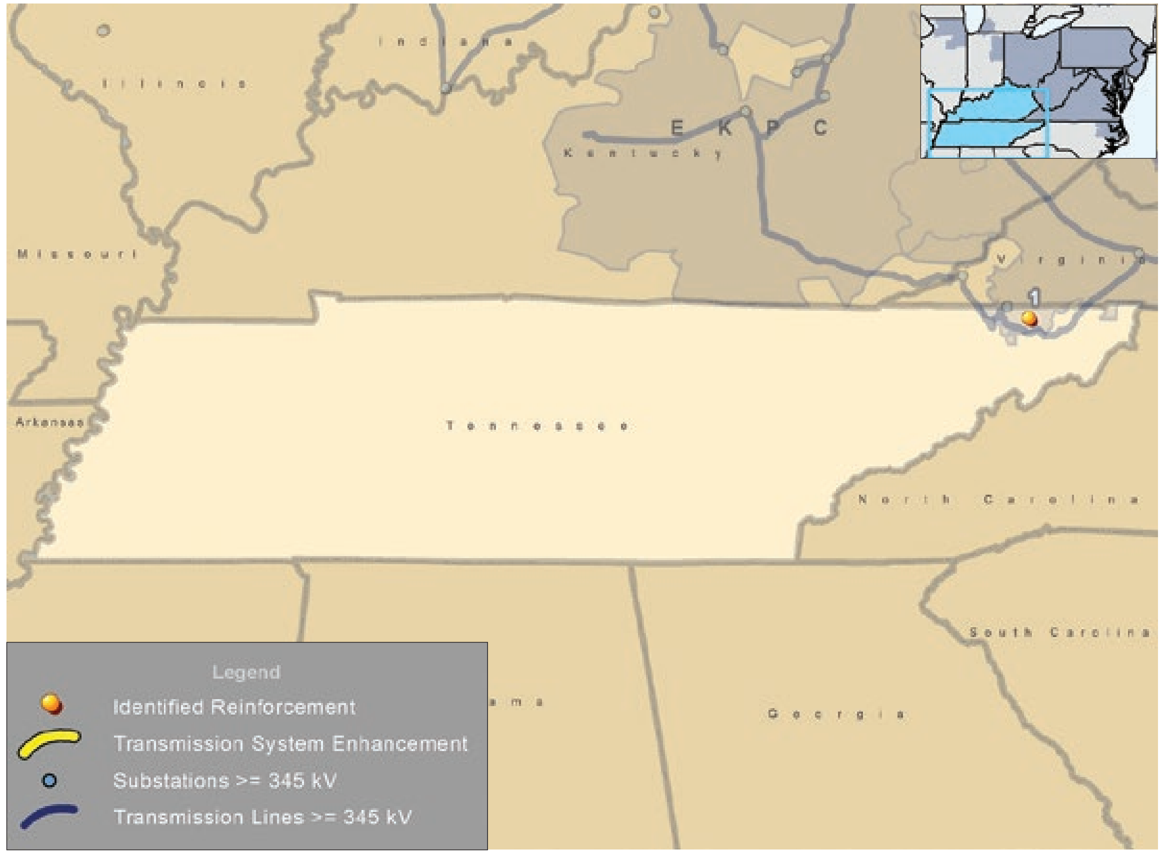


Table 6.47: Tennessee Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2249	Holston substation: Replace existing 138/34.5 kV, 45 MVA transformer No. 1 with a new 138/69/34.5 kV, 90 MVA transformer. Replace existing high-side MOAB switches on transformer No. 1 with new 138 kV, 3000 A 40 KA circuit breaker. Replace existing ground transformers No. 8 and No. 9 with new ground banks. Reconfigure the existing 34.5 kV into a ring bus configuration with five new 34.5 kV breakers.	12/1/2023	$11.50	AEP	4/20/2020

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

6.11: Virginia RTEP Summary

6.11.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Virginia, including facilities owned and operated by Allegheny Power (AP), American Electric Power (AEP), Delmarva Power & Light Co. (DP&L) and Dominion as shown on **Map 6.38**. Virginia's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Renewable Portfolio Standards

From an energy policy perspective, Virginia has a renewable portfolio standard (RPS) to advance renewable generation. Many states have instituted goals with respect to the percentage of generation expected to be fueled by renewable fuels in coming years.

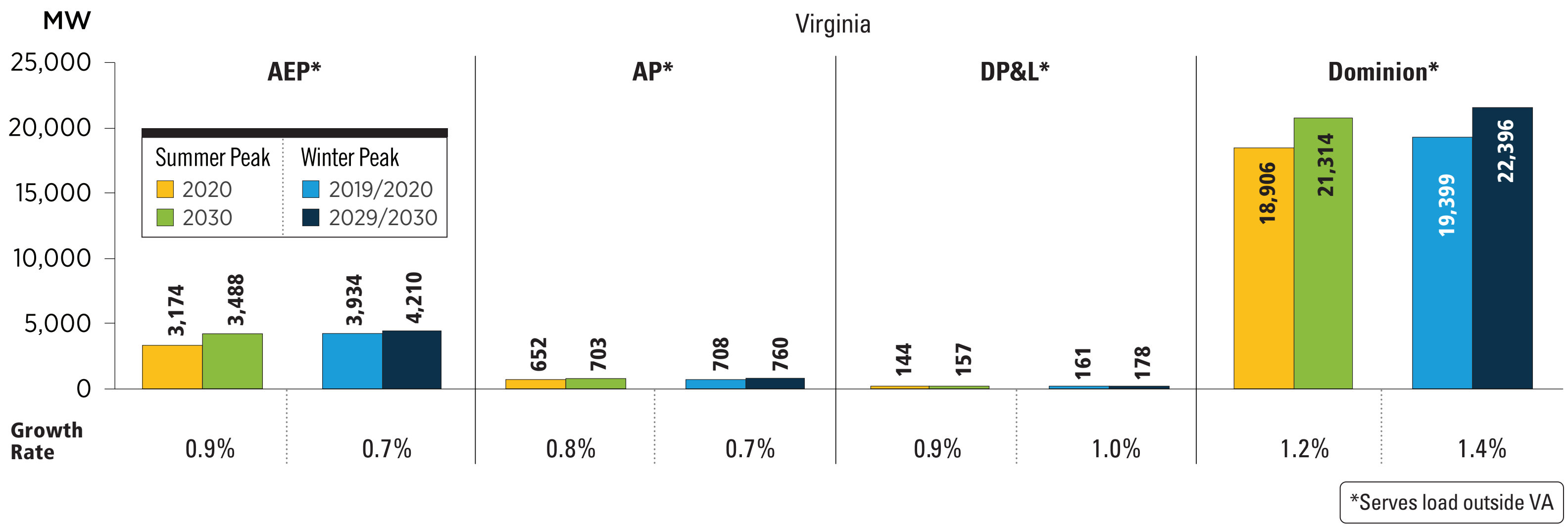
Virginia has a mandatory RPS target of 100 percent by 2045 or 2050, depending on the utility service territory. The state's RPS was a voluntary goal until legislation was passed in 2020. The RPS target is one of two in the PJM region set at 100 percent, with the other being the District of Columbia's.

Map 6.38: PJM Service Area in Virginia

6.11.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.54** summarizes the expected loads within the state of Virginia and across all of PJM.

Figure 6.54: Virginia – 2020 Load Forecast Report



PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

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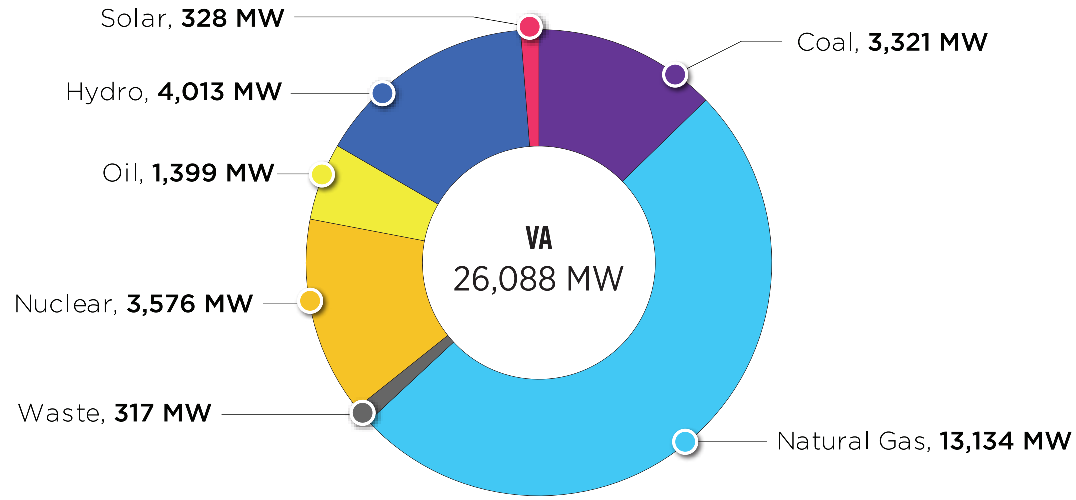
6.11.3 — Existing Generation

Existing generation in Virginia as of Dec. 31, 2020, is shown by fuel type in **Figure 6.55**.

Figure 6.55: Virginia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



6.11.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Virginia, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in Virginia, as of Dec. 31, 2020, 438 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.48**, **Table 6.49**, **Figure 6.56**, **Figure 6.57** and **Figure 6.58**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.48: Virginia – Capacity by Fuel Type – Interconnection Requests (Dec. 31. 2020)

	Virginia Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	0	0.00%	559	0.53%
Natural Gas	4,300	17.78%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	0	0.00%	31	0.03%
Solar	15,343	63.45%	58,845	56.13%
Storage	3,196	13.22%	10,877	10.38%
Wind	1,343	5.55%	6,560	6.26%
Grand Total	24,182	100.00%	104,838	100.00%

Table 6.49: Virginia – Interconnection Requests by Fuel Type (Dec. 31 2020)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	8	718.9	2	35.0	10	753.9
	Diesel	0	0.0	0	0.0	0	0.0	2	2.1	2	20.2	4	22.3
	Natural Gas	4	1,621.0	0	0.0	4	2,679.0	46	7,269.4	43	17,246.8	97	28,816.2
	Nuclear	0	0.0	0	0.0	0	0.0	8	350.0	1	1,570.0	9	1,920.0
	Oil	0	0.0	0	0.0	0	0.0	6	322.2	2	40.0	8	362.2
	Other	0	0.0	0	0.0	0	0.0	1	0.0	2	136.3	3	136.3
	Storage	69	3,176.0	0	0.0	1	20.0	1	0.0	17	454.3	88	3,650.3
Renewable	Biomass	0	0.0	0	0.0	0	0.0	5	147.4	4	70.0	9	217.4
	Hydro	0	0.0	0	0.0	0	0.0	9	423.4	2	254.0	11	677.4
	Methane	0	0.0	0	0.0	0	0.0	15	100.4	11	81.8	26	182.2
	Solar	253	12,794.5	11	156.3	85	2,392.1	28	399.3	185	6,232.0	562	21,974.3
	Wind	9	1,323.9	1	9.4	1	9.9	1	1.5	31	886.2	43	2,230.9
	Wood	0	0.0	0	0.0	0	0.0	1	4.0	2	57.0	3	61.0
	Grand Total	335	18,915.5	12	165.7	91	5,101.0	131	9,738.7	304	27,083.5	873	61,004.3

Figure 6.56: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

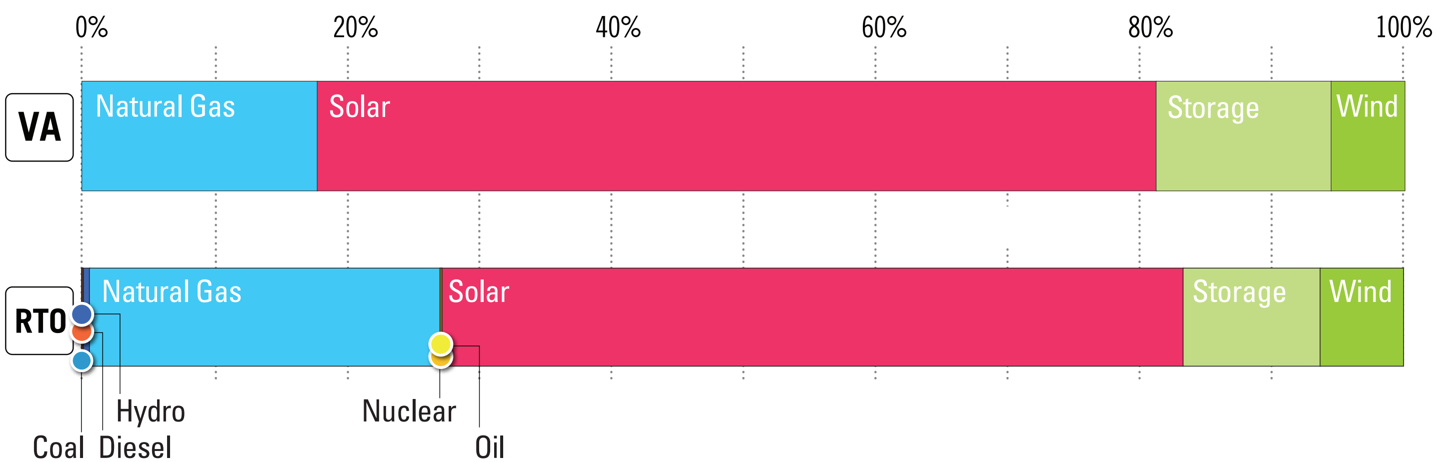
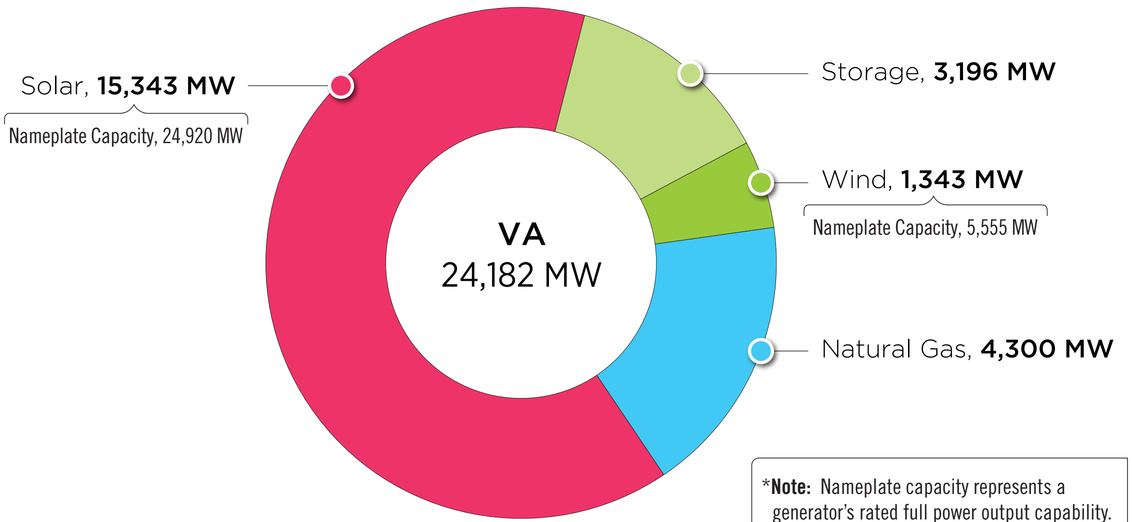
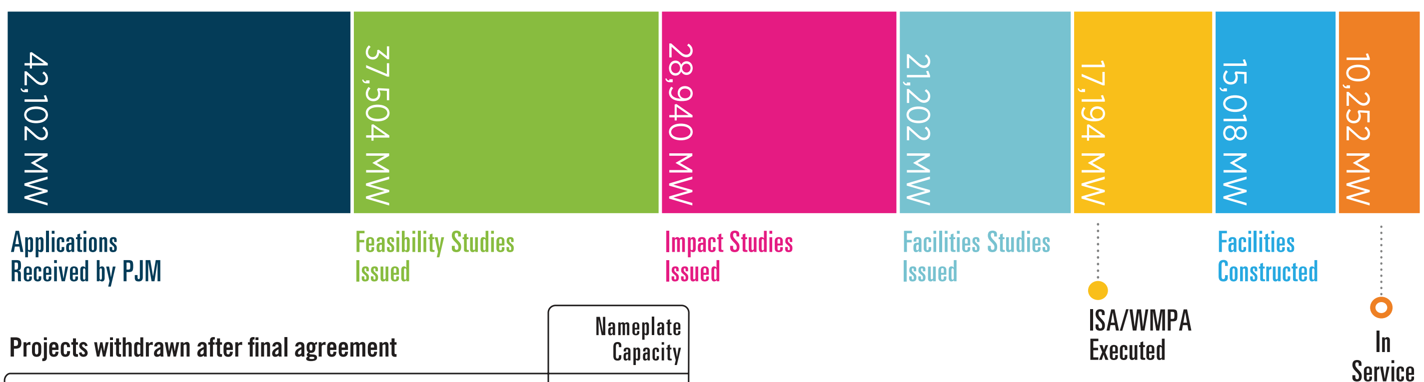


Figure 6.57: Virginia – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)



*****Note:** Nameplate capacity represents a generator's rated full power output capability.

Figure 6.58: Virginia Progression History of Queue – Interconnection Requests (Dec. 31, 2020)



Projects withdrawn after final agreement

			Nameplate Capacity
15	Interconnection Service Agreements	1,934 MW	2,275 MW
25	Wholesale Market Participation Agreements	243 MW	403 MW

Percentage of planned capacity and projects that have reached commercial operation	24% Requested capacity megawatts	27 % Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2020.

6.11.5 — Generation Deactivation

Known generating unit deactivation requests in Virginia between Jan. 1, 2020, and Dec. 31, 2020, are summarized in **Map 6.39** and **Table 6.50**.

Map 6.39: Virginia Generation Deactivations (Dec. 31, 2020)

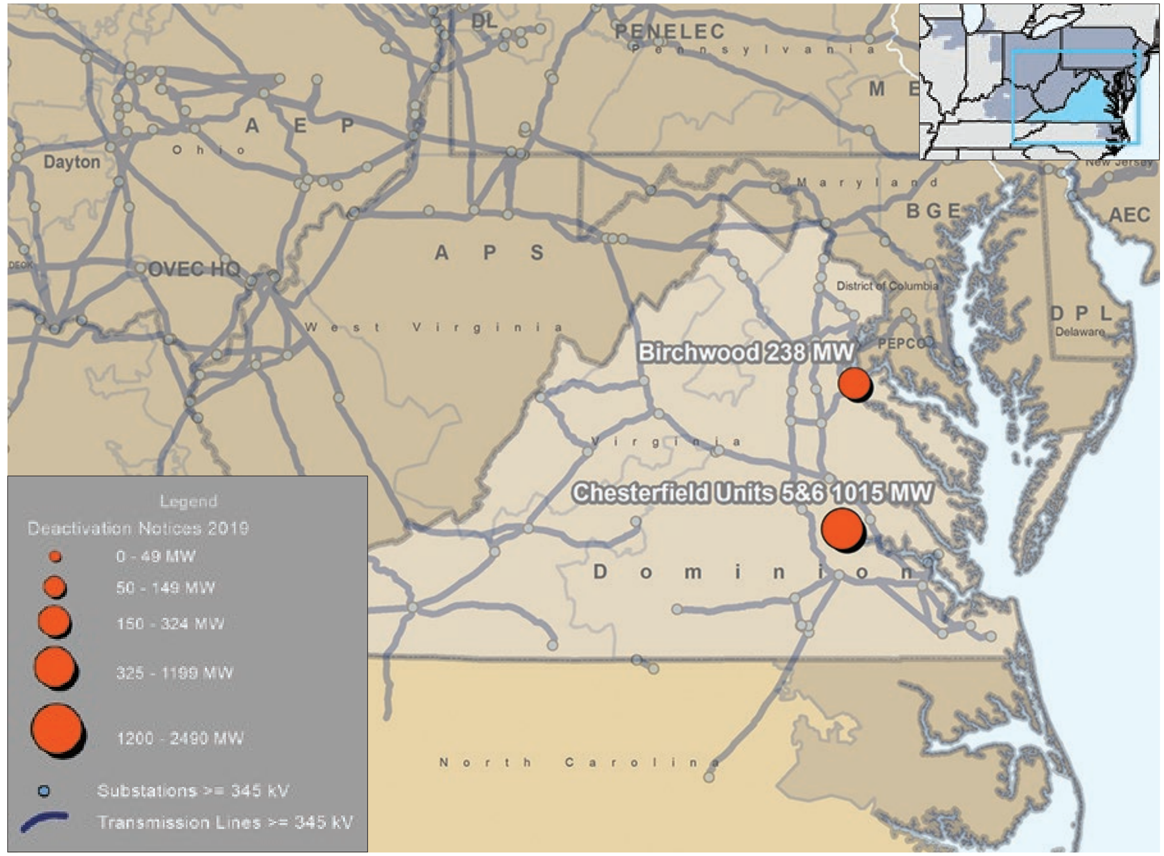


Table 6.50: Virginia Generation Deactivations (Dec. 31, 2020)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Birchwood Plant	Dominion	Coal	10/6/2020	3/1/2021	24	238.0
Chesterfield Unit 5			2/20/2020	5/31/2023	56	336.8
Chesterfield Unit 6			2/20/2020	5/31/2023	51	678.1

6.11.6 — Baseline Projects

2020 RTEP baseline projects greater than or equal to $10 million in Virginia are summarized in **Map 6.40** and **Table 6.51**.

Map 6.40: Virginia Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

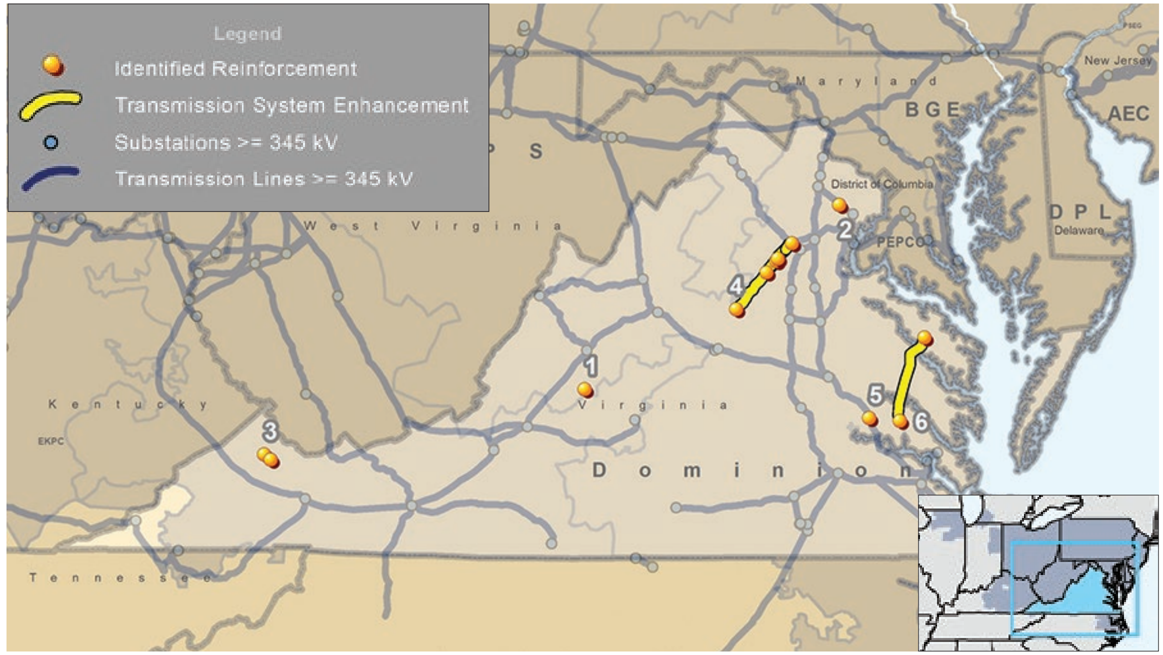


Table 6.51: Virginia Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3098	Rebuild Balcony Falls substation.	6/1/2019	$29.00	Dominion	5/21/2020
2	B3110	Replace the Clifton 230 kV breakers 201182 and XT2011 with 63 kA breakers.	12/31/2021	$15.47		8/4/2020
3	B3139	Rebuild the Garden Creek-Whetstone 69 kV line (~0.4 mile).	6/1/2023	$14.00	AEP	10/17/2019
4	B3162	Acquire land and build a new 230 kV switching station (Stevensburg) with a 224 MVA, 230/115 kV transformer. Gordonsville-Remington 230 kV (Line No. 2199) will be cut and connected to the new station. Remington-Mount Run 115 kV (Line No. 70) and Mount Run-Oak Green 115 kV (Line No. 2) will also be cut and connected to the new station.	6/1/2024	$22.00	Dominion	12/16/2019
5	B3213	Install second Chickahominy 500/230 kV transformer.	6/1/2023	$25.76		6/2/2020
6	B3223	Install a second 230 kV circuit with a minimum summer emergency rating of 1047 MVA between Lanexa and Northern Neck substations. The second circuit will utilize the vacant arms on the double-circuit structures that are being installed on the Line No. 224 (Lanexa-Northern Neck) end-of-life rebuild project (B3089). Expand the Northern Neck terminal from a 230 kV, four-breaker ring bus to a six-breaker ring bus. Expand the Lanexa terminal from a six-breaker ring bus to a breaker-and-a-half arrangement.		$23.00		9/1/2020

6.11.7 — Network Projects

No network projects greater than or equal to $10 million in Virginia were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.11.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in Virginia are summarized in **Map 6.41** and **Table 6.52**.

6.11.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in Virginia were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.41: Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

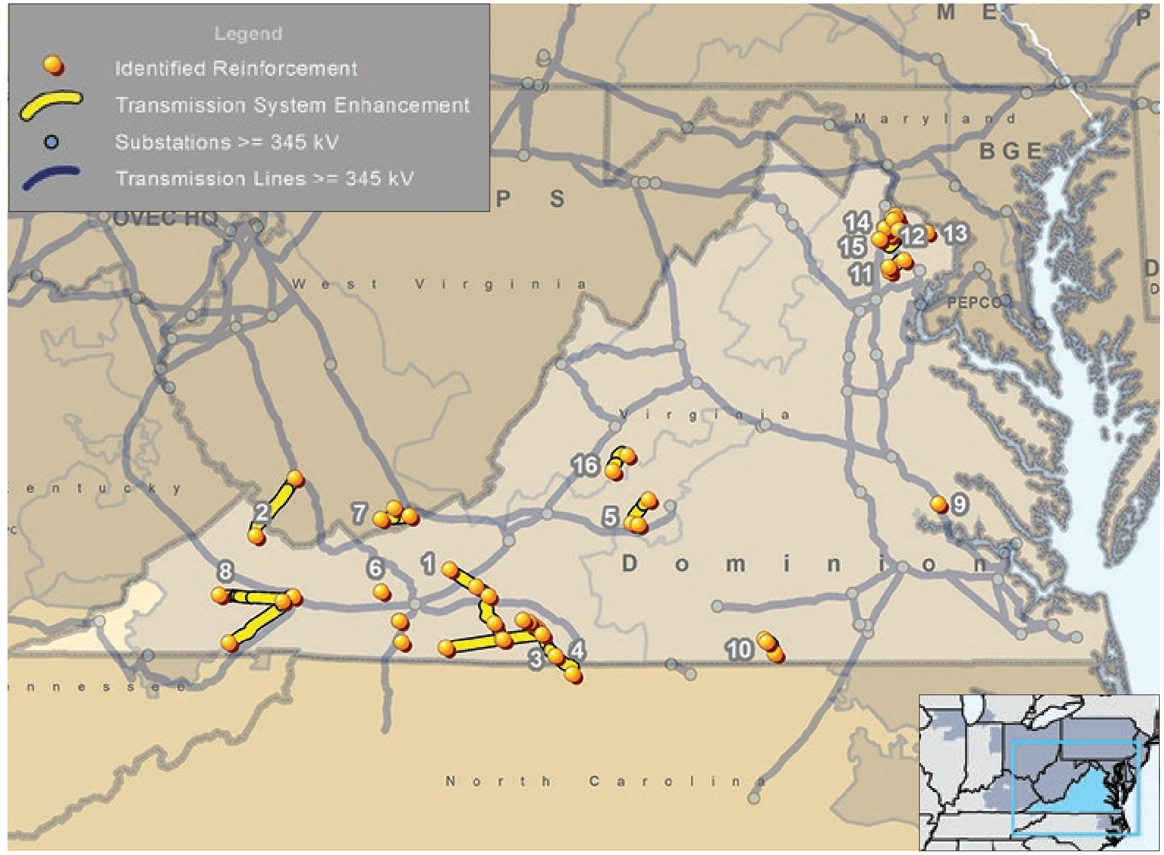


Table 6.52: Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2179	Construct ~12.5 miles of 138 kV line from Alum Ridge to Claytor.	11/1/2027	$326.90	AEP	1/17/2020
		Construct ~6.5 miles of 138 kV line from Alum Ridge to Floyd.	11/2/2026			
		Construct ~7 miles of 138 kV line from Fieldale to Fairystone.	9/2/2024			
		Construct ~1.25 miles of double-circuit 138 kV line to connect Stanleytown.	11/16/2026			
		Construct 0.07 miles of 138 kV line from Bassett Switch to Bassett.	6/1/2026			

Table 6.52: Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1 Cont.	S2179	Construct ~1.2 miles of 138 kV line from Philpott Dam to Fairystone.	10/31/2027	$326.90	AEP	1/17/2020
		Construct ~22 miles of 138 kV line from Salem Highway to Willis Gap.	7/1/2024			
		Construct ~21 miles of 138 kV line from Salem Highway to Fairystone.	10/31/2027			
		Construct ~11 miles of 138 kV line from Floyd to Woolwine.				
		Construct ~10 miles of 138 kV line from Salem Highway to Woolwine.	11/1/2024			
		Remove ~11 miles of 69 kV line from Floyd to Woolwine.	6/2/2025			
		Remove ~10 miles of 69 kV line from Stuart to Woolwine.	10/31/2027			
		Remove ~12.2 miles of 138 kV line from Alum Ridge to Claytor.	11/1/2027			
		Remove ~6.25 miles of 138 kV line from Alum Ridge to Floyd.	11/2/2026			
		Remove ~19 miles of 138 kV line from Floyd to West Bassett.	8/14/2026			
		Remove ~6.4 miles of 138 kV line from Fieldale to West Bassett.	6/15/2026			
		Remove ~0.34 miles of 138 kV line from Philpott substation to Philpott.	11/16/2026			
		Remove ~19 miles of 69 kV line from Fieldale to Stuart.	8/14/2026			
		Remove ~7.1 miles of 69 kV line from Fieldale to West Bassett.	6/15/2026			
		Remove ~6.8 miles of 69 kV line from Fieldale to West Bassett.				
		At Floyd station, install two 138 kV circuit breakers (3000 A 40 kA). Install high-side circuit switcher on Transformer 2 (3000A 40 kA). Station expansion to accommodate new equipment and drop-in control module. Install 138 kV line relaying, CCVT's, breaker controls, bus differential protection, Transformer No. 2 protection.	9/1/2025			
		At Fieldale station, retire 69 kV circuit breakers G, D and C. Install CCVTs and arresters on 138 kV West Bassett line.	11/13/2026			
		At Bassett switch, install 138 kV switch with two 138 kV MOABs.	6/1/2026			
		At Bassett station, convert station from 69 kV to 138 kV. Install 138/12 kV transformer with high-side circuit switcher, transclosure and associated distribution feeders.				
		At Claytor 138 kV station, install line relaying. Remove wavetrap. Replace 1590 AAC risers.	11/1/2027			
		Retire Philpott 138 kV switch structure.	11/16/2026			
		At Willis Gap station, install two 138 kV MOABs. Terminate new Salem Highway-Willis Gap 138 kV line.	6/3/2024			
		At Woolwine station, convert station from 69 kV to 138 kV. Retire/remove 69 kV switch structure, 69 kV MOABs and 69/34.5 kV transformer. Install 138 kV three-way switch structure with MOABs and 138/34.5 kV transformer with high-side circuit switcher.	11/1/2024			
		At Salem Highway station, establish new 138 kV station replacing Stuart station. Install 138 kV five-breaker ring bus, 138/34.5 kV & 138/12 kV transformers with high-side circuit switchers. Terminate Huffman, Floyd and Fairystone 138 kV circuits.	9/2/2024			
		At Stuart 69 kV station, retire and remove all existing equipment and control house.	6/2/2025			
		At Stanleytown station, convert station from 69 kV to 138 kV. Retire/remove 69 kV switch structure, 69 kV MOABs, 69/12 kV transformer. Install 138 kV three-way switch structure with MOABs and 138/12 kV transformer with high-side circuit switcher.	11/13/2026			

Table 6.52: Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1 Cont.	S2179	At Fairystone station, establish new 138 kV station replacing West Bassett. Install 138 kV, four-breaker ring bus, 138/34.5 kV transformer with high-side circuit switcher and associated distribution feeders. Terminate Salem Highway, Fieldale and Philpott Dam 138 kV circuits.	10/31/2027	$326.90	AEP	1/17/2020
		At Claudville station, establish new 138/34.5 kV distribution station with two 138 kV CBs, 138/34.5 kV transformer and three 34.5 kV feeders.				
		Provide transition, entry and termination for OPGW connectivity at Willis Gap, Claytor, Alum Ridge, Floyd, Woolwine, Stuart, Fairystone, Philpott Dam, Bassett, Stanleytown, Fieldale and Salem Highway to support fiber relaying.	7/1/2024			
2	S2189	Rebuild ~27.8 miles of the existing Baileysville–Hales Branch 138kV circuit.	8/1/2026	$98.50		2/21/2020
3	S2190	Rebuild approximately 15 miles of the AEP-owned portion of the 138 kV line between Fieldale and Dan River stations (AEP/Duke ownership changes at the border of North Carolina and Virginia).	10/31/2022	$32.20		
4	S2191	Construct ~5.75 miles of new double-circuit 138 kV line from the Fieldale-Ridgeway 138 kV circuit to a new Commonwealth Crossing station.	3/1/2020	$15.20		
		Establish a new 138/34.5 kV Commonwealth Crossing station with two 138 kV, 3000 A 40 kA circuit breakers, high-side 3000 A 40 kA circuit switcher, 138/34.5 kV, 30 MVA transformer and three 34.5 kV distribution feeders.				
		Install 5.75 miles of 48 count fiber between Commonwealth Crossing station and Ridgeway station to support SCADA and relaying.				
5	S2192	Rebuild 11.6 mile section of the Reusens-Altavista 138 kV line asset from Reusens to New London. ~5.5 miles consists of double-circuit 138 kV construction and ~6 miles consists of single-circuit 138 kV construction between Reusens and New London.	10/31/2022	$36.20		
		Install a 57.6 MVAR cap bank at Brush Tavern due to low-voltage concerns from operations during construction outages in the area.				
6	S2214	At Galax station, replace existing 69 kV circuit breakers F, G, and H with new 3000A 40 kA circuit breakers.	10/31/2022	$10.20		3/19/2020
		At Byllesby station, replace existing 69 kV circuit breakers B and D with new 3000A 40 kA circuit breakers.				
		At Jubal Early station, replace the existing 138/69/34.5 kV 75 MVA XFR with a new 138/69/34.5 kV 90 MVA XFR.				
		At Wythe station, replace existing 138/69 kV, 75 MVA XFR with a new 138/12 kV 20 MVA XFR, remove 69 kV CBs F and M, remove 69 kV bus and install 12 kV bus. Retire Lee Highway station and serve load from Wythe.				
7	S2226	Construct ~10 miles of new 138 kV line between Glen Lyn and Speedway. New right-of-way will be required for the new Glen Lyn-Speedway 138 kV line. Retire the existing section of line from Glen Lyn to Hatcher switch (~8 miles), including Hatcher switch.	5/1/2023	$55.40		
		Retire Hatcher switch. Install MOABs at Speedway on new line to Glen Lyn and existing line towards South Princeton. Install a circuit switcher on the Speedway transformer.				
		Rebuild ~7.3 miles of the Glen Lyn-South Princeton 138 kV circuit between Speedway station and the previous Hatcher switch.	12/1/2026			
8	S2250	Rebuild the existing Broadford-Wolf Hills/Clinch River-Saltville No. 2 138 kV double-circuit line (~26 miles) section between Saltville and Wolf Hills stations.	5/1/2024	$107.10		4/20/2020

Table 6.52: Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

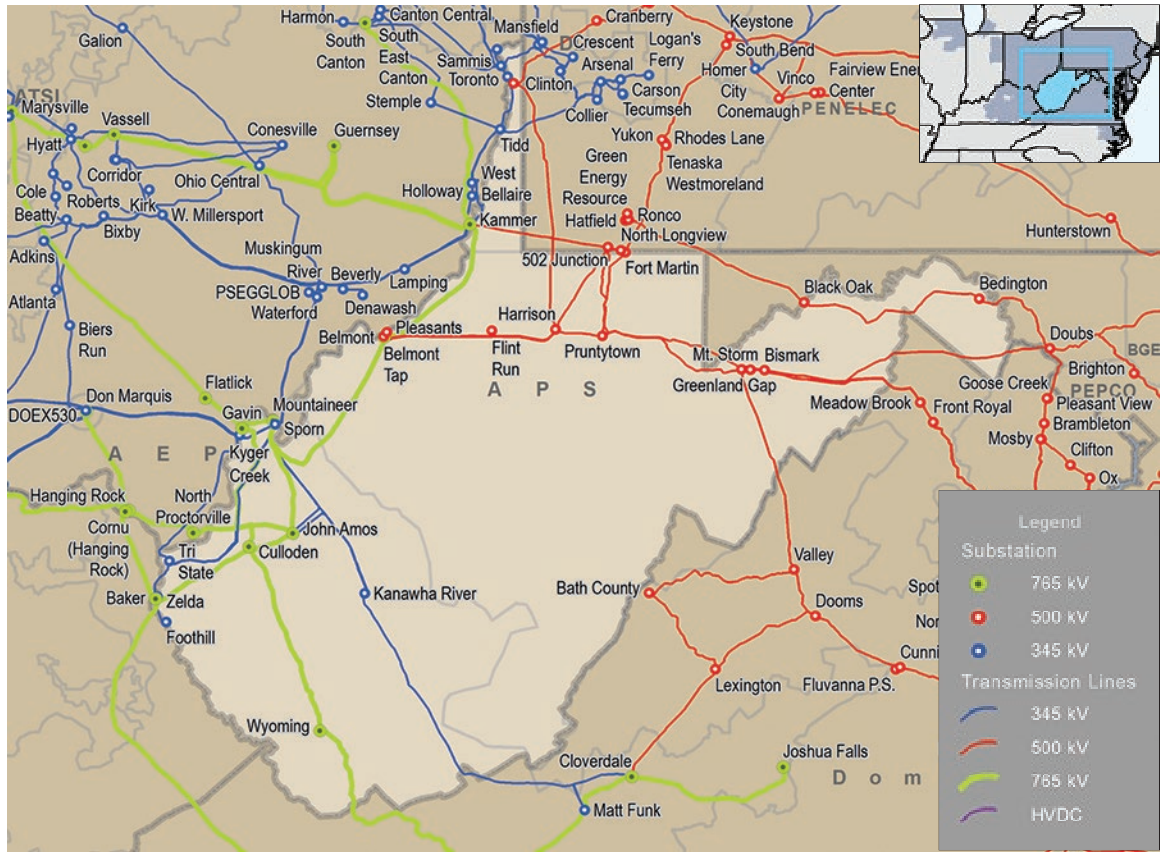
Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
9	S2319	Replace the three single phase 500/230 kV transformer banks and one spare bank with new units at Chickahominy.	9/30/2019	$14.10	Dominion	2/4/2020
10	S2320	Obtain land and build a 115 kV switching station (Cloud), adjacent to MEC's new Coleman Creek DP. Split Line No. 38 (Kerr Dam-Boydton Plank Rd.), extend a double-circuit 115 kV line for ~1.76 miles (new right-of-way) and terminate both lines into the new switching station. The switching station will consist of one breaker separating the two new lines. Provide one 115 kV line to serve MEC's new DP. Additionally, a 33 MVAR capacitor bank will be required at Herbert to provide additional voltage support.	11/30/2020	$16.00	Dominion	2/11/2020
11	S2321	Install a 1,200 amp, 50 kAIC circuit switcher and associated equipment (bus, switches, relaying, etc.) to feed the new transformer at Cloverhill.	6/1/2022	$17.75	Dominion	3/10/2020
11	S2321	Install a 1,200 amp, 50 kAIC circuit switcher and associated equipment (bus, switches, relaying, etc.) to feed the new transformer at Winters Branch.	1/1/2022	$17.75	Dominion	5/12/2020
11	S2321	Install a 1,200 amp, 50 kAIC circuit switcher and associated equipment (bus, switches, relaying, etc.) to feed the new transformer at Winters Branch.	3/1/2023	$17.75	Dominion	5/12/2020
11	S2321	Reconductor the 230 kV line No. 2011 from Clifton to Cannon Branch (7.54 miles) using a higher capacity conductor as well as terminal equipment upgrades to achieve an expected rating of 1574 MVA.	12/31/2025	$17.75	Dominion	10/6/2020
12	S2324	Interconnect the new Aviator substation by cutting and extending line No. 2137 (Poland-Shellhorn) ~0.5 miles to the proposed substation. Terminate both ends into a four-breaker ring arrangement to create an Aviator-Poland line and an Aviator-Shellhorn line. Dominion's standard high-ampacity conductor (bundled 768 ACSS; normal summer rating: 1572 MVA) will be used for the line extension.	12/15/2024	$22.00	Dominion	5/12/2020
13	S2326	Construct one 230 kV underground line from Tysons Substation to a new substation named Springhill substation to replace the portion of existing Ohio line No. 2010. Install a 230 kV, 50-100 MVAR variable shunt reactor at Tysons substation.	12/31/2025	$40.00	Dominion	5/12/2020
14	S2328	Install a 1,200 amp, 50 kAIC circuit switcher and associated equipment (bus, switches, relaying, etc.) to feed the new transformer at Waxpool.	10/1/2021	$29.30	Dominion	6/2/2020
14	S2328	Install a 1,200 amp, 50 kAIC circuit switcher and associated equipment (bus, switches, relaying, etc.) to feed the new transformer at Pacific.	12/15/2021	$29.30	Dominion	8/4/2020
14	S2328	Install a 1,200 amp, 40 kAIC circuit switcher and associated equipment (bus, switches, relaying, etc.) to feed the new transformer at Cumulus.	3/1/2022	$29.30	Dominion	8/4/2020
14	S2328	Reconductor the 230 kV line 2152 from Beaumeade to Nimbus (2.16 miles) using a higher capacity conductor as well as terminal equipment upgrades to achieve an expected rating of 1574 MVA.	12/31/2025	$29.30	Dominion	10/6/2020
14	S2328	Reconductor the 230 kV line 9173 from Nimbus to Buttermilk (0.94 miles) using a higher capacity conductor as well as terminal equipment upgrades to achieve an expected rating of 1574 MVA.	12/31/2025	$29.30	Dominion	10/6/2020
14	S2328	Reconductor the 230 kV line 9185 from Beaumeade to Paragon Park (1.0 miles) using a higher capacity conductor as well as terminal equipment upgrades to achieve an expected rating of 1574 MVA.	12/31/2025	$29.30	Dominion	10/6/2020
14	S2328	Reconductor the 230 kV line 2209 from Evergreen Mills to Yardley Ridge (0.16 miles) using a higher capacity conductor as well as terminal equipment upgrades to achieve an expected rating of 1574 MVA.	12/31/2025	$29.30	Dominion	10/6/2020
14	S2328	Reconductor the 230 kV line 2095 from Cabin Run to Shellhorn (4.73 miles) using a higher capacity conductor as well as terminal equipment upgrades to achieve an expected rating of 1574 MVA.	12/31/2025	$29.30	Dominion	10/6/2020
15	S2329	Interconnect the new substation Lincoln Park by cutting and extending line No. 2008 (Dulles-Loudoun) and line No. 2143 (Discovery-Reston) to the proposed substation. Lines to terminate in a six-breaker ring arrangement.	9/1/2023	$10.47	Dominion	6/2/2020
15	S2329	Replace 50 kAIC Clifton L282 breaker with 63 kAIC model.	6/1/2025	$10.47	Dominion	10/6/2020
16	S2337	Rebuild ~9.771 miles of line No. 26, between Balcony Falls and Buena Vista, to current 115 kV standards and with a minimum rating of 261 MVA.	12/31/2024	$20.00	Dominion	8/13/2020

6.12: West Virginia RTEP Summary

6.12.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in West Virginia, including facilities owned and operated by Allegheny Power (AP) and American Electric Power (AEP) as shown on **Map 6.42**. West Virginia's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

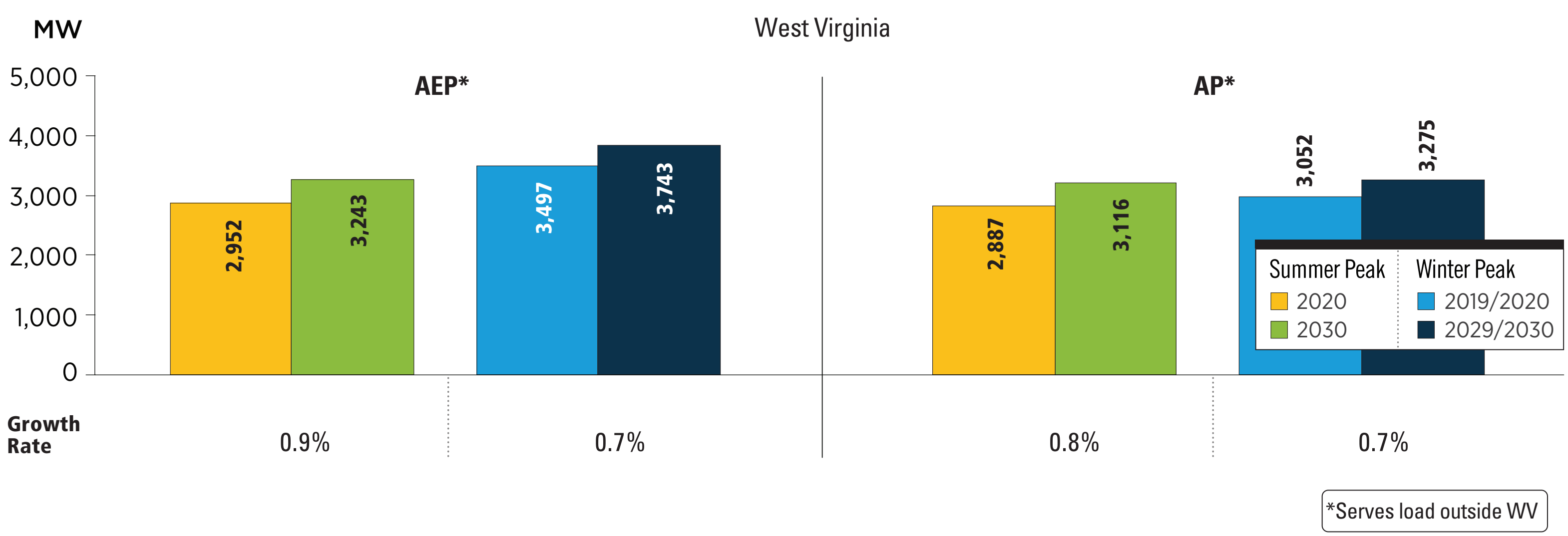
Map 6.42: PJM Service Area in West Virginia



6.12.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.59** summarizes the expected loads within the state of West Virgina and across all of PJM.

Figure 6.59: West Virginia – 2020 Load Forecast Report



PJM RTO Summer Peak

2020: **148,092** MW
2030: **157,132** MW
Growth Rate 0.6%

PJM RTO Winter Peak

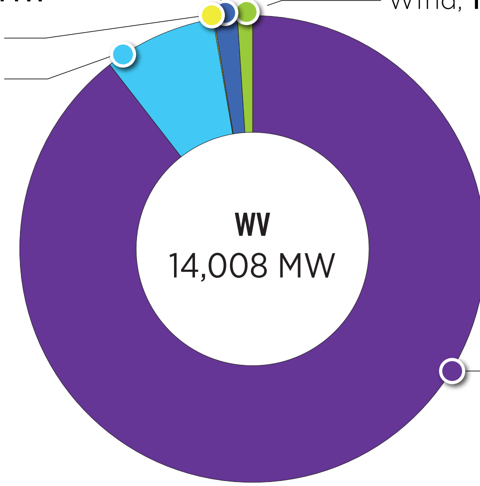
2019/2020: **131,287** MW
2029/2030: **139,970** MW
Growth Rate 0.6%

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in the noted state. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.12.3 — Existing Generation

Existing generation in West Virginia as of Dec. 31, 2020, is shown by fuel type in **Figure 6.60**.

Figure 6.60: West Virginia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



6.12.4 — Interconnection Requests

PJM markets continue to attract generation proposals in West Virginia, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in West Virginia, as of Dec. 31, 2020, 38 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.53**, **Table 6.54**, **Figure 6.61**, **Figure 6.62** and **Figure 6.63**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.53: West Virginia – Capacity by Fuel Type – Interconnection Requests (Dec. 31. 2020)

	West Virginia Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	36	1.07%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	30	0.89%	559	0.53%
Natural Gas	1,885	56.00%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	0	0.00%	31	0.03%
Solar	1,317	39.11%	58,845	56.13%
Storage	60	1.78%	10,877	10.38%
Wind	39	1.15%	6,560	6.26%
Grand Total	**3,366**	**100.00%**	**104,838**	**100.00%**

Table 6.54: West Virginia – Interconnection Requests by Fuel Type (Dec. 31 2021)

		In Queue						Complete					
		Active		Suspended		Under Construction		In Service		Withdrawn		Grand Total	
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	1	36.0	10	861.0	7	2,023.0	18	2,920.0
	Natural Gas	2	1,285.0	3	600.0	0	0.0	6	409.7	43	16,140.8	54	18,435.5
	Nuclear	0	0.0	0	0.0	0	0.0	0	0.0	2	66.0	2	66.0
	Other	3	54.2	1	5.8	1	0.0	2	0.0	3	18.0	10	78.0
	Storage	0	0.0	0	0.0	0	0.0	0	0.0	2	48.0	2	48.0
Renewable	Biomass	1	30.0	0	0.0	0	0.0	5	59.2	12	208.8	18	298.0
	Hydro	0	0.0	0	0.0	0	0.0	3	5.6	3	13.8	6	19.4
	Methane	23	1,316.7	0	0.0	0	0.0	0	0.0	4	44.2	27	1,360.9
	Solar	2	23.5	0	0.0	1	15.1	10	197.5	26	414.8	39	650.9
	Wind	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
	Grand Total	31	2,709.4	4	605.8	3	51.1	36	1,533.0	102	18,977.4	176	23,876.7

Figure 6.61: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

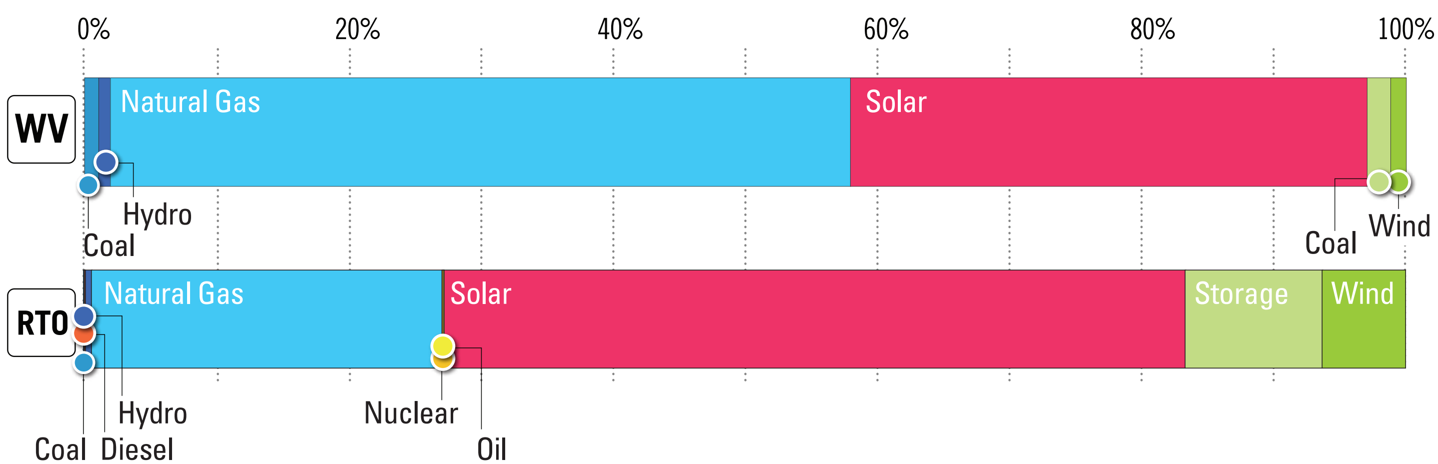


Figure 6.62: West Virginia – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)

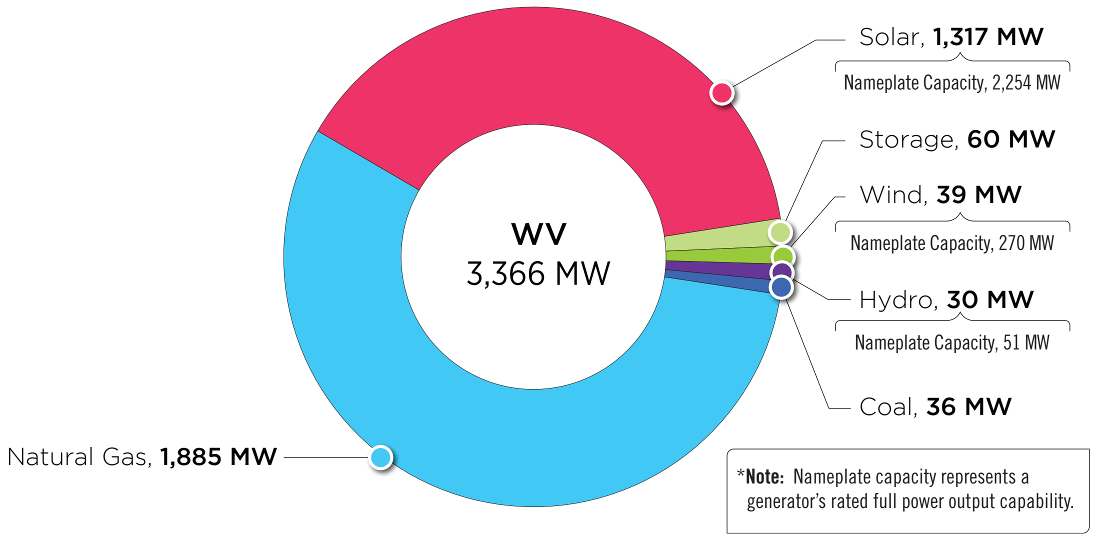


Figure 6.63: West Virginia Progression History of Queue – Interconnection Requests (Dec. 31, 2020)

Projects withdrawn after final agreement			Nameplate Capacity
12	Interconnection Service Agreements	1,499 MW	1,951 MW
2	Wholesale Market Participation Agreements	6 MW	11 MW

Percentage of planned capacity and projects that have reached commercial operation	7% Requested capacity megawatts	25 % Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2020.

6.12.5 — Generation Deactivation

There were no known generating unit deactivation requests in West Virginia between Jan. 1, 2020, and Dec. 31, 2020, as part of the 2020 RTEP.

6.12.6 — Baseline Projects

2020 RTEP baseline projects greater than or equal to $10 million in West Virginia are summarized in **Map 6.43** and **Table 6.55**.

6.12.7 — Network Projects

No network projects greater than or equal to $10 million in West Virginia were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.43: West Virginia Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

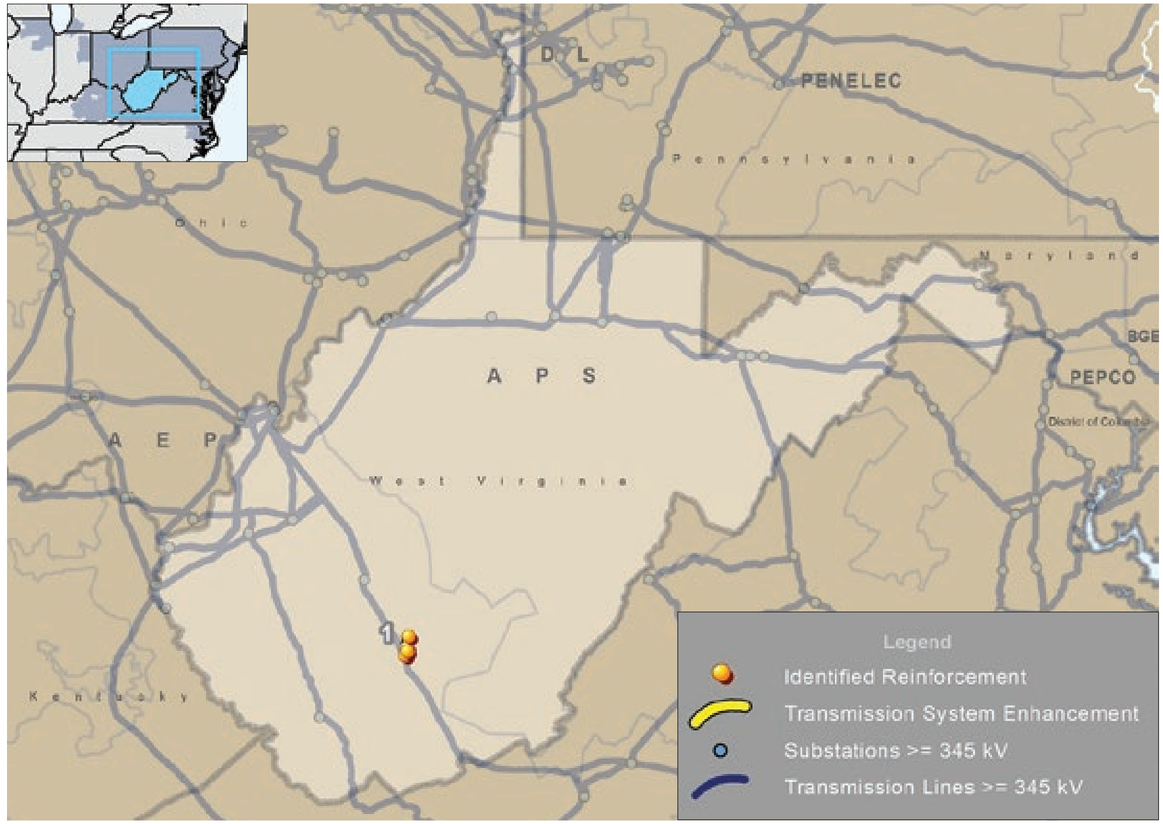


Table 6.55: West Virginia Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3148	Rebuild the 46 kV Bradley-Scarbro line to 96 kV standards using 795 ACSR to achieve a minimum rater of 120 MVA. Rebuild the new line adjacent to the existing one leaving the old line in service until the work is completed.	12/1/2021	$27.70	AEP	10/25/2019
		Bradley remote-end station work, replace 46 kV bus, install new 12 MVAR capacitor bank.				
		Replace the existing switch at Sun substation with a two-way SCADA-controlled MOAB switch.				
		Remote end work and associated equipment at Scarbro station.				
		Retire Mt. Hope station and transfer load to existing Sun station.				

6.12.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in West Virginia are summarized in **Map 6.44** and **Table 6.56**.

6.12.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in West Virginia were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.44: West Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

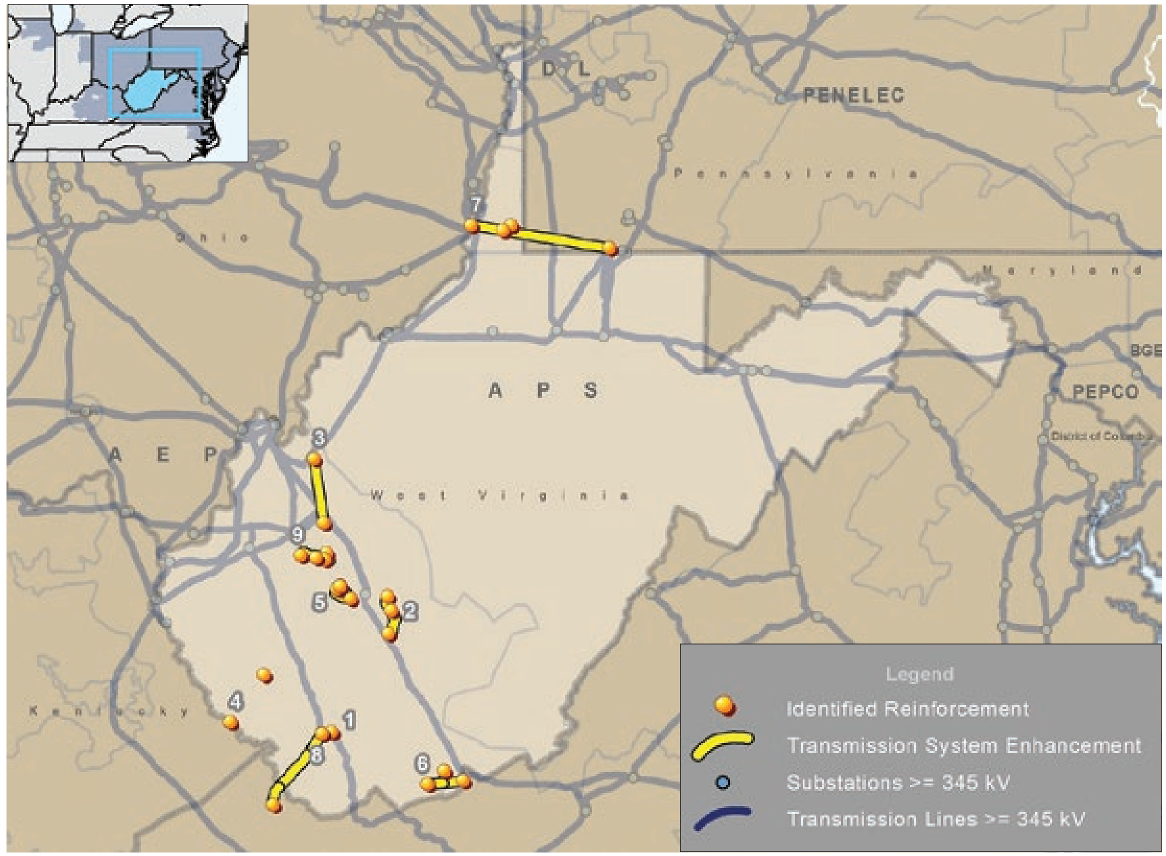


Table 6.56: West Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S1497	Expand Guyandotte 138 kV station, install new 138 kV switch, circuit switcher and 138/12 kV transformer to allow for retirement of Marianna station.	6/1/2021	$78.50	AEP	11/20/2020

Table 6.56: West Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2	S2177	Rebuild the Carbondale-Kincaid 46 kV line as a single-circuit 46 kV line (~16.3 miles).	6/1/2023	$76.50	AEP	1/17/2020
		Retire the Carbondale-Kincaid No. 1/No. 2 double-circuit 46 kV line.				
		Alloy station: Install a two-way switch to address hard tap.				
		Page substation: Replace existing switch to accommodate new line.				
		Raynes Meter station: Remove/retire station.				
		Boomer station: Remove/retire station.				
		Carbondale station: Replace existing circuit breakers A and G with two new 69 kV circuit breakers. Replace existing 46 kV circuit breakers B, C and F. Retire 46 kV circuit breaker D. Install two new 138 kV circuit breakers and a high-side circuit switcher. Replace existing 138/69/46 kV, 115 MVA transformer with a new 138/69/46 kV, 130 MVA transformer. 138 kV line work needed to accommodate the station work.				
		Kincaid station: Replace existing circuit breakers A and B with two new 46 kV circuit breakers. Retire circuit breaker J. Replace existing ground transformer bank with a new ground transformer bank. Install a new high side circuit switcher to replace the existing ground switch. MOAB on the high side of the transformer.				
3	S2178	Construct a new 138 kV line (~11.5 mi.) from Kenna to the existing Ripley 138 kV station.	11/17/2023	$61.70		1/17/2020
		Construct a new 138 kV line (~10 mi.) from Kenna to the existing Sisson 138 kV station.				
		Install three new 138 kV circuit breakers at Sisson and perform remote end relaying work at Amos station.				
		Install 138 kV bus and two new 138 kV circuit breakers at Kenna.				
		Install one new 138 kV circuit breaker at Ripley.				
4	S2189	Rebuild ~27.8 miles of the existing Baileysville-Hales Branch 138kV circuit.	8/1/2026	$98.50		2/21/2020
5	S2225	Retire the existing 7.5-mile long Belle-Cabin Creek No. 1 and No. 2 circuits from Belle to Cabin Creek.	4/1/2023	$41.80		3/19/2020
		Construct new double-circuit 46 kV line (designed to 138 kV) from Belle to Hernshaw (~4 miles).				
		At Hernshaw station, install four new circuit breakers, 3000 A 40 kA, 46 kV (138 kV design) in a ring configuration. Install two new 138/46 kV, 90 MVA transformers at Hernshaw with two circuit breakers, 3000 A 40 kA, 138 kV, on the high side of each new transformer.				
		Remote end work and retire circuit breakers AA and AB at Cabin Creek station.				
		Install Chesapeake 46 kV substation to eliminate existing hard tap currently serving Praxair. Install a new line extension to Praxair (0.2 miles).				
		Replace the existing switches at Marmet Station to accommodate the new line construction.				
		Marmet hydro hard tap will be relocated to be positioned between 46 kV circuit breaker G at Belle and the new switches at Marmet station. Remote end work required at Marmet hydro station.				
		Belle Station work to replace CCVTs with new 46 kV PTs and upgrade line surge arresters.				
6	S2226	Construct ~10 miles of new 138 kV line between Glen Lyn and Speedway. New right-of-way will be required for the new Glen Lyn-Speedway 138 kV line. Retire the existing section of line from Glen Lyn to Hatcher switch (~8 miles), including Hatcher switch.	5/1/2023	$55.40		3/19/2020
		Retire Hatcher switch. Install MOABs at Speedway on new line to Glen Lyn and existing line towards South Princeton. Install a circuit switcher on the Speedway transformer.				
		Rebuild ~7.3 miles of the Glen Lyn-South Princeton 138 kV circuit between Speedway station and the previous Hatcher switch.	12/1/2026			

Table 6.56: West Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
7	S2270	Construct a new 500-138 kV station (Panhandle), connecting to the Kammer-502 Junction 500 kV circuit (~10.3 miles from Kammer, 31.7 miles from 502 Junction). Install a three-breaker 500 kV ring bus; 450 MVA 500-138 kV transformer; three-breaker 138 kV ring bus.	3/1/2022	$68.70	AEP	5/12/2020
		Construct a new 138 kV switching station (Nauvoo Ridge) with eight 138 kV breakers in a breaker-and-a-half design. The station will have one circuit to Gosney Hill, two circuits to the customer's facility, two circuits to Panhandle, and a 23 MVAR, 138 kV cap bank.				
		At Gosney Hill, install a new 138 kV breaker toward Nauvoo Ridge. Update station protection. Replace the 795 AAC risers and strain bus with 2000 AAC risers.				
		Construct a new 4.7-mile, 138kV line south of Gosney Hill station to Nauvoo Ridge. Utilize 1033 ACSR conductor. Acquire new right-of-way.				
		Construct a new 1.3 mile, double-circuit 138 kV line from Nauvoo Ridge to the customer's substation. Acquire new right-of-way.				
		Construct a new 1.5 mile, double-circuit 138 kV line from Panhandle to Nauvoo Ridge. Utilize 1033 ACSR conductor for each circuit. Acquire new right-of-way.				
		Extend the Kammer-502 Junction 500 kV transmission line 0.1 mile into Panhandle station (0.2 mile total).				
8	S2346	Replace existing 138 kV CBs G, H, I, K, L and N with six new 138 kV, 40 kA circuit breakers. Replace existing 138 kV cap bank BB and install a new 138 kV breaker on the new cap bank. Replace existing 46 kV cap bank switcher with a new cap bank switcher. Install a high-side circuit switcher on the existing 138/46 kV transformer. Upgrades will be made to the existing road into the station to improve access and space constraints. A flood wall will be installed to mitigate flooding concerns. Note: 138 kV CS CC failed and has been replaced.	7/1/2022	$10.10	AEP	7/17/2020
9	S2348	At Chemical station, replace existing 138/46 kV, 45 MVA transformers No. 1 and No. 2 with two new 138/46 kV, 90 MVA transformers and install two 138 kV high-side circuit switchers on each transformer. Retire 138/46 kV transformer No. 4. Retire 46 kV, 18 MVAR capacitor and switcher DD. Retire 46 kV bus No. 1, bus No. 2 and bus No. 3. Rebuild the 46 kV into a fourteen-breaker ring configuration. Replace grounding banks No. 7 and No. 8.	10/17/2022	$35.30	AEP	7/17/2020
		Line work is required to accommodate the new station configuration on the Chemical-Turner 138 kV line and Chemical-Chesterfield 46 kV line.				
		Remote-end work is required at Turner station, Central Avenue station and Ward Hollow stations.				
		Rebuild the Chemical-South Charleston No. 1 and Chemical-South Charleston No. 2 46 kV lines with a new double-circuit 46 kV line (69 kV standards) from Chemical-Criel Mound.				
		At South Charleston, retire the existing circuit breakers A and B and install four new 46 kV, 40 kA circuit breakers in a ring at a new station (Criel Mound) adjacent to the existing South Charleston station.				

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Appendix 1: TO Zones and Locational Deliverability Areas

1.0: TO Zones and Locational Deliverability Areas

The terms transmission owner zone and Locational Deliverability Area, as used in this report, are defined below and shown on **Map 1.1**. They are provided for the convenience of the reader based on definitions from other sources.

A transmission owner (TO) is a PJM member that owns transmission facilities or leases with rights equivalent to ownership in transmission facilities. Taking transmission service is not sufficient to qualify a member as a TO. Schedule 15 of the Reliability Assurance Agreement defines the distinct zones that the PJM control area comprises and is available on the PJM website.

A Locational Deliverability Area (LDA) is an electrically cohesive area defined by transmission zones, parts of zones or combination of zones. LDAs are used as part of PJM's RTEP process load deliverability test. They are restated in **Table 1.1** below for ease of reference.

Map 1.1: Locational Deliverability Areas

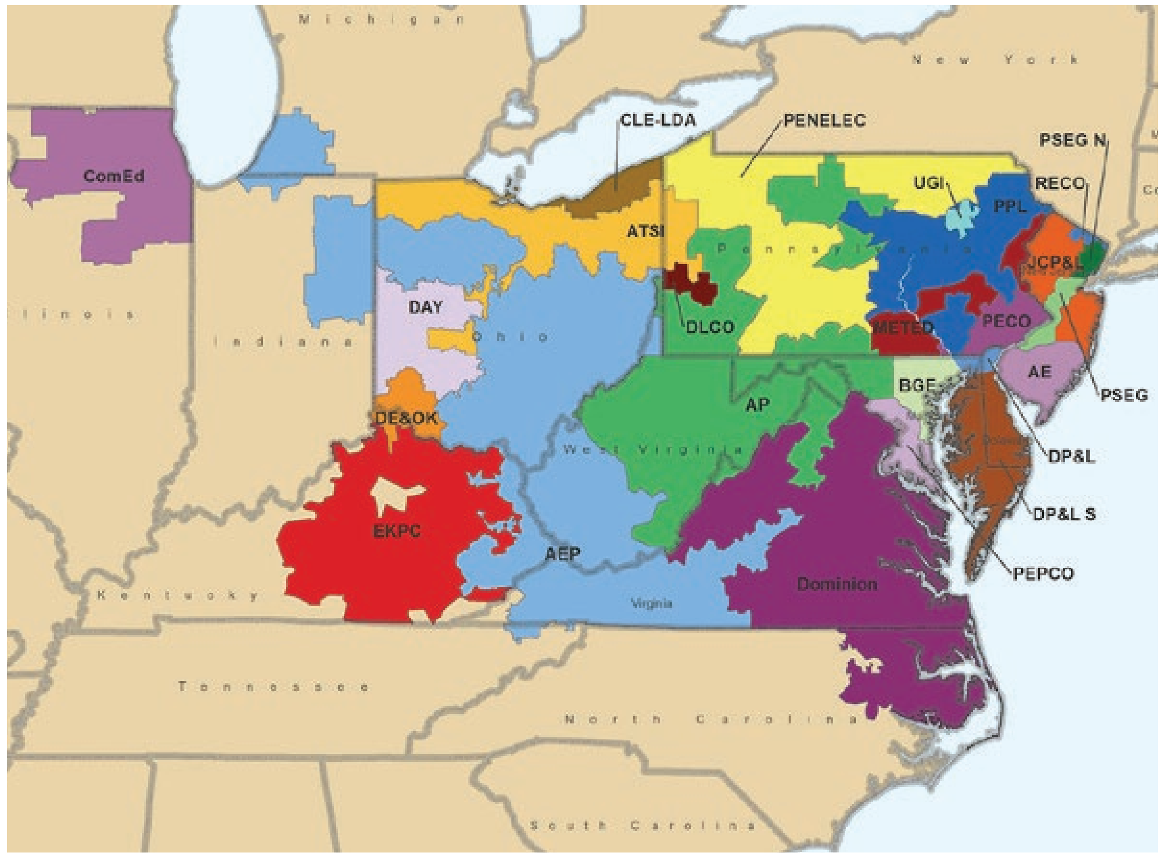

Table 1.1: Locational Deliverability Areas

Entity Name	TO Zone	LDA	Description
AE	▲	▲	Atlantic City Electric Co.
AEP	▲	▲	American Electric Power
AP	▲	▲	Allegheny Power
ATSI	▲	▲	American Transmission Systems, Inc.
BGE	▲	▲	Baltimore Gas and Electric Co.
Cleveland	n/a	▲	Cleveland Area
ComEd	▲	▲	Commonwealth Edison Co.
DAY	▲	▲	Dayton Power & Light Co.
DEO&K	▲	▲	Duke Energy Ohio and Kentucky Corp.
DLCO	▲	▲	Duquesne Light Co.
Dominion	▲	▲	Dominion
DP&L	▲	▲	Delmarva Power & Light Co.
Delmarva South	n/a	▲	Southern Portion of DP&L
EKPC	▲	▲	East Kentucky Power Cooperative
JCP&L	▲	▲	Jersey Central Power & Light
METED	▲	▲	Met-Ed
Mid-Atlantic	n/a	▲	Global Area – PENELEC, METED, JCP&L, PPL, PECO, PSEG, BGE, PEPCO, AE, DP&L, RECO
PECO	▲	▲	PECO Energy Co.
PENELEC	▲	▲	Pennsylvania Electric Co.
PEPCO	▲	▲	Potomac Electric Power Co.
PPL	▲	▲	PPL Electric Utilities and UGI Utilities
PSEG	▲	▲	PSEG
PSEG North	n/a	▲	Northern Portion of PSEG
Southern Mid-Atlantic	n/a	▲	Global area – BGE and PEPCO
Western Mid-Atlantic	n/a	▲	Global Area – PENELEC, METED, PPL
Western PJM	n/a	▲	Global Area – AP, AEP, DAY, DLCO, ComEd, ATSI, DEO&K, EKPC, OVEC

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Glossary

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The terms and concepts in this glossary are provided for the convenience of the reader and are in large part based on definitions from other sources, as indicated in the "Reference" column for each term.

These references include the following:

- **Mxx:** PJM Manual
- **NERC:** North American Electric Reliability Corporation
- **OA:** PJM Operating Agreement
- **OATT:** PJM Open Access Transmission Tariff
- **RAA:** Reliability Assurance Agreement

Term	Reference	Acronym	Definition
Aluminum Conductor Steel Reinforced		ACSR	This high-capacity, stranded conductor type is typically made with a core of steel (for its strength properties), surrounded by concentric layers of aluminum (for its conductive properties).
Aluminum Conductor Steel Supported		ACSS	This high-capacity, stranded conductor type is made from annealed aluminum.
Adequacy	NERC		Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency. "Resources" refers to a combination of electricity generation and transmission facilities, which produce and deliver electricity, and "demand response" programs, which reduce customer demand for electricity. Maintaining adequacy requires system operators and planners to take into account scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand.
Ancillary Service	OATT		Ancillary services are those services necessary to support the transmission of capacity and energy from resources to loads while, in accordance with good utility practice, maintaining reliable operation of the transmission provider's transmission system.
Attachment Facilities	OATT		Attachment facilities are necessary to physically connect a customer facility to the transmission system or interconnected distribution facilities.
Auction Revenue Right	OA	ARR	An auction revenue right is a financial instrument entitling its holder to auction revenue from financial transmission rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the annual FTR auction.
Available Transfer Capability	NERC	ATC	The available transfer capability is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.
Base Capacity Resource	M18		Base capacity resources are capacity resources that are not capable of sustained, predictable operation throughout the entire delivery year. These resources will only be procured through the 2019/2020 Delivery Year, at which point all resources will be Capacity Performance resources starting with the 2020/2021 Delivery Year. See "Capacity Performance."
Baseline Upgrades	M14B		In developing the RTEP, PJM tests the baseline adequacy of the transmission system to deliver energy and capacity resources to each load in the PJM region. The system (as planned to accommodate forecast demand, committed resources and commitments for firm transmission service for a specified time frame) is tested for compliance with NERC and the applicable regional reliability council (ReliabilityFirst or SERC) standards, nuclear plant licensee requirements, PJM reliability standards and PJM design standards. Areas not in compliance with the standards are identified, and enhancement plans to achieve compliance are developed. Baseline expansion plans serve as the base system for conducting feasibility studies and system impact studies for all proposed requests for generation and merchant transmission interconnection, and for long-term firm transmission service.

Term	Reference	Acronym	Definition
Behind-The-Meter Generation	OATT	BTM	Behind-the-meter generation delivers energy to load without using the transmission system or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of PJM). Behind-the-meter generation does not include (1) at any time, any portion of such generating unit's capacity that is designated as a capacity resource, or (2) in an hour, any portion of the output of such generating unit(s) that is sold to another entity for consumption at another electrical location or in to the PJM Interchange Energy Market.
Bilateral Transaction	OA		A bilateral transaction is a contractual arrangement between two entities (one or both being PJM members) for the sale and delivery of a service.
Breaker-and-a-Half		BAAH	This substation configuration type is typically composed of two main sections connected by element strings. Each element string is composed of circuit breakers, transformers or line elements.
Bulk Electric System	NERC; M14B	BES	ReliabilityFirst defines the bulk electric system as all individual generation resources larger than 20 MVA, or a generation plant with aggregate capacity greater than 75 MVA that is connected via a step-up transformer(s) to facilities operated at voltages of 100 kV or higher, lines operated at voltages of 100 kV or higher, associated auxiliary and protection and control system equipment that could automatically trip a BES facility, independent of the protection and control equipment's voltage level (assuming correct operation of the equipment). The ReliabilityFirst BES definition excludes: (1) Radial facilities connected to load-serving facilities or individual generation resources smaller than 20 MVA, or a generation plant with aggregate capacity less than 75 MVA where the failure of the radial facilities will not adversely affect the reliable steady-state operation of other facilities operated at voltages of 100 kV or higher; (2) the balance of generating plant control and operation functions (other than protection systems that directly control the unit itself and step-up transformer), which would include relays and systems that automatically trip a unit for boiler, turbine, environmental and/or other plant restrictions; and (3) all other facilities operated at voltages below 100 kV.
Capacitor Voltage Transformer		CCVT	This type of transformer is used to step down high voltage signals and provide a low voltage signal for metering or protection devices.
Capacity Emergency	M13		A capacity emergency is a system condition where operating capacity plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet the total of its demand, firm sales and regulating requirements.
Capacity Emergency Transfer Limit	RAA, M14B, M18	CETL	The capacity emergency transfer limit is part of load deliverability analysis used to determine the maximum limit, expressed in megawatts, of a study area's import capability, under the conditions specified in the load deliverability criteria.
Capacity Emergency Transfer Objective	RAA; M14B, M18, M20	CETO	The CETO is the emergency import capability, expressed in megawatts, required of a PJM subregion area to satisfy established reliability criteria.
Capacity Interconnection Rights	OATT	CIRs	Capacity interconnection rights are rights to input generation as a capacity resource into the transmission system at the point of interconnection, where the generating facilities connect to the transmission system.
Capacity Performance			Capacity Performance is a set of rules governing resource participation in the Reliability Pricing Model (RPM). Following a series of transition auctions, Capacity Performance rules will be fully in place starting with the 2020/2021 Delivery Year. See "Base Capacity Resource" and "Capacity Performance Resource."
Capacity Performance Resource	M18		Capacity Performance resources are capable of sustained, predictable operation throughout the entire delivery year. All resources will be Capacity Performance resources starting with the 2020/2021 Delivery Year. See "Capacity Performance."
Capacity Resource	RAA. M14A, M14B		Capacity resources are megawatts of net capacity from existing or planned generation resources or load reduction capability provided by demand resources or interruptible load for reliability (ILR) in the region PJM serves.
Circuit Breaker		CB	This automatic device is used to stop the flow of current in an electric circuit as a safety measure.
Clean Air Interstate Rule		CAIR	The Clean Air Interstate Rule is an Environmental Protection Agency (EPA) rule regarding the interstate transport of soot and smog.
Clean Power Plan		CPP	The Clean Power Plan is an EPA rule regarding carbon pollution from power plants.
Coincident Peak	M19		The coincident peak is a zone's contribution to the RTO or higher level locational deliverability area (LDA) peak load.
Combined Cycle (Turbine)		CC/CCT	This type of turbine is a generating unit facility that generally consists of a gas-fired turbine and a heat recovery steam generator. Electricity is produced by a gas turbine whose exhaust is recovered to heat water, yielding steam for a steam turbine that produces still more electricity.
Combustion Turbine		CT	A combustion turbine is a generating unit in which a combustion turbine engine is the prime mover.
Consolidated Transmission Owners Agreement	PJM.com	CTOA	The Consolidated Transmission Owners Agreement is an agreement between transmission owners, which PJM is a signatory to, establishing the rights and commitments of all parties involved.

Term	Reference	Acronym	Definition
Contingency			A contingency is the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Coordinated System Plan		CSP	A Coordinated System Plan (CSP) contains the results of coordinated PJM/MISO studies required to assure the reliable, efficient and effective operation of the transmission system. The CSP also includes the study results for interconnection requests and long-term firm transmission service requests. Further description of CSP development can be found in the PJM/MISO Joint Operating Agreement.
Cost of New Entry	M18	CONE	The cost of new entry is a Reliability Pricing Model (RPM) capacity market parameter defined as the levelized annual cost in installed capacity $/MW-day of a reference combustion turbine to be built in a specific locational deliverability area.
Cross-State Air Pollution Rule		CSAPR	The Cross-State Air Pollution Rule is an EPA rule regarding reduction in air pollution related to power plant emissions.
Cross-Linked Polyethylene		XLPE	Type of plastic used to insulate power lines; benefits include resistance to temperature fluctuations and other environmental factors.
Current Transformer		CT	This type of transformer is used to measure electrical flows for telemetry purposes.
Deactivation	M14D		Deactivation encompasses retiring or mothballing a generating unit governed by the PJM Open Access Transmission Tariff. Any generator owner, or designated agent, who wishes to retire a unit from PJM operations must initiate a deactivation request in writing no less than 90 days in advance of the planned deactivation date.
Deliverability	RAA, M14B, M18		Deliverability is a test of the physical capability of the transmission network for transfer capability to deliver energy from generation facilities to wherever it is needed to ensure only that the transmission system is adequate for delivery of energy to load under prescribed conditions. The testing procedure includes two components: (1) generation deliverability and (2) load deliverability.
Demand Resource	M18	DR	See “Load Management.”
Designated Entity			A designated entity can be an existing transmission owner or non-incumbent transmission developer designated by PJM with the responsibility to construct, own, operate, maintain and finance immediate-need reliability projects, short-term projects, long-lead projects, or economic-based enhancements or expansions.
Designated Entity Agreement	OATT	DEA	When a project is designated as a greenfield project that is not reserved for the transmission owner, execution of a Designated Entity Agreement (DEA) is required. The DEA defines the terms, duties, accountabilities and obligations of each party, and relevant project information, including project milestones. Once construction is complete and the designated entity has met all DEA requirements, the agreement is no longer needed. The designated entity must execute the Consolidated Transmission Owners Agreement as a requirement for DEA termination. Once a project is energized, a designated entity that is not already a transmission owner must become a transmission owner, subject to the Consolidated Transmission Owners Agreement.
Distributed Solar Generation			Distributed solar generation is not connected to PJM, and does not participate in PJM markets. These resources do not go through the full interconnection queue process. The output of these resources is netted directly with the load. PJM does not receive metered production data from any of these resources.
Distribution Factor		DFAX	A distribution factor is the portion of an imposed power transfer that flows across a specified transmission facility or interface.
Diversity	M18		Diversity is the number of megawatts that account for the difference between a transmission owner zone’s forecasted peak load at the time of its own peak and its coincident load at the time of the PJM peak.
Eastern Interconnection Planning Collaborative		EIPC	The Eastern Interconnection Planning Collaborative (EIPC) represents an interconnection-wide transmission planning coordination effort among planning authorities in the Eastern Interconnection. EIPC consists of 20 planning coordinators comprising approximately 95 percent of the Eastern Interconnection electricity demand. EIPC coordinates analysis of regional transmission plans to ensure their coordination, and also provides the resources to conduct analysis of emerging issues affecting the grid.
Eastern Interconnection Reliability Assessment Group		ERAG	The ERAG is a group whose purpose is to further augment the reliability of the bulk power system in the Eastern Interconnection through periodic studies of seasonal and longer-term transmission system conditions.
Eastern MAAC	M14B	EMAAC	Eastern MAAC is a term used in PJM deliverability analysis to refer to the portion of PJM that includes AE, DPL, JCP&L, PECO, PSE&G and Rockland.
Effective Forced Outage Rate on Demand	M22	EFORd	EFORd is a measure of the probability that a generating unit will not be available due to forced outages or forced de-ratings when there is a demand on the unit to generate. See Manual 22: Generator Resource Performance Indices for the equation.
Electrical Distribution Company		EDC	An electrical distribution company owns and/or operates electrical distribution facilities for the delivery of electrical energy to end-use customers.

Term	Reference	Acronym	Definition
End-Use Characteristics	M19		End-use characteristics are the measures of electrical equipment and appliance efficiency used in residential and commercial settings. These are represented in forecast models as part of heating, cooling and other applications.
Energy Efficiency Programs		EE	Energy efficiency programs are incentives or requirements at the state or federal level that promote energy conservation and the wise use of energy resources.
Energy Resource	M14A, M14B		An energy resource is a generating facility that is not a capacity resource.
Extra High Voltage		EHV	Extra high voltage transmission equipment operates at 230 kV and above.
Facilities Study Agreement	M14A	FSA	A facilities study agreement is an agreement made between the interconnection customer/developer and PJM to identify the scope of facility additions and upgrades to be included in the interconnection study.
Fault			A fault is a physical condition that results in the failure of a component or facility within the transmission system to transmit electrical power in the manner for which it was designed.
Federal Energy Regulatory Commission		FERC	FERC is an independent federal agency that regulates the interstate transmission of electricity, natural gas and oil.
Financial Transmission Right	M6	FTR	A financial transmission right is a financial instrument entitling the holder to receive revenues based on transmission congestion, measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.
Firm Transmission Service	OATT		Firm transmission service is intended to be available at all times to the maximum extent practical. Service availability is subject to system emergency conditions, unanticipated facility failure or other unanticipated events and is governed by Part II of the OATT.
Flexible Alternating Current Transmission System		FACTS	FACTS is a system composed of static equipment used for the AC transmission of electrical energy, meant to enhance controllability and increase power transfer capability of the network. It is generally a power electronics-based system.
Fixed Series Capacitor		FSC	A fixed series capacitor is a grouping of capacitors used to reduce transfer reactances on bulk transmission corridors.
Flowgate			A flowgate is a specific combination of a monitored facility and a contingency which impacts that monitored facility.
Gas-Insulated Substation		GIS	This is a high voltage substation in which the major electrical components are contained within a sealed environment with sulfur hexafluoride gas as the insulating medium.
Generation Deliverability	M14B		Generation deliverability is the ability of the transmission system to export capacity resources from one electrical area to the remainder of PJM. The generator deliverability test for reliability analysis ensures that, consistent with the load deliverability single contingency testing procedure, the transmission system is capable of delivering the aggregate system generating capacity at peak load with all firm transmission uses modeled.
Generator Step-up Transformer		GSU	A GSU transformer "steps-up" generator power output voltage level to the suitable grid-level voltage for transmission of electricity to load centers.
Geomagnetically Induced Current		GIC	This is a manifestation at ground level of space weather; these currents impact the normal operation of electrical conductor systems.
Good Utility Practice	OATT		Good Utility Practice is any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be practices, methods or acts generally accepted in the region.
Group/Gang Operated Air Break		GOAB	A group/gang operated air break is the portion of a circuit breaker that opens and closes to allow or block current to flow through or not. This particular type of break uses air as a dielectric medium, as opposed to others which use gas, oil or air contained within a vacuum. "Gang operated" refers to a mechanical linkage that opens and closes the disconnect.
Horizontal Directional Drilling		HDD	Horizontal directional drilling technology for laying transmission cable employs a long, flexible drill bit to bore horizontally underground. This is a trenchless method in which no surface excavation is required, except for drill entry and exit points, which minimizes surface restoration, ecological disturbances and environmental impacts. By contrast, jet-plowing techniques affect the riverbed over the length of the installation.
Independent State Agencies Committee	PJM.com	ISAC	The ISAC is a voluntary, stand-alone committee that consists of members from regulatory and other state agencies representing all of the states and the District of Columbia within the service territory of PJM. The ISAC is an independent committee that is not controlled or directed by PJM, the PJM Board or PJM members. The purpose of the ISAC is to provide PJM with input and scenarios for transmission planning studies.

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Term	Reference	Acronym	Definition
Independent System Operator		ISO	An independent system operator is an entity that is authorized to operate an electric transmission system and is independent of any influence from the owner(s) of that electric transmission system. See also "RTO."
Installed Capacity		ICAP	Installed capacity is valued based on the summer net dependable rating of the unit as determined in accordance with PJM rules and procedures relating to the determination of generating capacity.
Interconnected Reliability Operating Limit	M14B	IROL	The interconnected reliability operating limit is a system operating limit that, if violated, could lead to instability, uncontrolled separation or cascading outages that adversely impact the reliability of the bulk electric system.
Interconnection Construction Service Agreement	M14C	ICSA	The ICSA is a companion agreement to the ISA and is necessary for projects that require the construction of interconnection facilities as defined in the ISA. The ICSA details the project scope, construction responsibilities of the involved parties, ownership of transmission and customer interconnection facilities and the schedule of major construction work.
Interconnection Coordination Agreement	OATT	ICA	An interconnection coordination agreement is made between transmission owners and/or transmission developers outlining the schedules and responsibilities of each party involved.
Interconnection Service Agreement	M14A	ISA	An interconnection service agreement is made among the transmission provider, an interconnection customer and an interconnected transmission owner regarding interconnection under Part IV and Part VI of the Tariff.
Interregional Market Efficiency Project		IMEP	Interregional proposals are designed to address congestion and its associated costs along the MISO/PJM border within the context of the MISO/PJM JOA as identified in long-term market efficiency simulation results.
Joint RTO Planning Committee		JRPC	The JRPC is the decision-making body for MISO/PJM coordinated system planning as governed by the MISO/PJM Joint Operating Agreement.
Light Load Reliability Analysis	M14B		Light load reliability analysis ensures that the transmission system is capable of delivering the system generating capacity during a light load situation (50% of 50/50 summer peak demand level).
Load			Load refers to demand for electricity at a given time, expressed in megawatts.
Load Analysis Subcommittee	M19	LAS	The Load Analysis Subcommittee is responsible for technical analysis and coordination of information related to the electric peak demand and energy forecasts, interruptible load resources for capacity, credit and weather, and peak load studies. The LAS reports to the Planning Committee.
Load Deliverability	M14B		Load deliverability is the ability of the transmission system to deliver energy from the aggregate of available capacity resources in one PJM electrical area and adjacent non-PJM areas to another PJM electrical area that is experiencing a capacity deficiency.
Load Management	M18	LM	Load management is the ability to interrupt retail customer load at the request of PJM. Such a PJM request is considered an emergency action and is implemented prior to a voltage reduction. Load management derives a demand resource or interruptible-load-for-reliability credit in RPM.
Load Serving Entity	RAA, OATT	LSE	Load serving entities (LSE) provide electricity to retail customers. LSEs include traditional distribution utilities.
Local Distribution Company		LDC	A local distribution company (LDC) is a regulated utility involved in the delivery of natural gas to consumers within a specific geographic area. While some large industrial, commercial and electric generation customers receive natural gas directly from high-capacity pipelines, most other users receive natural gas from their LDCs.
Locational Deliverability Area	M14B	LDA	Locational deliverability areas are electrically cohesive load areas, historically defined by transmission owner service territories and larger geographical zones comprising a number of those service areas.
Locational Marginal Price		LMP	The locational marginal price is the hourly integrated market clearing marginal price for energy at the location the energy is delivered or received.
Loss-of-Load Expectation	M14B	LOLE	Loss-of-load expectation defines the adequacy of capacity for the entire PJM footprint based on load exceeding available capacity, on average, during only one day in 10 years.
Market Participant			A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met credit requirements as established by PJM. Market buyers are able to make purchases and market sellers are able to make sales in PJM energy and capacity markets.
Maximum Facility Output	M14A, M14G	MFO	This term refers to the maximum amount of power a generator is capable of producing.
Megavolt-Ampere Reactive	OA	MVAR	See "Reactive Power."

Term	Reference	Acronym	Definition
Merchant Transmission Facility	OATT		Merchant transmission facilities are AC or DC transmission facilities that are interconnected with, or added to, the transmission system in accordance with the PJM Open Access Transmission Tariff. These facilities are not existing facilities within the transmission system, transmission facilities included in the rate base of a public utility on which a regulated return is earned, or transmission facilities included in previous RTEPs or customer interconnection facilities.
Mercury and Air Toxins Standards		MATS	MATS is an EPA rule limiting the emissions of toxic air pollutants like mercury, arsenic and metals from power plant emissions.
Mid-Atlantic Subregion	M14B	MAAC	The PJM Mid-Atlantic Subregion encompasses 12 transmission owner zones: Atlantic City Electric Company (AE), Baltimore Gas and Electric Co. (BGE), Delmarva Power and Light (DP&L), Jersey Central Power & Light Co. (JCP&L), Met-Ed (METED), Neptune Regional Transmission System (Neptune RTS), PECO Energy Co. (PECO), Pennsylvania Electric Company (PENELEC), Potomac Electric Power Company (PEPCO), PPL Electric Utilities (PPL), PSEG and Rockland Electric Co. (Rockland). The Neptune Regional Transmission System interconnects with the Mid-Atlantic PJM transmission system at Sayreville substation in northern New Jersey.
MISO Transmission Expansion Planning		MTEP	MTEP is the Midcontinent Independent System Operator (MISO) plan for enhancing the future of the power grid in their area.
Motor-Operated Air Break		MOAB	A motor-operated air break is the portion of a circuit breaker that opens and closes to allow or block current. This particular type of break uses air as a dielectric medium, as opposed to others that use gas, oil or air contained within a vacuum. “Motor operated” refers to a remote-controlled motorized linkage that opens and closes the disconnect.
Multiregional Model Working Group		MMWG	The Multiregional Model Working Group reports to the ERAG and is responsible for developing all Eastern Interconnection power flow and dynamic base case models, including seasonal updates to summer and winter power flow study cases.
National Renewable Energy Laboratory		NREL	The NREL, part of the Department of Energy, is a federal laboratory dedicated to research and the development, commercialization and deployment of renewable energy and energy efficiency technologies.
Network Reinforcements	OATT		Network reinforcements are modifications or additions to transmission-related facilities that are integrated with and support the transmission provider’s overall transmission system for the general benefit of all users of such transmission system.
Non-Coincident Peak	M19	NCP	The non-coincident peak is a zone’s individual peak load.
North American Electric Reliability Corporation	NERC	NERC	NERC is a FERC-appointed body whose mission is to ensure the reliability of the bulk power system.
Open Access Same-Time Information System		OASIS	The Open Access Same-Time Information System (OASIS) provides information by electronic means about available transmission capability for point-to-point service and a process for requesting transmission service on a non-discriminatory basis. OASIS enables transmission providers and transmission customers to communicate requests and responses to buy and sell available transmission capacity offered under the PJM Open Access Transmission Tariff.
Open Access Transmission Tariff	OATT	OATT	The OATT is a FERC-filed tariff specifying the terms and conditions under which PJM provides transmission service and carries out its generation and merchant transmission interconnection process.
Optical Grounding Wire Communications		OPGW	This is a type of fiber optic cable that is used in the construction of electric power transmission and distribution lines and that combines the functions of grounding and communications.
Optimal Power Flow		OPF	Optimal power flow is a tool used to determine optimal dispatch, subject to transmission constraints. Optimal often means most economical but may also mean “minimum control change.”
Organization of PJM States, Inc.		OPSI	OPSI refers to an organization of statutory regulatory agencies in the 13 states and the District of Columbia within which PJM Interconnection operates. OPSI member regulatory agencies’ activities include, but are not limited to, coordinating activities such as data collection, issues analysis and policy formulation related to PJM, its operations, its market monitor and matters related to FERC, as well as their individual roles as statutory regulators within their respective state boundaries.
PJM Manuals			PJM Manuals contain the instructions, rules, procedures and guidelines established by PJM for the operation, planning and accounting requirements of the region PJM serves and the PJM Interchange Energy Market.
PJM Member	OA, M33		A PJM member is any entity that has satisfied PJM requirements to conduct business with PJM, including transmission owners, generating entities, load-serving entities and marketers.
Planning Committee	OA	PC	The Planning Committee was established under the Operating Agreement to review and recommend system planning strategies and policies, as well as planning and engineering designs for the PJM bulk power supply system.

Term	Reference	Acronym	Definition
Planning Cycle	M14B		The planning cycle is the annual RTEP process, including a series of studies, analysis, assessments and related supporting functions.
Planning Horizon	M14B		The planning horizon is the future time period over which system transmission expansion plans are developed based on forecasted conditions.
Probabilistic Risk Assessment	M14B	PRA	PJM assesses risk exposure using a Probabilistic Risk Assessment (PRA) risk management tool. The goal of the PRA model is to minimize asset service cost. PJM's PRA method integrates the economics of facility loss with the likelihood of that loss occurring.
Reactive Power (expressed in MVAR)	M14A		Reactive power is the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers or electrostatic equipment such as capacitors and directly influences electric system voltage. Reactive power is usually expressed as megavolt-ampere reactive (MVAR).
Regional Greenhouse Gas Initiative		RGGI	States and provinces in the northeastern United States and eastern Canada adopted the Regional Greenhouse Gas Initiative to reduce greenhouse gas emissions.
Regional RTEP Project	M14B, OA		A regional RTEP project is a transmission expansion or enhancement at a voltage level of 100 kV or higher.
Regional Transmission Expansion Plan	M14B	RTEP	The Regional Transmission Expansion Plan (RTEP) is prepared by PJM pursuant to Schedule 6 of the PJM Operating Agreement for the enhancement and expansion of the transmission system in order to meet the demands for firm transmission service in the region PJM serves.
Regional Transmission Organization	FERC	RTO	A regional transmission organization is an independent, FERC-approved organization of sufficient regional scope, which coordinates the interstate movement of electricity under FERC-approved tariffs by operating the transmission system and competitive wholesale electricity markets, and ensures reliability and efficiency through expansion planning and interregional coordination.
Reliability	NERC		A reliable bulk power system is one that is able to meet the electricity needs of end-use customers, even when unexpected equipment failures or other factors reduce the amount of available electricity.
Reliability Assurance Agreement	RAA	RAA	The Reliability Assurance Agreement (RAA) among load-serving entities in the region PJM serves is intended to ensure that adequate capacity resources will be planned and made available to provide reliable service to loads within PJM, to assist other parties during emergencies and to coordinate planning of capacity resources consistent with the reliability principles and standards.
Reliability Must Run		RMR	A reliability must run (RMR) generating unit is one slated to be retired by its owners but is needed to be available to maintain reliability. Typically, it is requested to remain operational beyond its proposed retirement date until required transmission enhancements are completed.
Reliability Pricing Model		RPM	The Reliability Pricing Model (RPM) is PJM's resource adequacy construct. The purpose of RPM is to develop a long-term pricing signal for capacity resources and load serving entity obligations that is consistent with the PJM RTEP process. RPM adds stability and a locational nature to the pricing signal for capacity.
ReliabilityFirst Corporation		RFC	ReliabilityFirst is a not-for-profit company incorporated in the state of Delaware, whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory. ReliabilityFirst was approved by the North American Electric Reliability Corporation (NERC) to become one of eight Regional Reliability Councils in North America and began operations on Jan. 1, 2006. ReliabilityFirst is the successor organization to three former NERC Regional Reliability Councils: the Mid-Atlantic Area Council, the East Central Area Coordination Agreement and the Mid-American Interconnected Network.
Renewable Integration Study		RIS	The RIS is an ongoing study to examine the reliability and market impacts of high wind and solar penetration in the PJM system to meet objectives of state policies regarding renewable resource production.
Renewable Portfolio Standard		RPS	The Renewable Portfolio Standard is a set of guidelines or requirements at the state or federal level requiring energy suppliers to provide specified amounts of electric energy from eligible renewable energy resources.
Right of First Refusal		ROFR or RFR	The right of first refusal is a contractual right that gives the holder the option to enter a business transaction with the owner of an asset, according to specified terms, before the owner is entitled to enter into that transaction with a third party.
Right-of-Way		ROW	A right-of-way is a corridor of land on which electric lines may be located. The transmission owner may own the land in fee; own an easement; or have certain franchise, prescription or license rights to construct and maintain lines.
Security	NERC		The ability of the bulk power system to withstand sudden, unexpected disturbances such as short circuits or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by physical or cyber attacks. The bulk power system must be planned, designed, built and operated in a manner that takes into account these modern threats, as well as more traditional risks to security.

Term	Reference	Acronym	Definition
Security Constrained Optimal Power Flow		SCOPF	The optimal power flow determines the ideal dispatch, subject to transmission constraints. Optimal usually means "least cost" (or most economical), but may also mean "minimum control change." Security-constrained OPF, or SCOPF, adds contingencies. The SCOPF will seek a single dispatch that does not cause any overloads in the base case, nor any overloads during any of the contingencies.
Southern Subregion	M14B		The PJM Southern Subregion comprises one transmission owner zone – Dominion (Dominion).
Special Protection System	M03	SPS	A Special Protection System (SPS) also known as a remedial action scheme, includes an assembly of protection devices designed to detect and initiate automatic action in response to abnormal or pre-defined system conditions. The intent of these schemes is generally to protect equipment from thermal overload or to protect against system instability following subsequent contingencies on the electric system. Redundant assemblies may be applied for the above functions on an individual facility – in such cases, each assembly is considered a separate protection system. An SPS consists of protection devices such as relays, current transformers, potential transformers, communication interface equipment, communication links, breaker trip and close coils, switch gear auxiliary switches and all associated connections.
Static Synchronous Compensator		STATCOM	A shunt device of the Flexible AC Transmission System (FACTS) family that uses power electronics to control power flow and improve transient stability on power grids.
System Operating Limit	M14B	SOL	The value (such as MW, MVAR, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within applicable reliability criteria. System operating limits are based upon certain operating criteria.
Static Var Compensation		SVC	An SVC device rapidly and continuously provides reactive power required to control dynamic voltage swings under various system conditions, improving power system transmission and distribution performance.
Subregional RTEP Committee	M14B, OA		This PJM committee facilitates the development and review of the subregional RTEP projects. The Subregional RTEP Committee is responsible for the initial review of the subregional RTEP projects, and for providing recommendations to the Transmission Expansion Advisory Committee concerning the subregional RTEP projects.
Subregional RTEP Project	M14B, OA		A subregional RTEP project is defined in the PJM Operating Agreement as a transmission expansion or enhancement rated below 230 kV.
Sub-Synchronous Resonance		SSR	Power system sub-synchronous resonance (SSR) is the build-up of mechanical oscillations in a turbine shaft arising from the electro-mechanical interaction between the turbine generator and the rest of the power system. This can lead to turbine shaft damage, or even catastrophic loss. The term "sub-synchronous" refers to the fact that the oscillations a shaft can experience occur at levels below 60 Hz (cycles-per-second).
Supplemental Project	M14B, OA		"Supplemental Project" replaces the term "Transmission Owner Initiated or TOI Project" and refers to a regional RTEP project or a subregional RTEP project that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.
Surge Impedance Loading		SIL	The megawatt loading of a transmission line at which a natural reactive power balance occurs. A line loaded below its SIL supplies reactive power to the system; a line above its SIL absorbs reactive power.
System Stability			Stability studies examine the grid's ability to return to a stable operating point following a system fault or similar disturbance. Such contingencies can cause a nearby generator's rotor position to change in relation to the stator's magnetic field, affecting the generator's ability to maintain synchronism with the grid. Power system engineers measure this stability in terms of generator bus voltage and maximum observed angular displacement between a generator's rotor axis and the stator magnetic field. Stability in actual operations is affected by machine megawatt, system voltage, machine voltage, duration of the disturbance and system impedance. Transient stability examines this phenomenon over the first several seconds following a system disturbance.
Targeted Market Efficiency Project		TMEP	TMEP interregional projects address historical congestion on reciprocal coordinated flowgates – a set of specific flowgates subject to joint and common market congestion management.
Temperature-Humidity Index	M19	THI	The temperature-humidity index (THI) gives a single numerical value in the general range of 70–80, reflecting the outdoor atmospheric conditions of temperature and humidity during warm weather. The THI is defined as follows: THI = Td – (0.55 – 0.55RH) * (Td - 58), where Td is the dry-bulb temperature and RH is the percentage of relative humidity, when Td is greater than or equal to 58.
Thyristor Controlled Series Compensator		TCSC	A thyristor-controlled series compensator is a series capacitor bank that is shunted by a thyristor controlled reactor.
Topology	M14B		Topology is a geographically based or other diagrammatic representation of the physical features of an electrical system or portion of an electrical system – including transmission lines, transformers, substations, capacitors and other power system elements – that in aggregate constitute a transmission system model for power flow and economic analysis.

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Term	Reference	Acronym	Definition
Transmission Customer	M14A, M14B, M2, OATT		A transmission customer is any eligible customer, or its designated agent, that (i) executes a service agreement or (ii) requests in writing that PJM file with FERC, a proposed, unexecuted service agreement to receive transmission service under Part II of the PJM OATT.
Transmission Expansion Advisory Committee	M14B	TEAC	The Transmission Expansion Advisory Committee was established by PJM to provide advice and recommendations to aid in the development of the RTEP.
Transmission Loading Relief	M03	TLR	Transmission loading relief is a NERC procedure developed for the Eastern Interconnection to mitigate overloads on the transmission system by allowing reliability coordinators to request the curtailment of transactions that are causing parallel flows through their system.
Transmission Owner	M14B, OATT	TO	A transmission owner is a PJM member that owns transmission facilities or leases with rights equivalent to ownership in transmission facilities. Taking transmission service is not sufficient to qualify a member as a transmission owner.
Transmission Owner Initiated		TOI	See “Supplemental Project.”
Transmission Owner Upgrade	OA		A transmission owner upgrade is an improvement to, addition to, or replacement of part of a transmission owner’s existing facility and is not an entirely new transmission facility.
Transmission Provider	M14B, OATT		The transmission provider is PJM for all purposes in accordance with the PJM OATT.
Transmission Service Request	M02	TSR	A transmission service request is a request submitted by a PJM market participant for transmission service over PJM-designated facilities. Typically, the request is for either short-term or long-term service, over a specific path for a specific megawatt amount. PJM evaluates each request and determines if it can be accommodated and, if the requestor so chooses, pursues needed upgrades to accommodate the request.
Transmission System	OATT		The transmission system comprises the transmission facilities operated by PJM used to provide transmission services. These facilities that transmit electricity: are within the PJM footprint; meet the definition of transmission facilities pursuant to FERC’s Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and have been demonstrated to the satisfaction of PJM to be integrated with the transmission system of PJM and integrated into the planning and operation of such to serve all of the power and transmission customers within such region.
Unforced Capacity	RAA	UCAP	Unforced capacity is an entitlement to a specified number of summer-rated MW of capacity from a specific resource, on average, not experiencing a forced outage or de-rating, for the purpose of satisfying capacity obligations imposed under the RAA.
Upgrade	OA		See “Transmission Owner Upgrade.”
Upgrade Construction Service Agreement		UCSA	The terms and conditions of a UCSA govern the construction activities associated with the upgrade of capability along an existing PJM bulk electric system circuit in order to accommodate a merchant transmission interconnection request. Facilities constructed under a UCSA are not owned by a developer. All ownership rights of the physical facilities are retained by the respective transmission owner following the completion of construction. PJM and the developer execute a separate UCSA with each impacted transmission owner. A developer retains the right, but not the obligation (option to build), to design, procure, construct and install all or any portion of the direct assignment facilities and/or customer-funded upgrades.
Violation	M14B		A violation is a PJM planning study result that shows a specific system condition that is not in compliance with established NERC, ReliabilityFirst, SERC or PJM reliability criteria.
Weather Normalized Peak	M19		The weather normalized peak is an estimate of the seasonal peak load at normal peak-day weather conditions.
Western Subregion	M14B, OA		The PJM Western Subregion comprises five transmission owner zones: Allegheny Power (AP), American Electric Power (AEP), American Transmission Systems Incorporated (ATSI), Commonwealth Edison Co. (ComEd), Dayton Power & Light Co. (DAY), Duke Energy Corporation (DEO&K), Duquesne Light Company (DLCO) and East Kentucky Power Cooperative (EKPC).
Wheel			A wheel is the contracted, third-party use of electrical facilities to transmit power whose origin and destination are outside the entity transmitting the power.
Wholesale Market Participation Agreement	M14C	WMPA	A contractual agreement required for generators planning to connect to the local distribution systems at locations that are not under FERC jurisdiction and wish to participate in PJM’s market.
X-Effective Forced Outage Rate on Demand		XEFORd	XEFORd is a statistic that results from excluding events outside management control (outages deemed not to be preventable by the operator) from the EFORd calculation. See “Effective Forced Outage Rate on Demand (EFORd).”
Zone/Control Zone	M14B		A zone/control zone is an area within the PJM control area, as set forth in the PJM OATT and the Reliability Assurance Agreement (RAA). Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.

Key Maps, Tables and Figures

PJM | DE | DC | IL | IN | KY | MD | MI | NJ | NC | OH | PA | TN | VA | WV

Map 1.1: PJM Backbone Transmission System

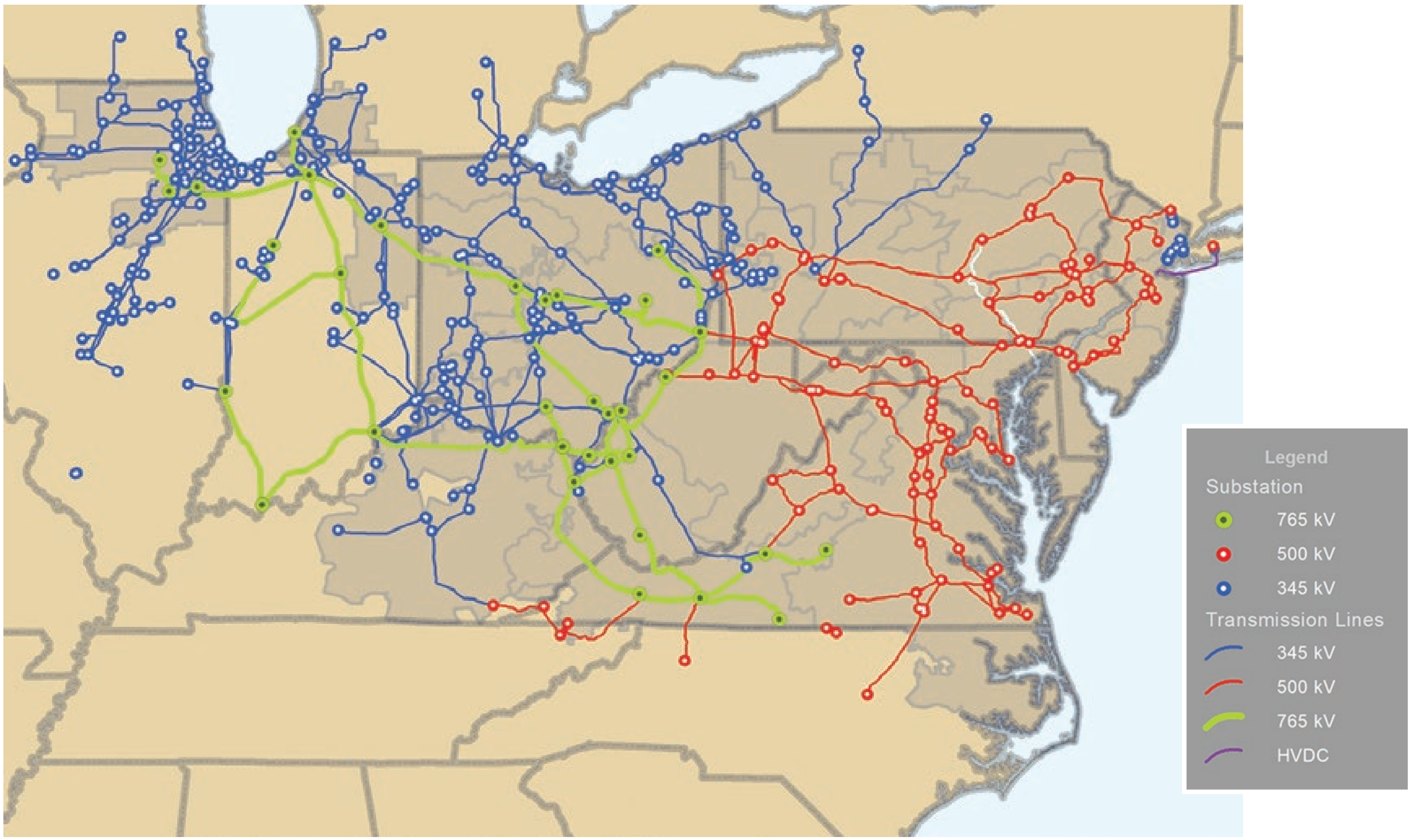


Figure 1.1: RTEP Process – RTO Perspective

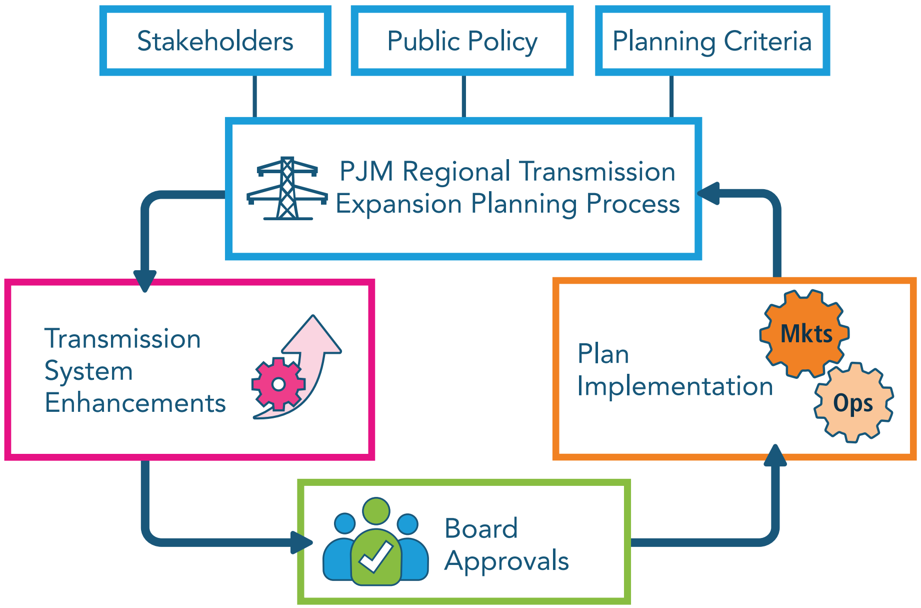


Figure 1.2: System Enhancement Drivers

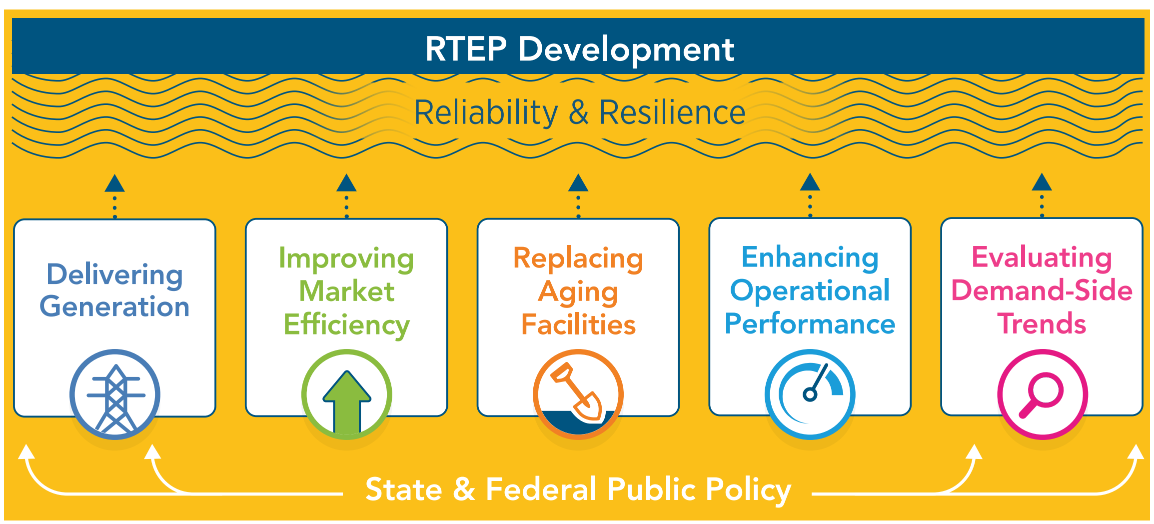


Figure 1.3: Board Approved RTEP Projects as of Dec. 31, 2020

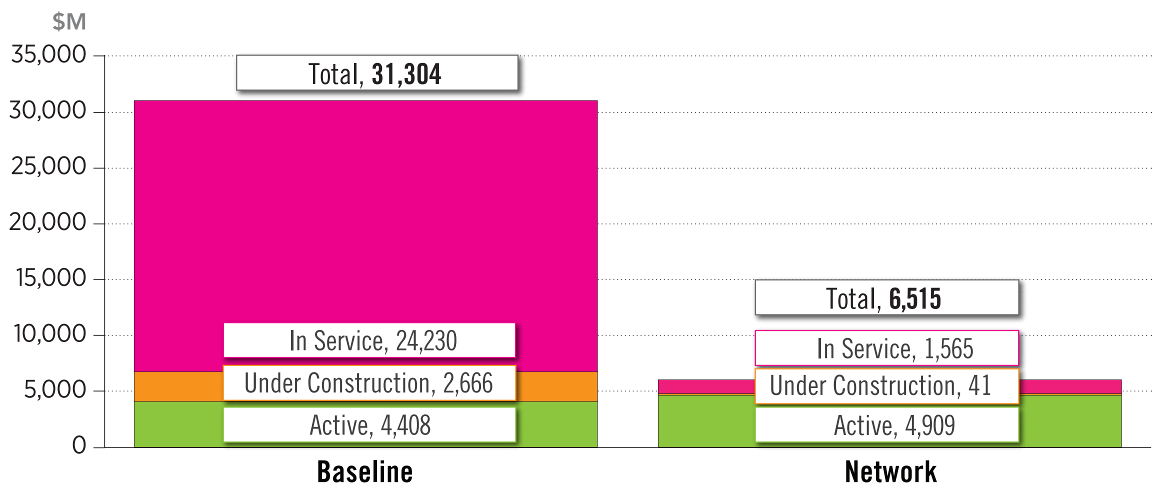
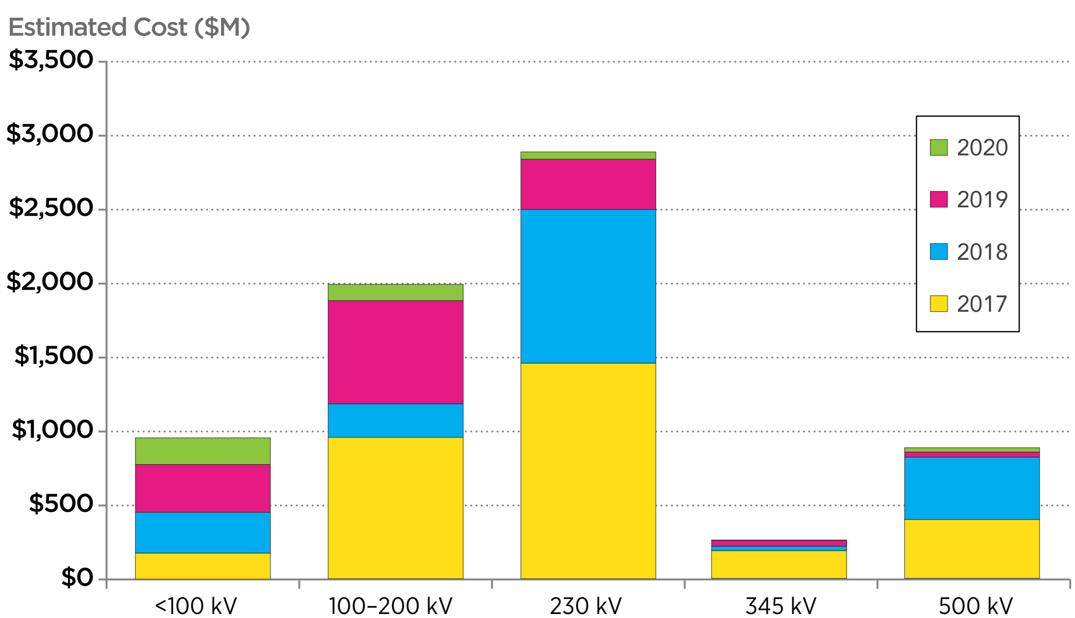


Figure 1.4: Approved Baseline Projects by Voltage 2017-2020



No baseline projects at the 765 kV level were identified for this time period.

Figure 1.5: PJM Existing RPM-Eligible Installed Capacity Mix (Dec. 31, 2020)

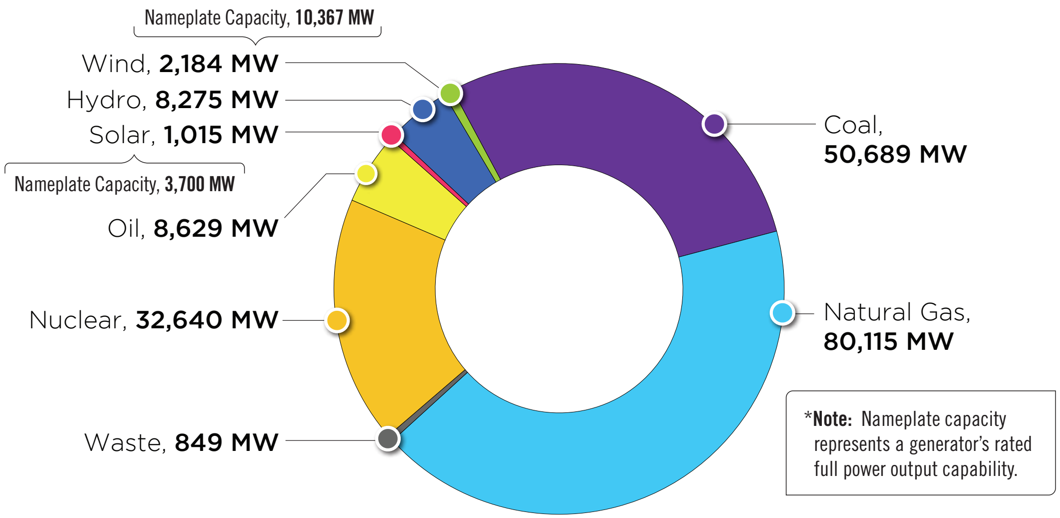


Figure 1.6: Queued Generation Fuel Mix – Requested Capacity Interconnection Rights (Dec. 31, 2020)

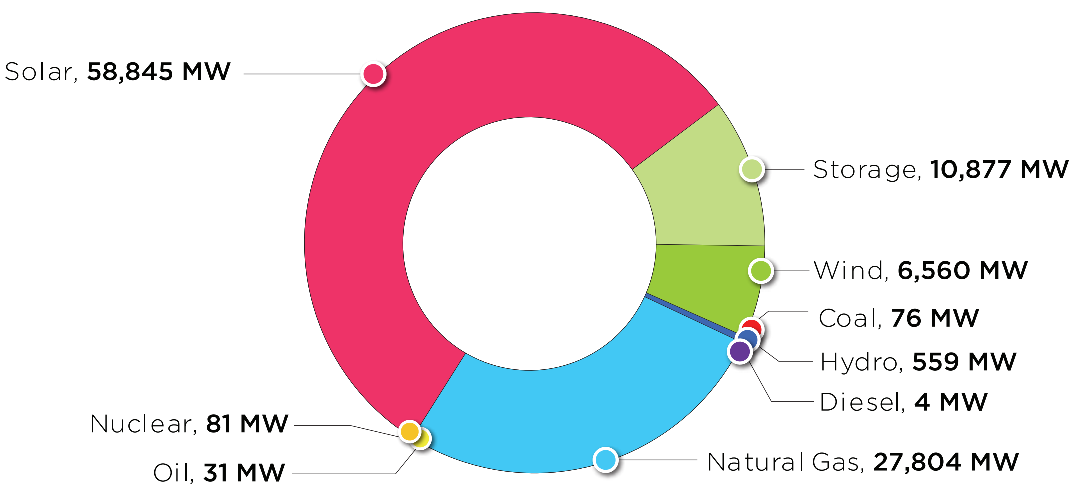


Figure 1.8: Growth of Renewables in PJM Queue

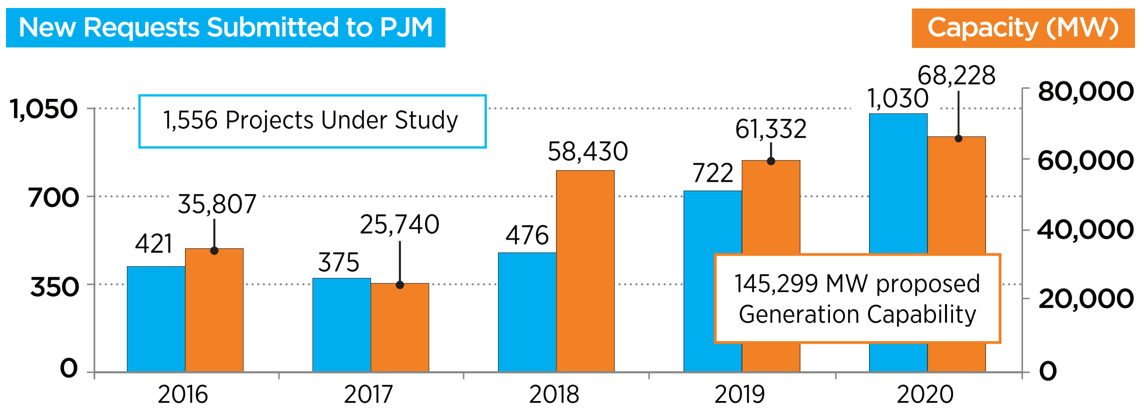
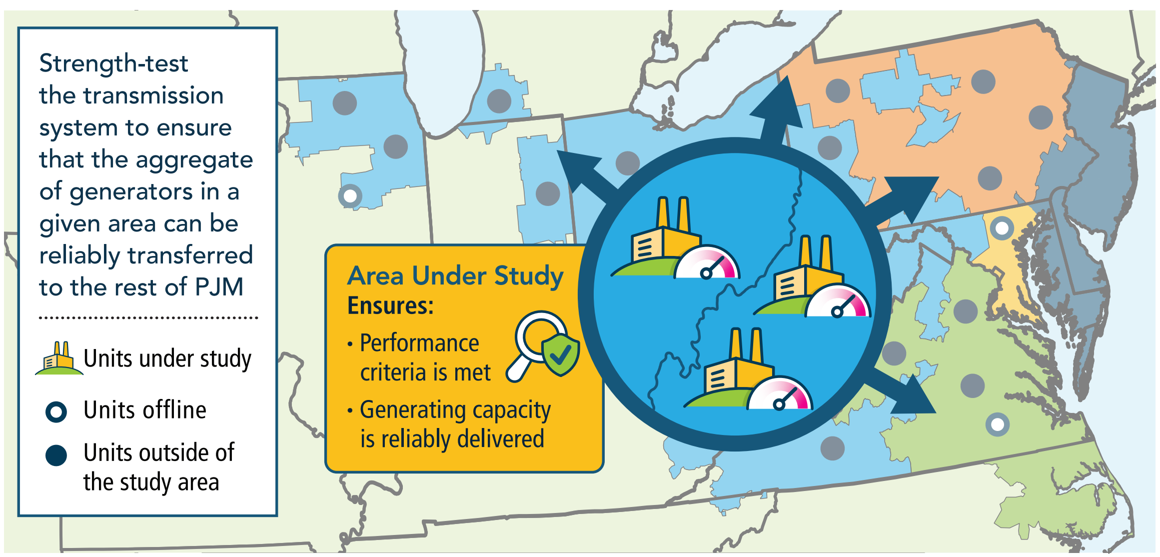


Figure 1.7: Generator Deliverability Concept



Map 1.2: PJM Generator Deactivation Notifications Received Jan 1, 2020 through Dec. 31, 2020)

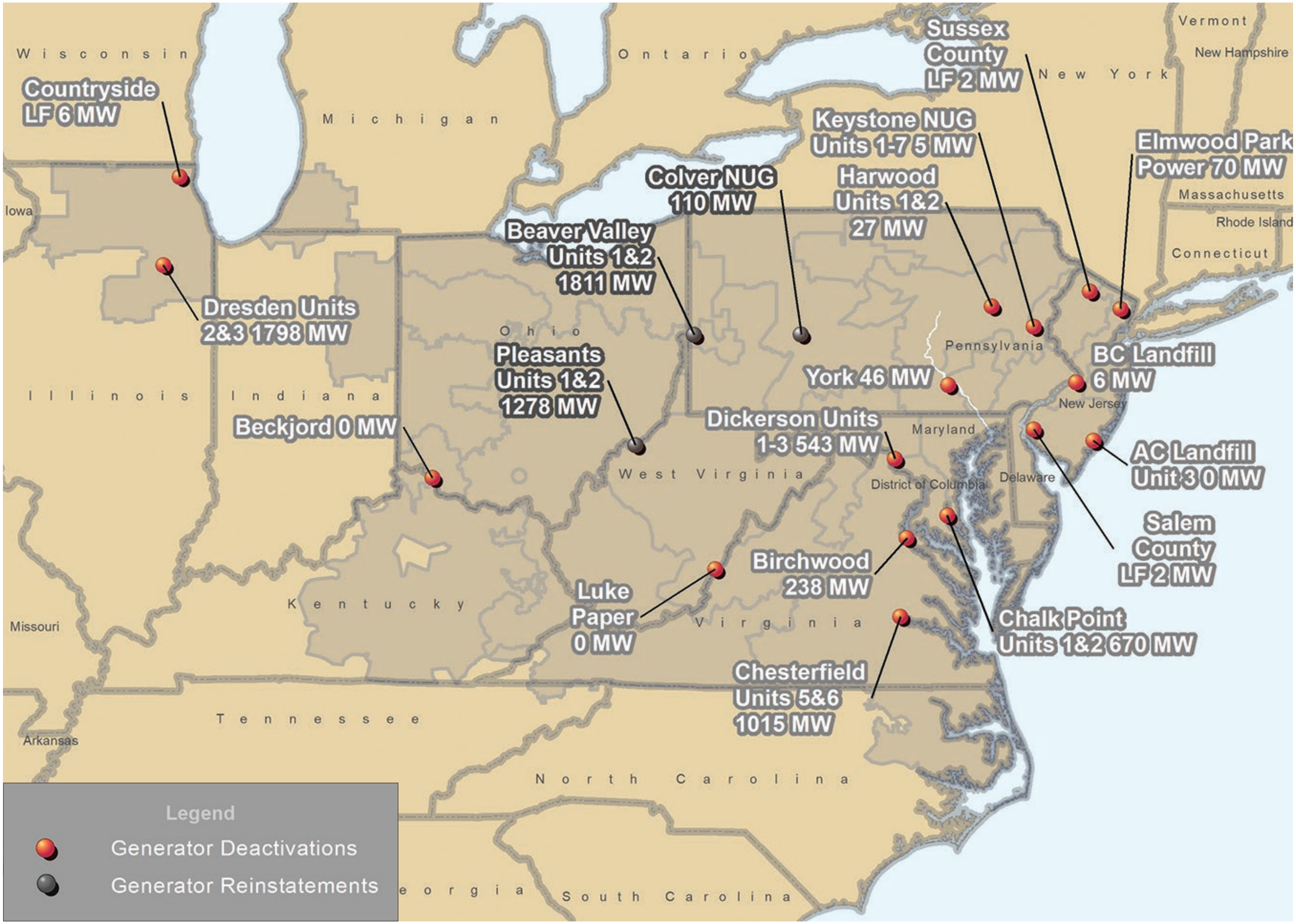
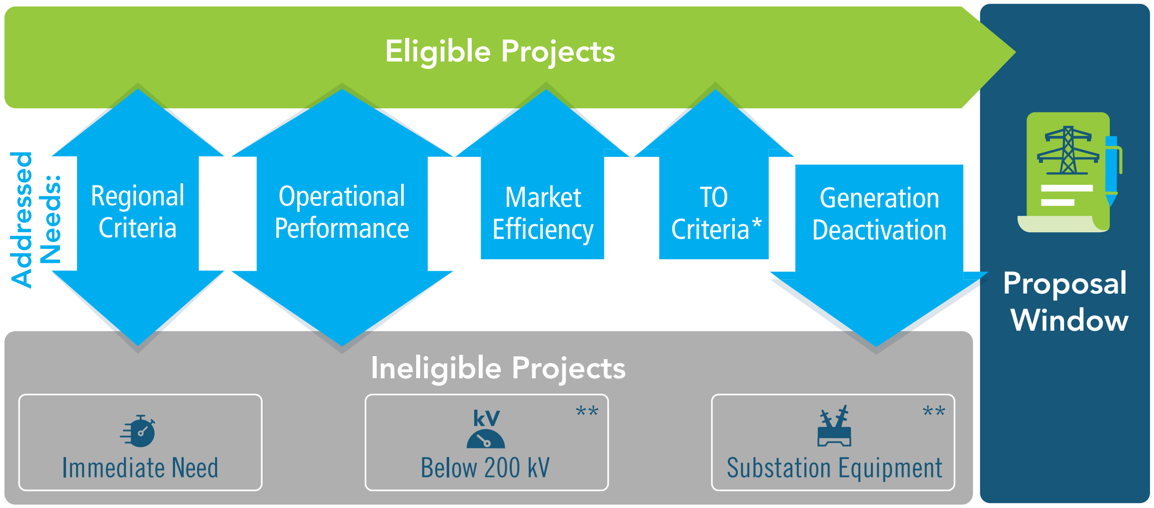


Figure 1.9: RTEP Proposal Window Eligibility



Note: **TO Criteria is eligible for proposal windows as of Jan. 1, 2020.*
***Projects below 200 kV and substation equipment projects could become eligible for competition if multiple needs share common geography/contingency or if the project has multi-zonal cost allocation.*

Figure 1.10: 2020 RTEP Baseline Project Driver ($ Million)

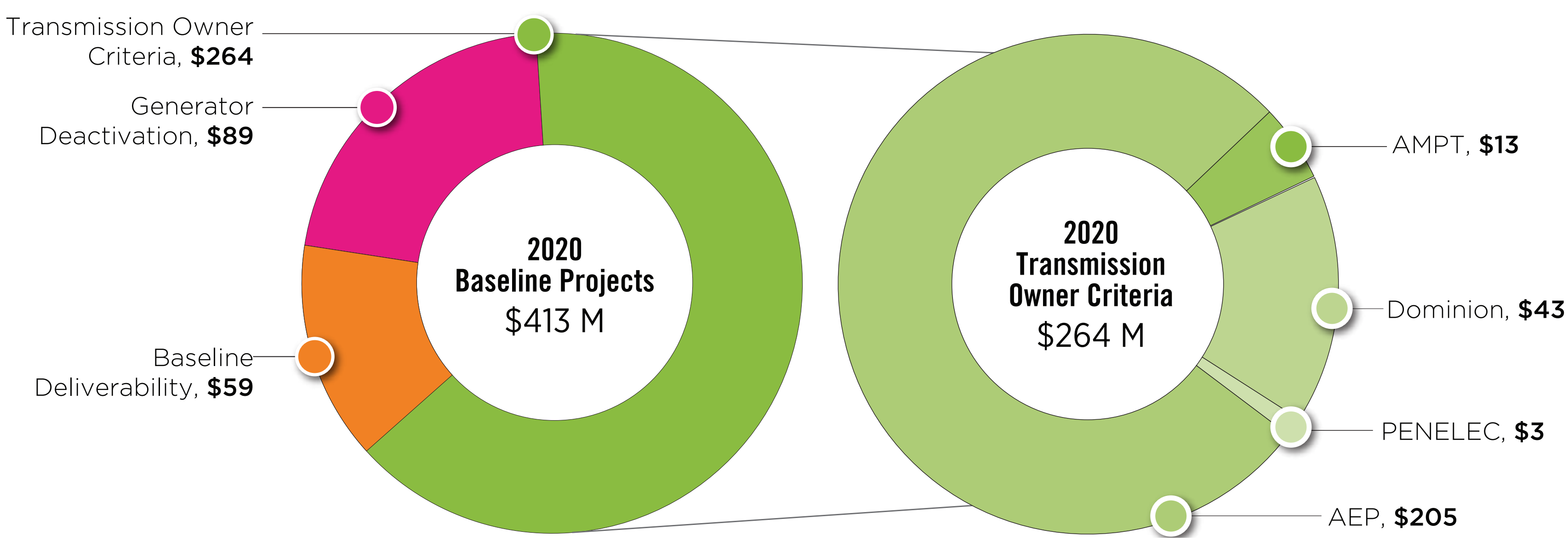


Figure 1.11: Load Forecast Model

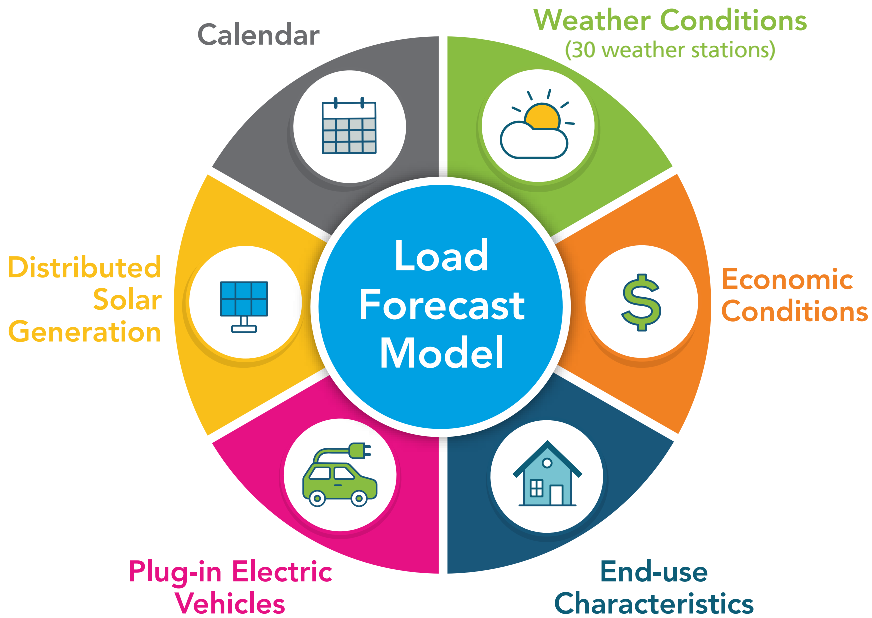
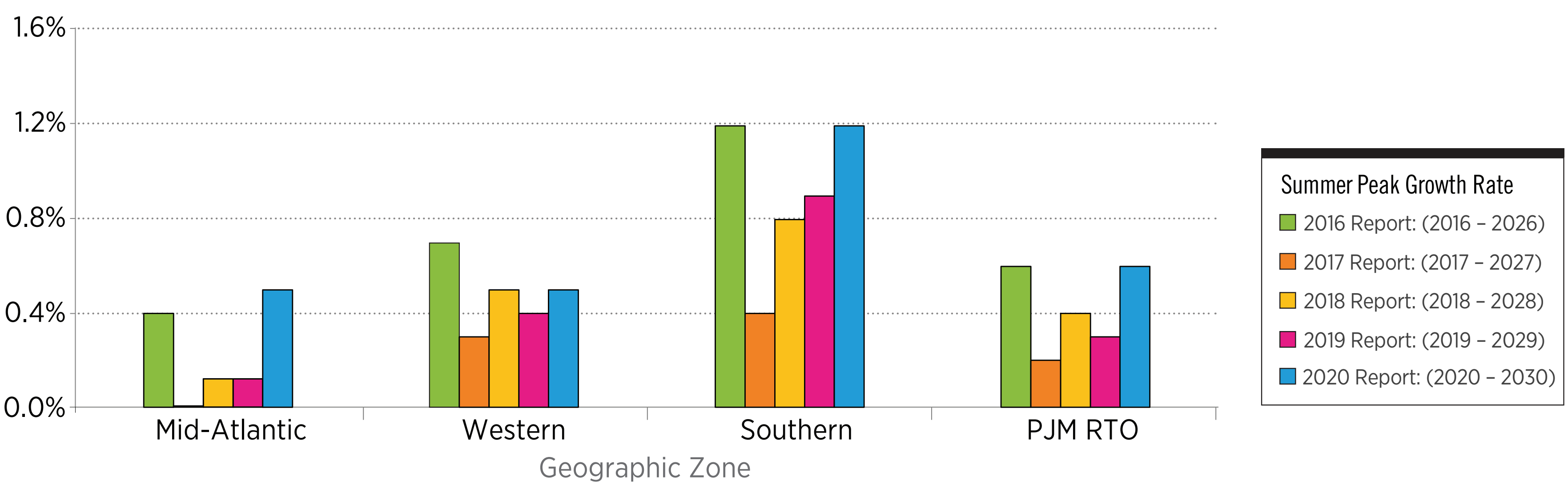


Figure 1.12: PJM 10-Year Summer Peak Load Growth Rate Comparison 2016-2020 Load Forecast Reports



Map 1.3: 2020 RTEP Baseline Thermal and Voltage Criteria Violations

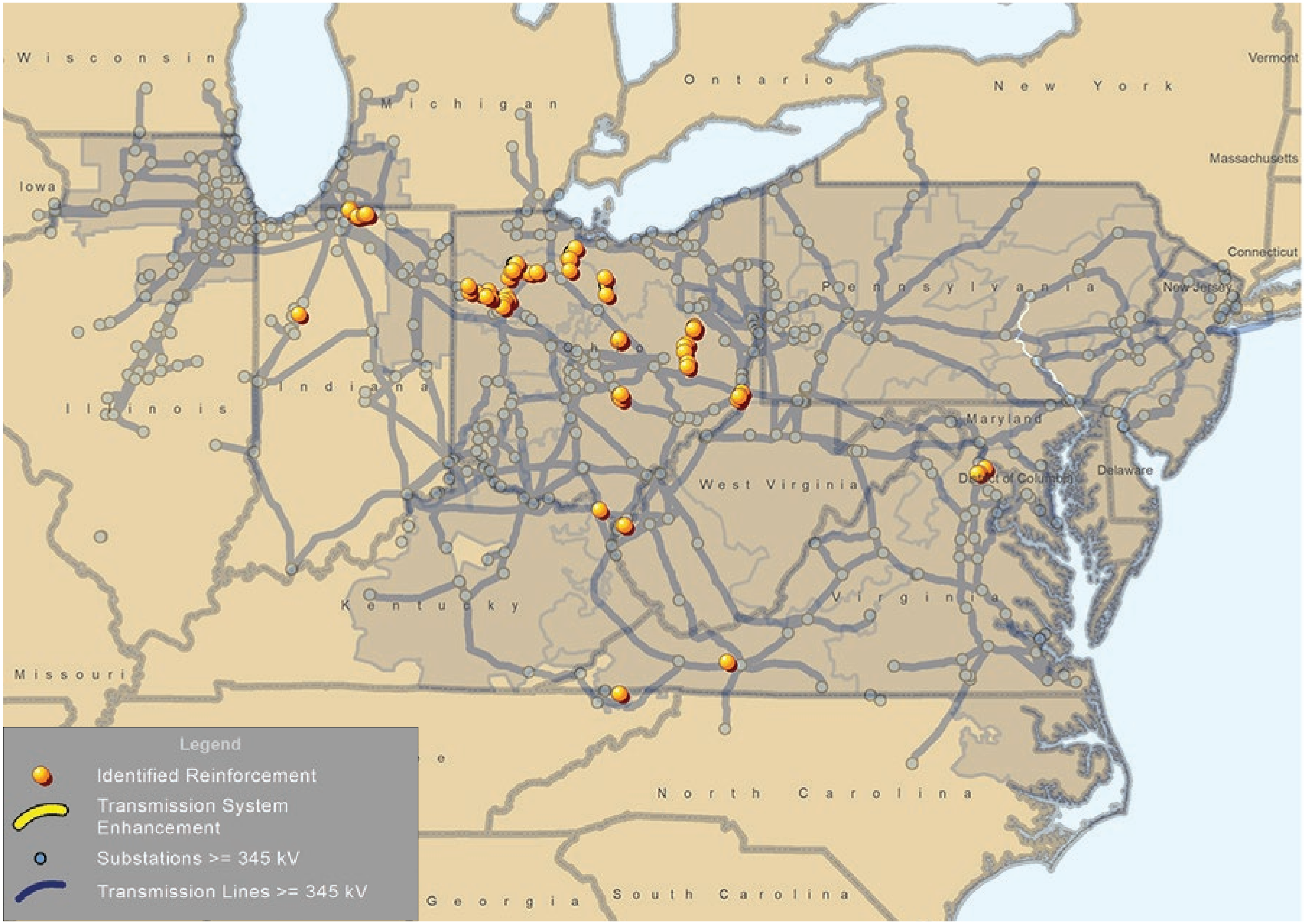


Figure 1.13: Primary Supplemental Project Drivers

Customer Service	Provide service to new and existing customers; interconnect new customer load; address distribution load growth, customer outage exposure, equipment loading, etc.
Equipment Material Condition, Performance and Risk	Address degraded equipment performance, material condition, obsolescence; end of the useful life of equipment or a facility; equipment failure; employee and public safety; environmental impact.
Operational Flexibility and Efficiency	Optimize system configuration, equipment duty cycles and restoration capability; minimize outages.
Infrastructure Resilience	Improve system ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event, including severe weather or geomagnetic disturbances.
Other	Meet objectives not included in other definitions such as, but not limited to, technological pilots, industry recommendations, environmental and safety impacts, etc.

Figure 1.14: Attachment M-3 Process for Supplemental Projects

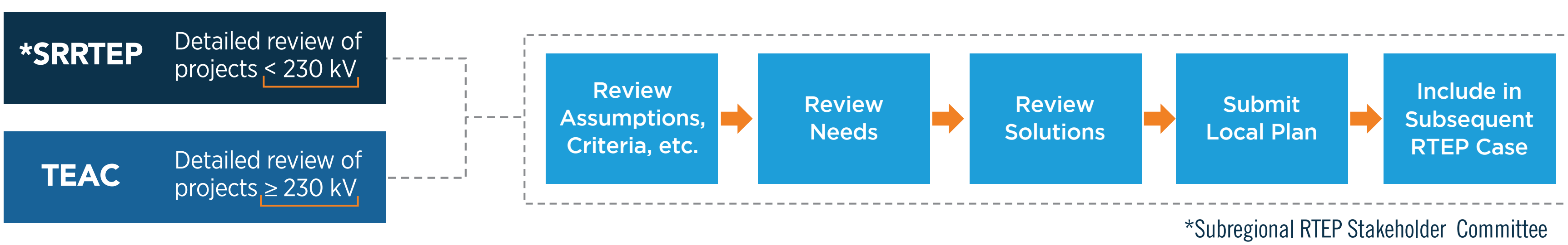


Figure 1.15: 2020/2021 Market Efficiency 24-Month Cycle

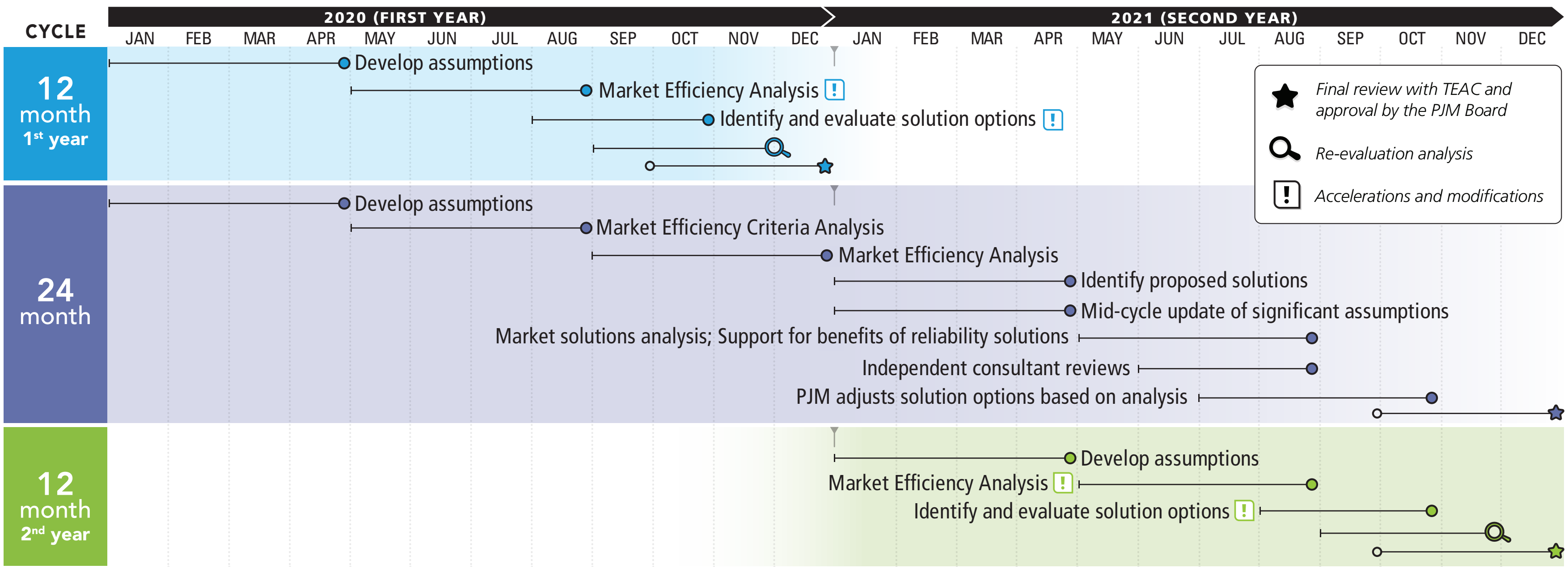
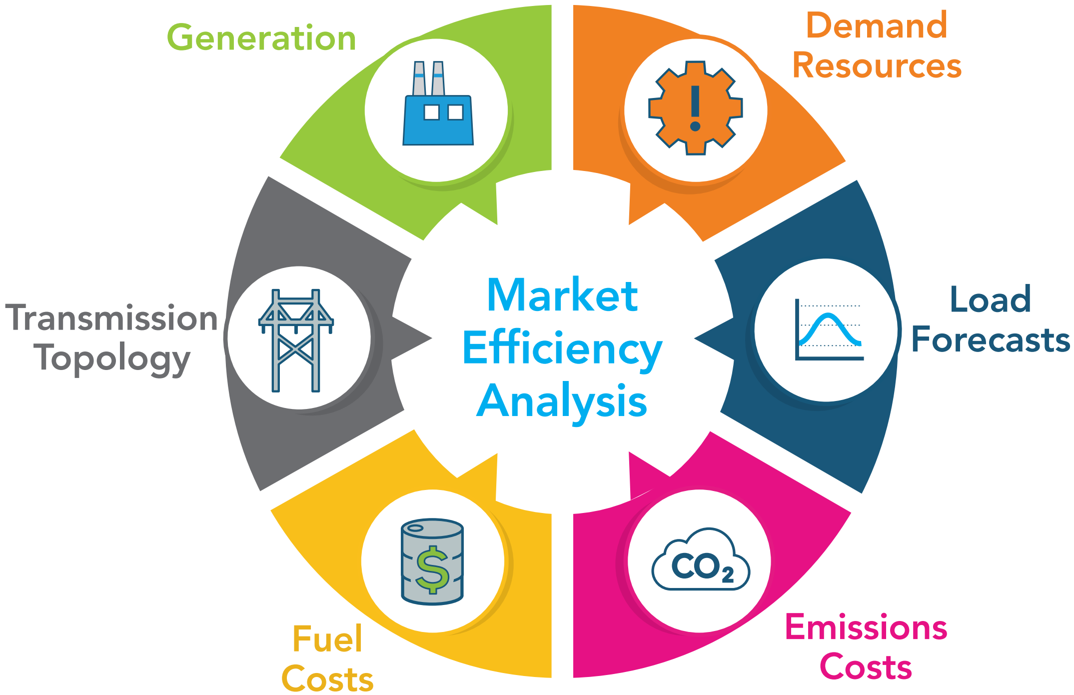
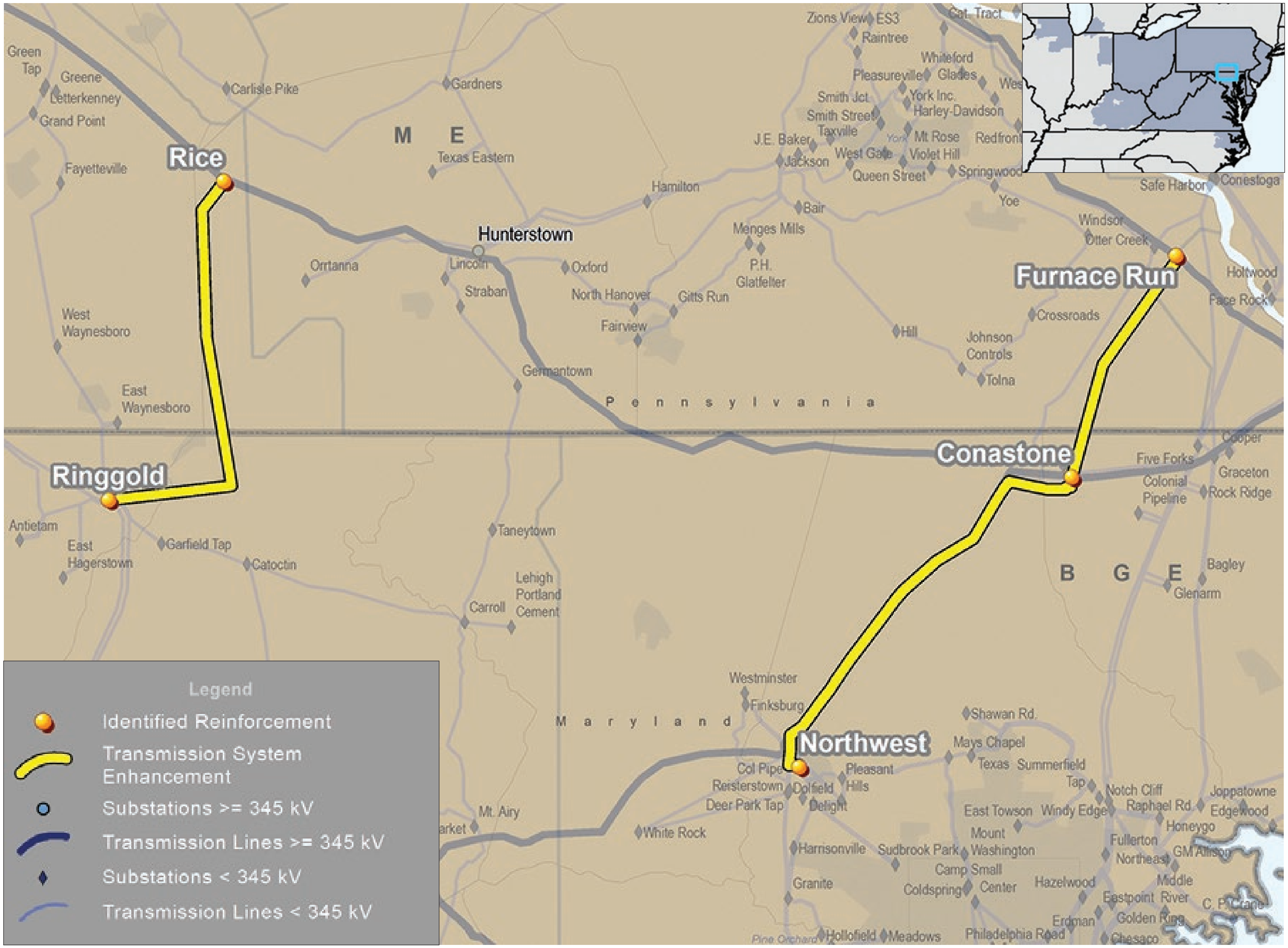


Figure 1.16: Market Efficiency Analysis Parameters



Map 1.4: Project 9A – RTEP Baseline Projects B2743 and B2752



Map 1.5: Feasibility and System Impact Studies Performed in 2020

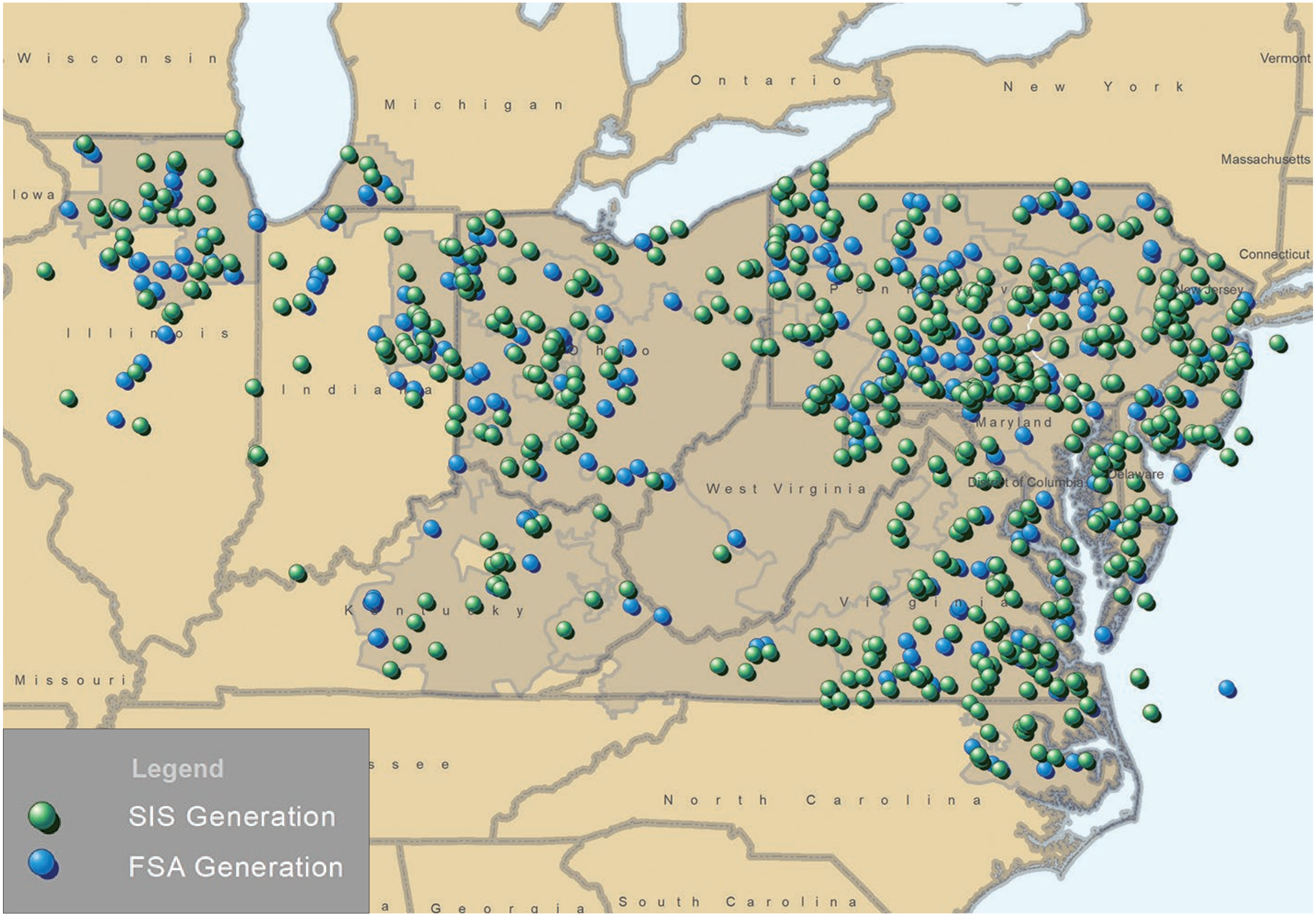
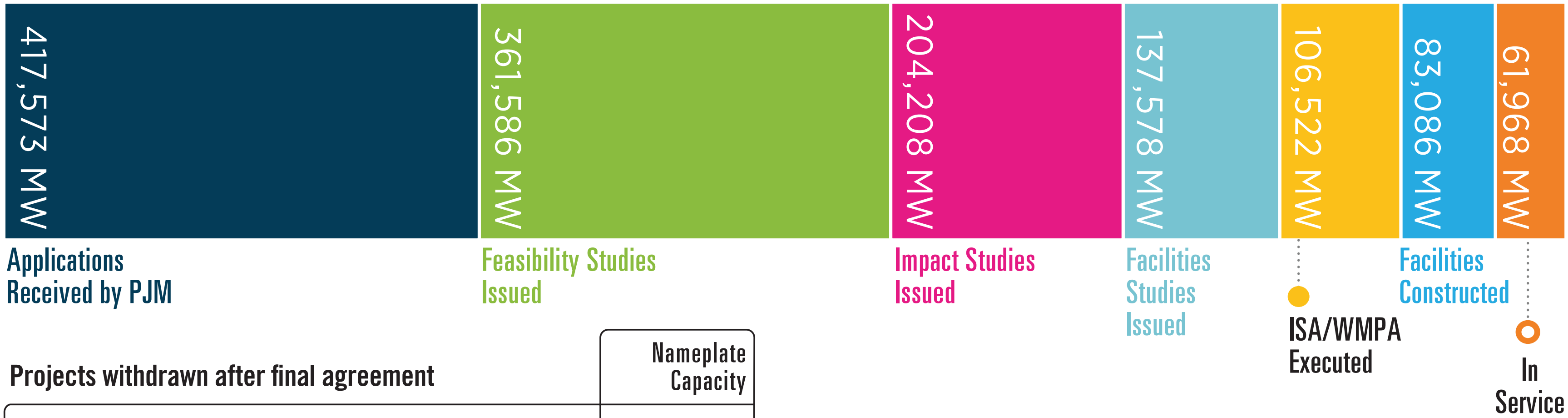


Figure 1.17: Queued Generation Progression – Requested Capacity Rights (Dec. 31, 2020)



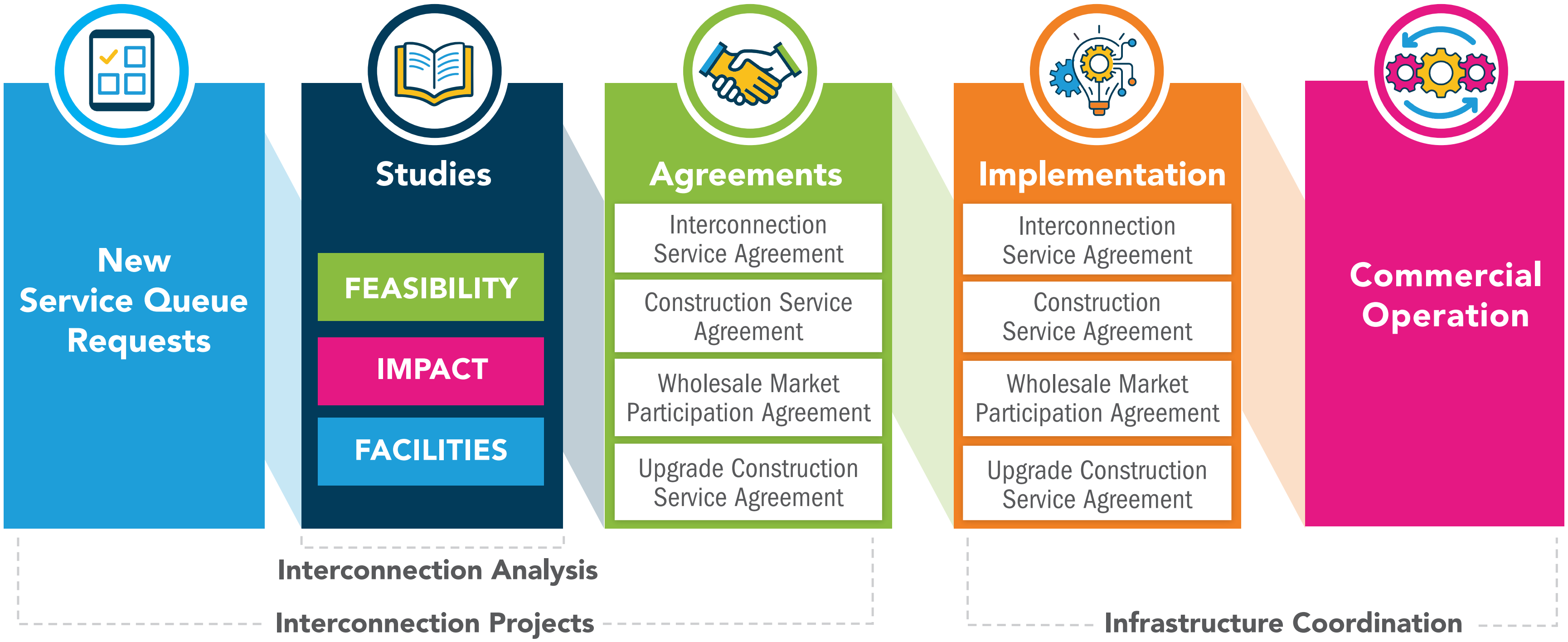
Projects withdrawn after final agreement

			Nameplate Capacity
177	Interconnection Service Agreements	**22,442** MW	30,294 MW
291	Wholesale Market Participation Agreements	**1,107** MW	2,293 MW

Percentage of planned capacity and projects that have reached commercial operation	**15%** Requested capacity megawatts	**23%** Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2020.

Figure 1.18: New Services Queue Process Overview



Appendix 5: RTEP Project Statistics

PJM | DE | DC | IL | IN | KY | MD | MI | NJ | NC | OH | PA | TN | VA | WV

5.0: RTEP Project Statistics

This set of figures and tables summarize the estimated costs for projects presented at the Transmission Expansion Advisory Committee or Subregional TEAC meetings. It is intended to provide a visual representation and consolidate materials presented elsewhere in this report to allow stakeholders to view trends in the identification of violations over time, and by voltage class. Where historical costs are used in the comparison of a graph, the costs have been adjusted for inflation to have a common representation of 2020 dollars, as discussed below.

1. Baseline project was approved by the PJM Board.
2. Supplemental project was presented at the TEAC or Subregional TEAC meetings.
3. Costs are provided by the designated entity or transmission owners. Cost estimation methods may vary by company. Estimated costs in this document may include cost caps or cost containment, even though it isn't specifically noted.
4. Cost estimates may change over time as new information is incorporated into the estimate by the project sponsor. This document reflects the current estimates that are provided to PJM.
5. Estimated project costs are adjusted by average inflation rate from 2010 to 2019 (1.77%).
6. Transmission line mileage is based on FERC Form 1 filed in 2019 or EIA-411 Schedule 6A for 2019.
7. TO peak load is the average of forecasted summer peak load from 2021 to 2025.

Figure 5.1: Project Status as of Dec., 31 2020

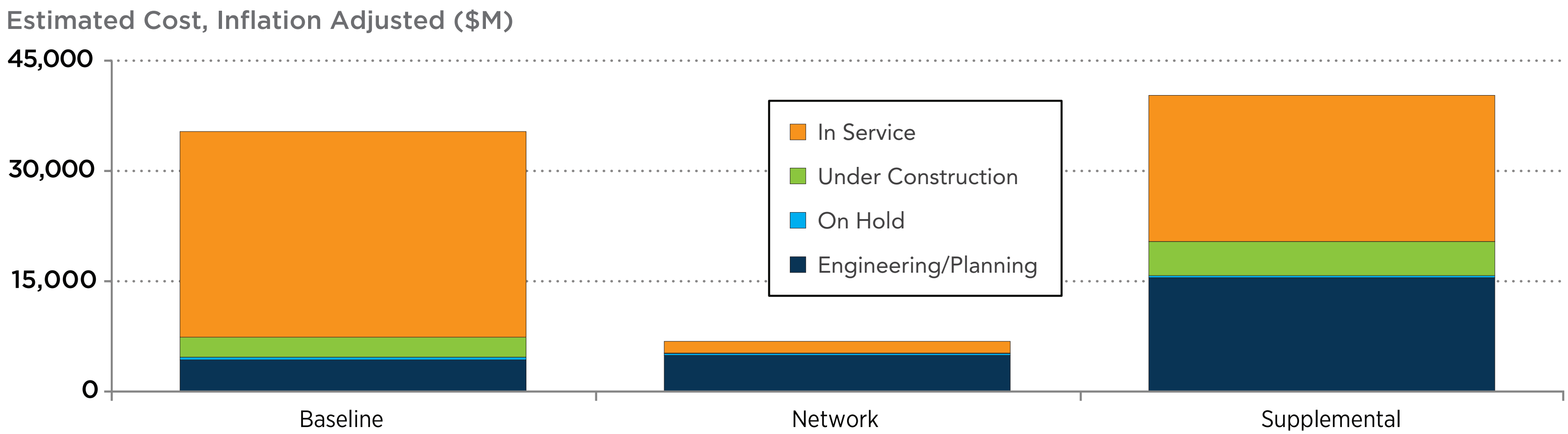


Figure 5.2: Baseline and Supplemental Projects by Year

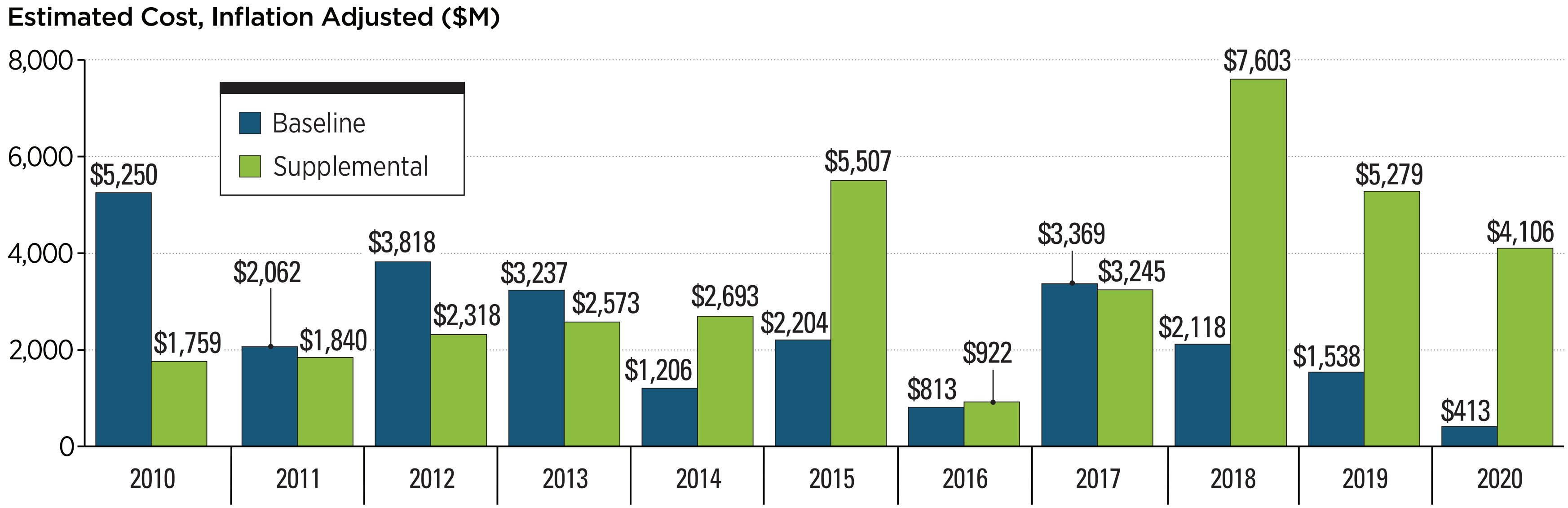


Figure 5.3: PJM Baseline Projects by Criteria

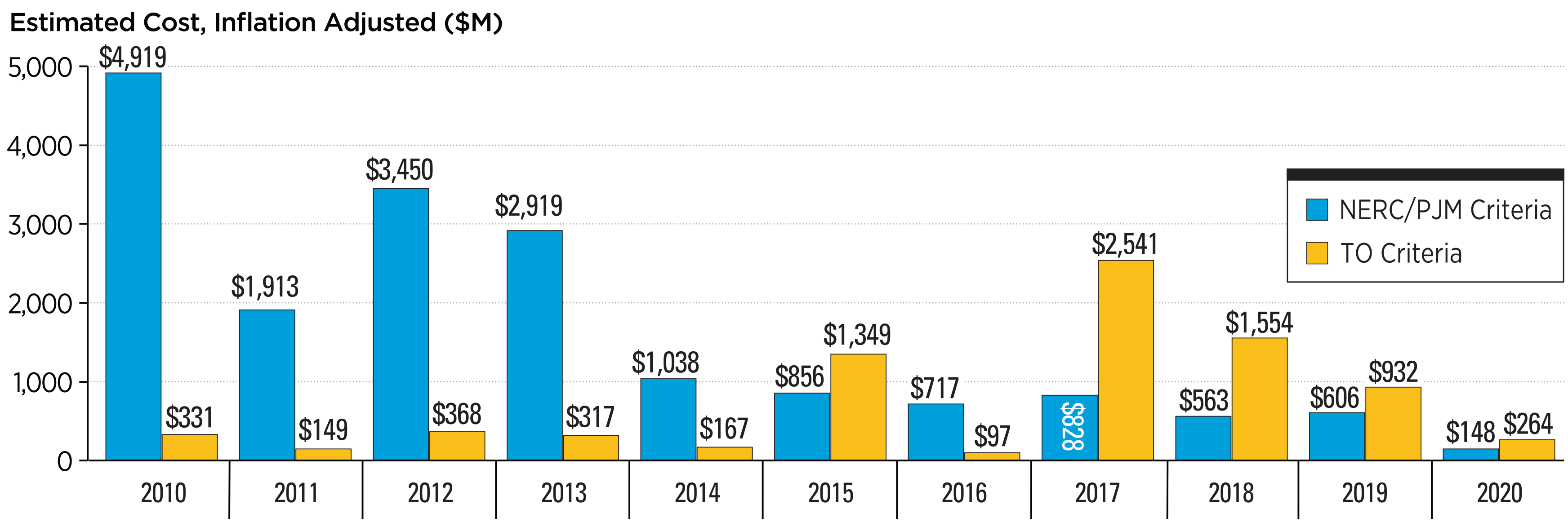


Figure 5.4: Baseline Projects by Voltage

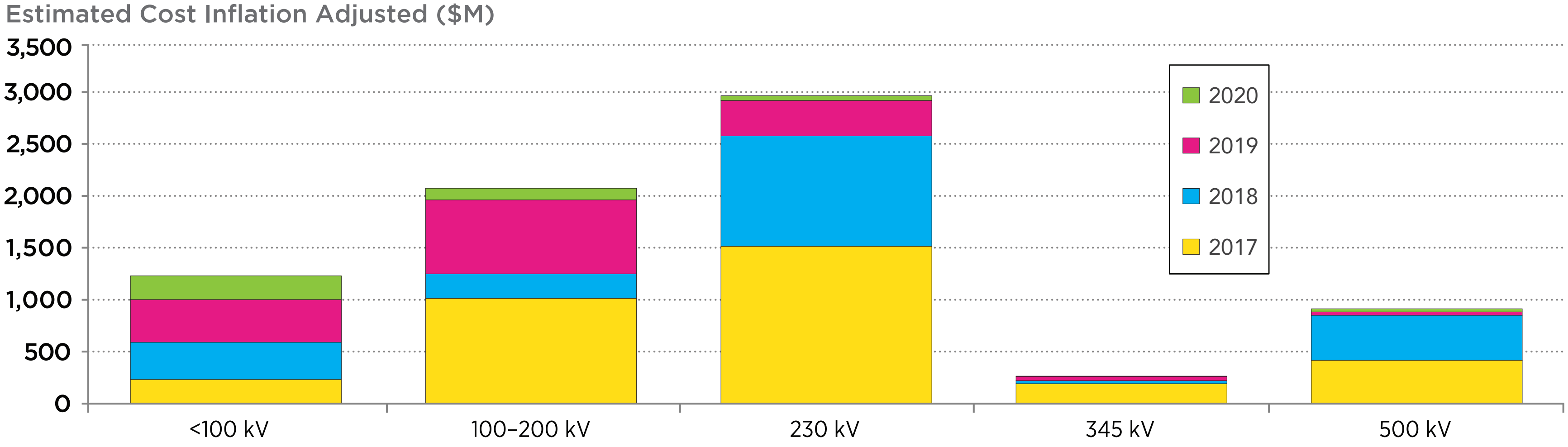


Figure 5.5: Supplemental Projects by Voltage

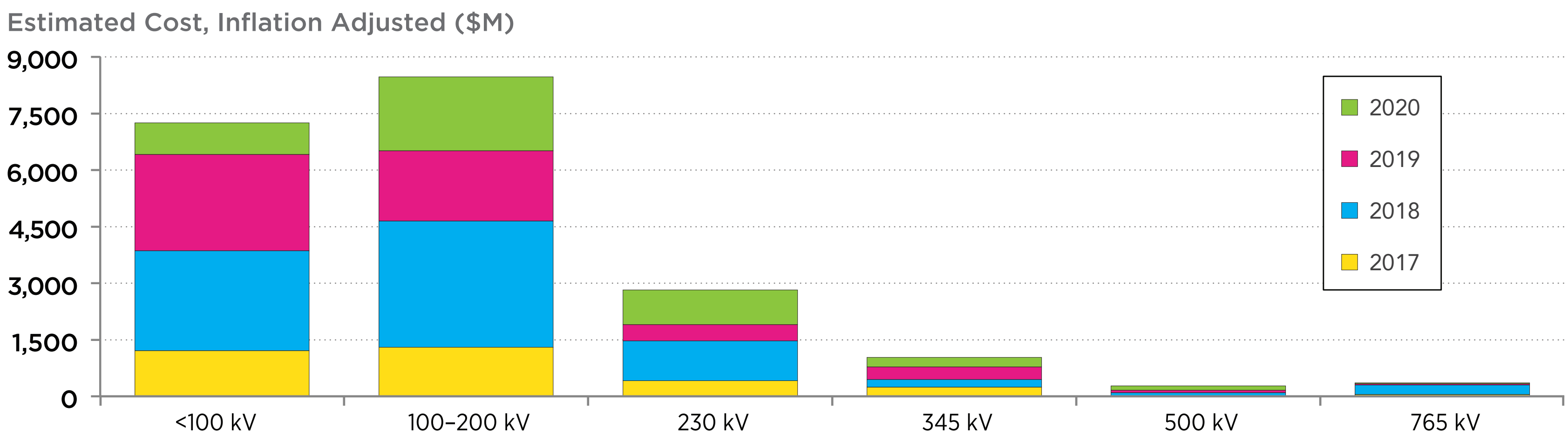


Figure 5.6: Baseline and Supplemental Projects by Designated Entity Since 2010

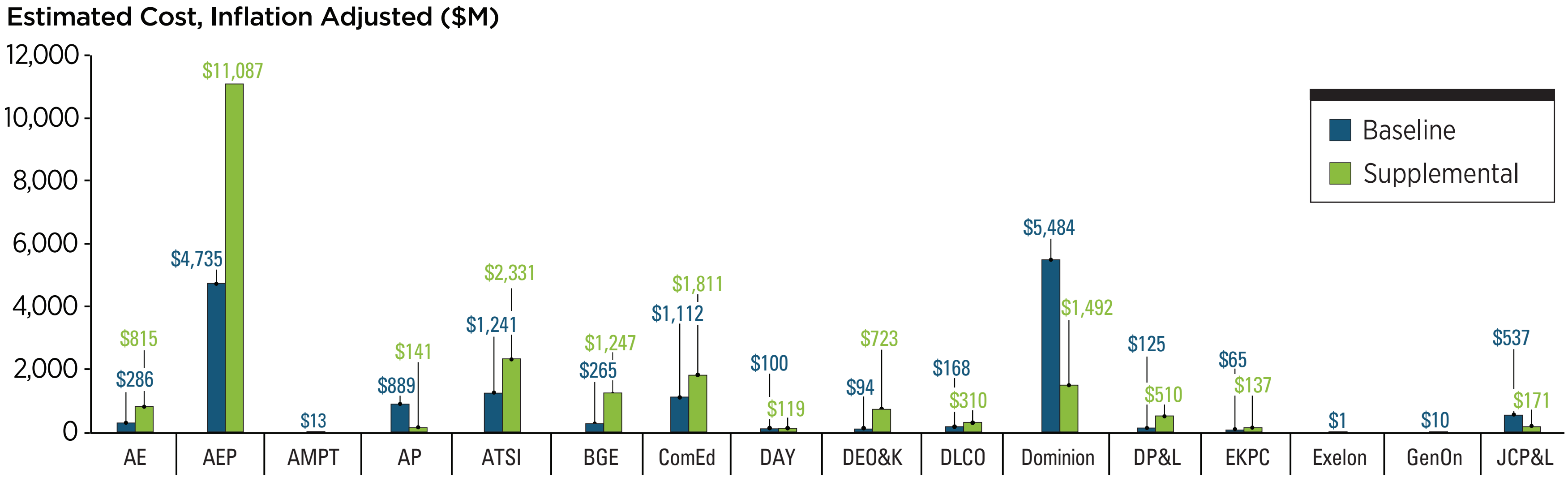


Figure 5.6: Baseline and Supplemental Projects by Designated Entity Since 2010 (Cont.)

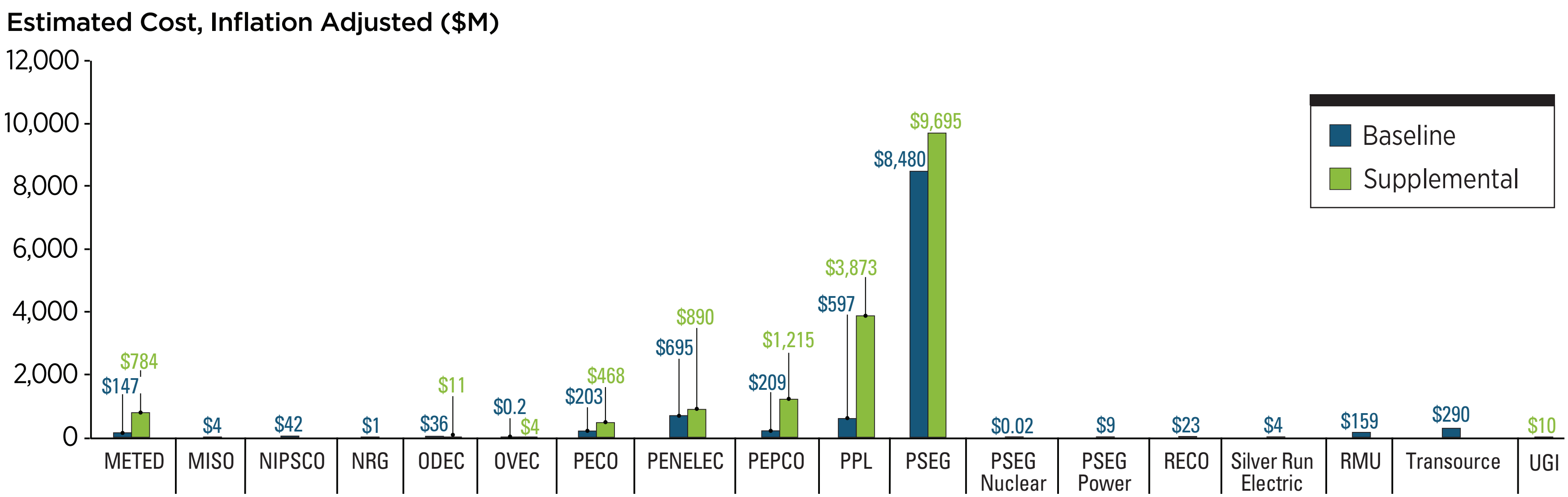


Figure 5.7: 2020 Baseline and Supplemental Projects by Designated Entity

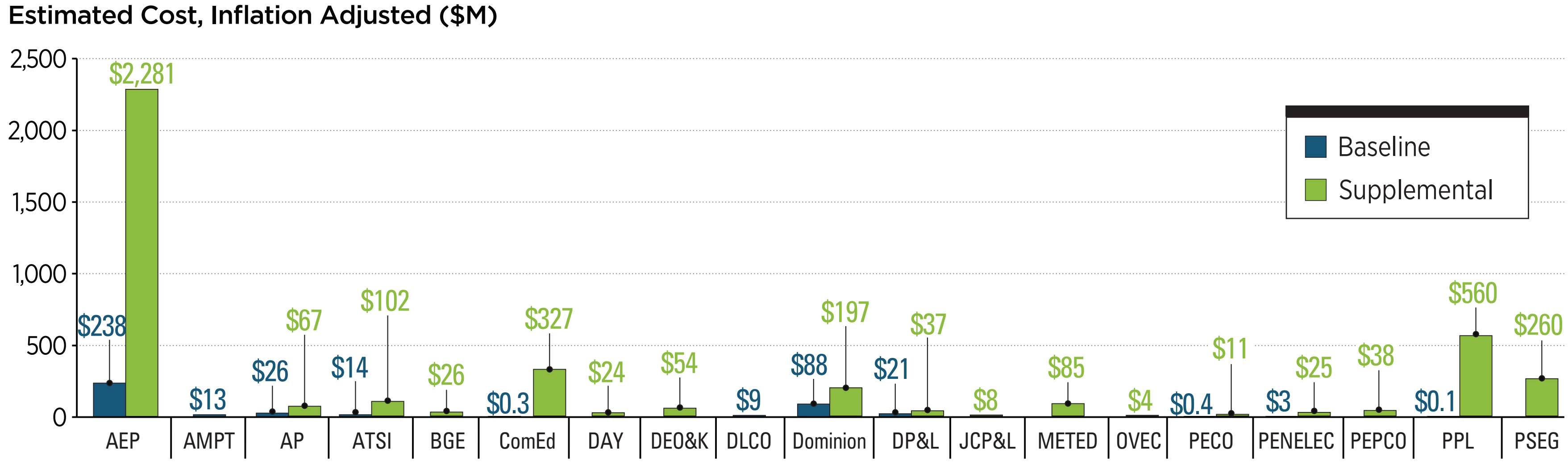


Figure 5.8: Baseline and Supplemental Projects adjusted by Peak Load Since 2010

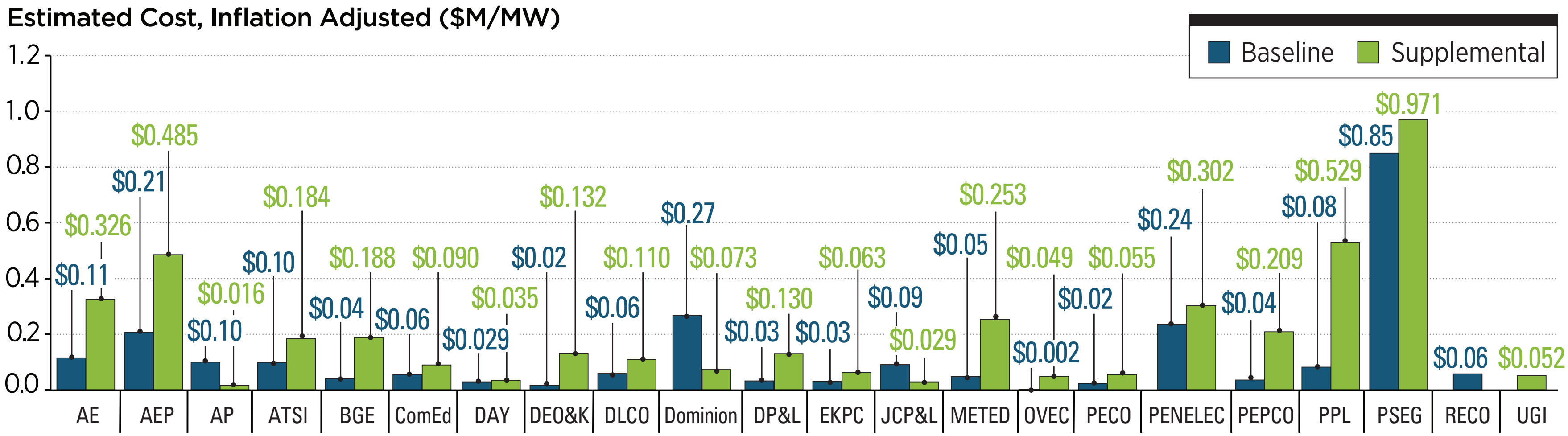


Figure 5.9: 2020 Baseline and Supplemental Projects Adjusted by Peak Load

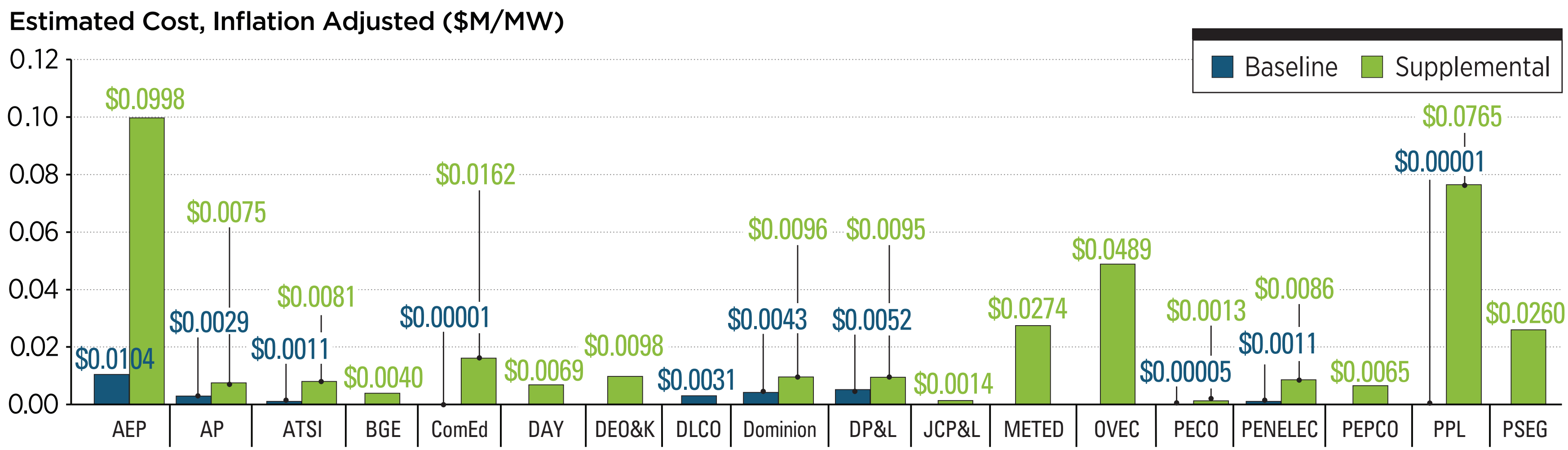


Figure 5.10: Baseline and Supplemental Projects Adjusted by Circuit Miles Since 2010

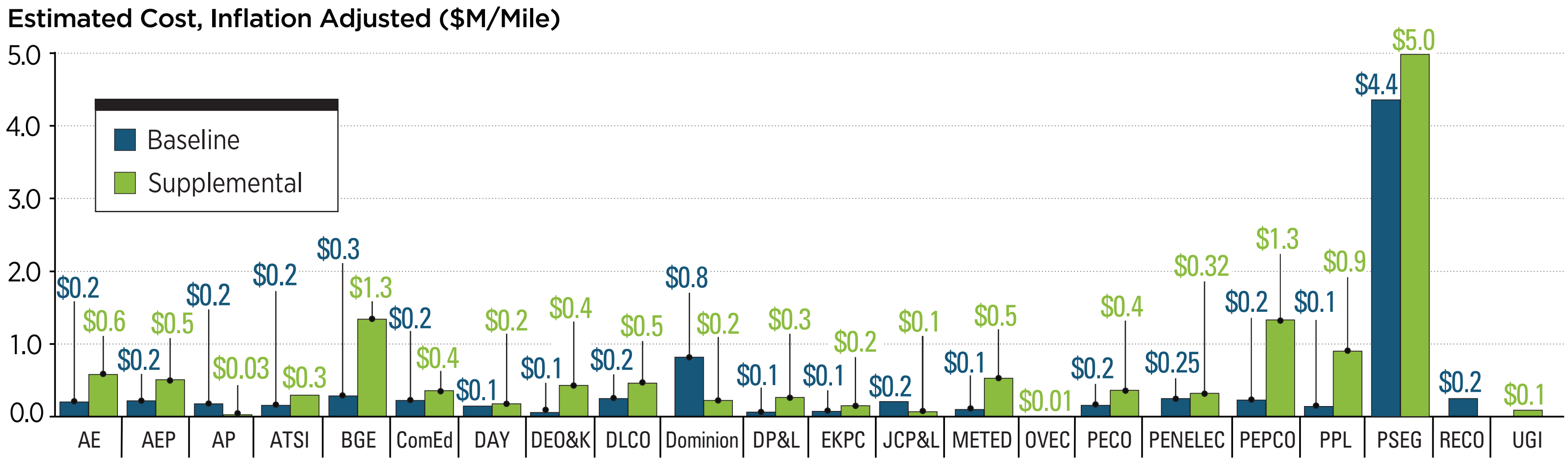
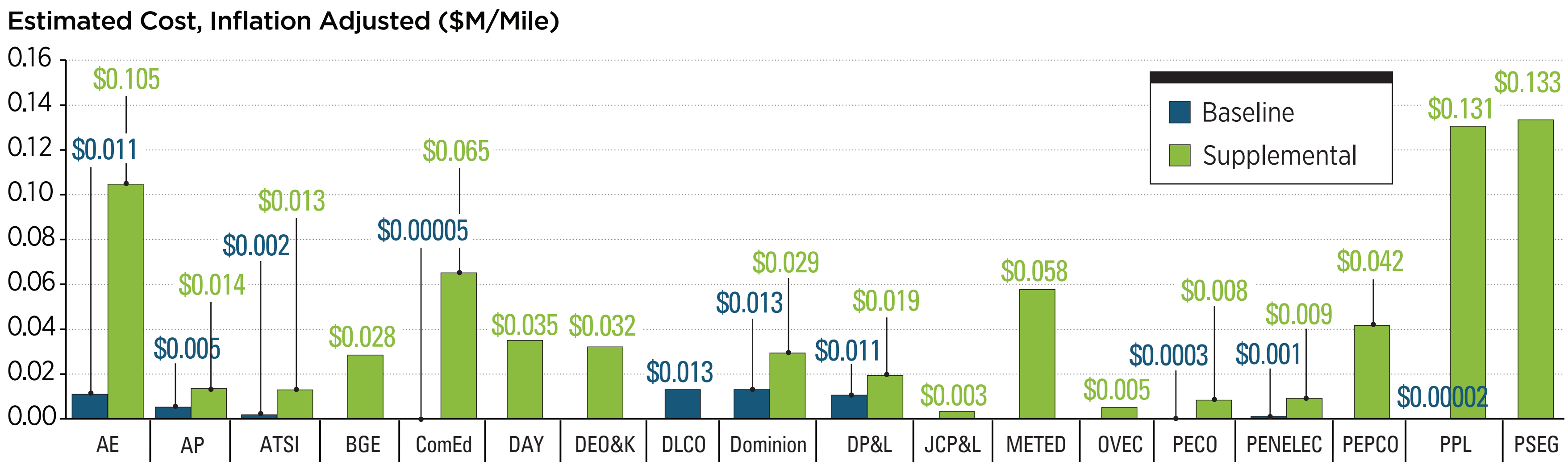


Figure 5.11: 2020 Baseline and Supplemental Projects Adjusted by Circuit Miles



BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF:	)	
	)	ORDER RESPONDING TO
UNITED STATES STEEL	)	PETITIONER'S
CORPORATION – GRANITE CITY	)	REQUEST THAT THE
WORKS	)	ADMINISTRATOR
	)	OBJECT TO ISSUANCE OF STATE
CAAPP No. 96030056	)	OPERATING PERMIT
Proposed by the Illinois	)	
Environmental Protection Agency	)	Petition Number V-2009-03
	)	

ORDER GRANTING IN PART AND DENYING IN PART PETITION FOR OBJECTION TO PERMIT

INTRODUCTION

On September 3, 2009, pursuant to its authority under the Illinois Clean Air Act Permitting Program (CAAPP), the Illinois Environmental Protection Act, 415 ILCS 5/39.5, title V of the Clean Air Act (Act), 42 U.S.C. §§ 7661-7661f, and the United States Environmental Protection Agency's (EPA) implementing regulations in 40 C.F.R. part 70 (part 70), the Illinois Environmental Protection Agency (IEPA) issued a title V operating permit to United States Steel Corporation – Granite City Works (USS). USS is an integrated steel manufacturing facility that involves raw material processing/preparation, coke production, coke oven gas by-products recovery plant, iron production, steel production, and steel finishing.

On October 1, 2009, the Interdisciplinary Environmental Clinic at the Washington University School of Law submitted to EPA on behalf of the American Bottom Conservancy (Petitioner) a petition requesting that EPA object to the USS title V permit pursuant to section 505(b)(2) of the Act, 42 U.S.C. § 7661d(b)(2), and 40 C.F.R. § 70.8(d). Petitioner alleges that (1) the permit fails to include all applicable permits and permit requirements; (2) the permit fails to provide periodic monitoring sufficient to assure compliance; (3) the permit lacks compliance schedules to remedy all current violations; (4) the permit unlawfully exempts emissions during startup, shutdown, and malfunctions (SSM); (5) the permit fails to include compliance assurance monitoring (CAM) requirements; and (6) numerous permit provisions are not practically enforceable.

EPA has reviewed Petitioner's allegations pursuant to the standard set forth in section 505(b)(2) of the Act, 42 U.S.C. § 7661d(b)(2), which requires the Administrator to issue an objection if the petitioner demonstrates to the Administrator that the permit is not in compliance with the applicable requirements of the Act. *See also* 40 C.F.R. § 70.8(d); *New York Public Interest Research Group* v. *Whitman,* 321 F.3d 316, 333, n. 11 (2d Cir. 2003).

Based on a review of the available information, including the petition, the permit record, and relevant statutory and regulatory authorities and guidance, I grant Petitioner's request in part and deny it in part, for the reasons set forth in this Order.

STATUTORY AND REGULATORY FRAMEWORK

Section 502(d)(1) of the Act, 42 U.S.C. § 7661a(d)(1), requires each state to develop and submit to EPA an operating permit program to meet the requirements of title V. EPA granted final full approval of the Illinois title V operating permit program effective November 30, 2001. 66 Fed. Reg. 62946 (December 4, 2001).

All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emission limitations and other conditions necessary to assure compliance with applicable requirements of the Act, including the requirements of the applicable State Implementation Plan (SIP). *See* sections 502(a) and 504(a) of the Act, 42 U.S.C. §§ 7661a(a) and 7661c(a). The title V operating permit program generally does not impose new substantive air quality control requirements (referred to as "applicable requirements"), but does require that permits contain monitoring, recordkeeping, reporting, and other requirements sufficient to assure compliance with applicable requirements. 57 Fed. Reg. 32250, 32251 (July 21, 1992). One purpose of the title V program is to "enable the source, States, EPA, and the public to understand better the requirements to which the source is subject, and whether the source is meeting those requirements." *Id.* Thus, the title V operating permit program is a vehicle for ensuring that air quality control requirements are appropriately applied to facility emission units and for assuring compliance with such requirements.

Under section 505(a) of the Act, 42 U.S.C. § 7661d(a), and the relevant implementing regulations at 40 C.F.R. § 70.8(a), states are required to submit each proposed title V operating permit to EPA for review. Upon receipt of a proposed permit, EPA has 45 days to object to final issuance of the permit if EPA determines the permit is not in compliance with applicable requirements or the requirements of part 70. 40 C.F.R. § 70.8(c). Section 505(b)(2) of the Act provides that, if EPA does not object to a permit on its own initiative, any person may petition the Administrator, within 60 days of expiration of EPA's 45-day review period, to object to the permit. 42 U.S.C. § 7661d(b)(2); *see also* 40 C.F.R. § 70.8(d). The petition must "be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided by the permitting agency (unless the petitioner demonstrates in the petition to the Administrator that it was impracticable to raise such objections within such period or unless the grounds for such objection arose after such period)." 42 U.S.C. § 7661d(b)(2). In response to such a petition, the Administrator must issue an objection if a petitioner demonstrates that a permit is not in compliance with the requirements of the Act. *Id.; see also* 40 C.F.R. § 70.8(c)(1); *New York Public Interest Research Group, Inc.* v. *Whitman,* 321 F.3d at 333, n. ll. Under section 505(b)(2) of the Act, 42 U.S.C. § 7661d(b)(2), the burden is on the petitioner to make the required demonstration to EPA. *Sierra Club* v. *Johnson,* 541 F.3d 1257, 1266-1267 (11th Cir. 2008); *Citizens Against Ruining the Environment* v. *EPA,* 535 F.3d 670, 677-678 (7th Cir. 2008); *Sierra Club* v. *EPA,* 557 F.3d 401, 406 (6th Cir. 2009); *McClarence* v. *EPA,* 596 F.3d 1123, 130-31 (9th Cir. 2010) (discussing the burden of proof in title V petitions). If, in responding to a petition, EPA objects to a permit that has already been issued, EPA or the permitting authority will modify, terminate, or revoke and reissue the permit consistent with the procedures set forth in 40 C.F.R. §§ 70.7(g)(4), (5)(i) - (ii) and 70.8(d).

BACKGROUND

USS first applied in March 1996 for a CAAPP title V permit. IEPA determined in May 1996 that the application was complete and published a draft permit for public comment in 2003. USS submitted a supplemental permit application in 2007 to address maximum achievable control technology (MACT) standards. IEPA considered this application a supplement to the 1996 application and, therefore, did not perform a second completeness determination. IEPA issued a new draft CAAPP permit and Project Summary (IEPA's Statement of Basis) for public comment in October 2008. IEPA held a public hearing regarding the new draft permit on December 2, 2008, and provided follow-up answers in January 2009 to questions it could not answer at the time of the hearing. Subsequently, on February 27, 2009, Petitioner submitted written comments on the draft permit to IEPA. EPA received the proposed permit for its 45-day review on June 19, 2009. EPA did not object to the permit, and IEPA issued the final CAAPP permit for the facility, along with a response to public comments, on September 3, 2009.

Under the statutory timeframe in section 505(b)(2) of the Act, 42 U.S.C. § 7661d(b)(2), October 2, 2009, was the deadline to file a petition requesting that EPA object to the final USS permit. Petitioner submitted its petition to EPA on October 1, 2009. Accordingly, EPA finds that Petitioner timely filed its petition.

ISSUES RAISED BY THE PETITIONER

I. The Permit Fails to Include All Applicable Permits and Permit Requirements

Petitioner's Allegations:

Petitioner alleges that IEPA did not include all applicable requirements in the USS title V permit. Petition at 6-9. Specifically, Petitioner points to the emission reduction credits in the IEPA-issued construction permits[1] for cogeneration and the coke plant/coke conveyance system projects[2] (coke plant project permits) that were under construction at the time Petitioner submitted its petition. Petitioner claims that the requirements contained in the permits are applicable requirements, as that term is defined at 415 ILCS 5/39.5(1) and 40 C.F.R. § 70.2,

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[1] Petitioner refers to the following four IEPA-issued new source review permits:
Permit No. 06070022 – Emission Reduction Credits Permit issued January 18, 2007;
Permit No. 06070023 – Cogeneration Project Permit issued January 30, 2008;
Permit No. 06070088 – Coke Conveyance System Permit issued March 13, 2008; and
Permit No. 06070020 – Coke Plant Permit issued March 13, 2008 to Gateway Energy &Coke Company, c/o SunCoke Company.

[2] One of the four permits to which Petitioner cites, Permit No. 06070020, was issued to SunCoke Company. However, in Permit No. 06070020 and in Permit No. 06070088, issued to USS for construction of a coke conveyance system, IEPA noted that the two modifications are considered a single project for purposes of new source review applicability. *See* Permits No. 06070020 and No. 06070088, both at 4.

because IEPA issued the permits pursuant to the State's SIP-approved new source review (NSR) program for major sources and the delegated prevention of significant deterioration (PSD) program. *Id.* at 6-7. Petitioner asserts that the coke plant project constitutes a major source of particulate matter of 2.5 microns or less ($PM_{2.5}$) in a $PM_{2.5}$ nonattainment area, and thus could not proceed without "offsets" of other $PM_{2.5}$ emissions from USS. Petitioner claims that the coke plant project permits reference the IEPA-issued emission reduction credit permit because it provided some of the necessary offsets. *Id.* at 7. Petitioner further claims that, because the provisions of the cogeneration project and coke plant project permits that enabled the project to avoid major NSR are minor source permit requirements, they also must be included in the USS title V permit. *Id.* at 7-8. Petitioner asserts that both the cogeneration and coke plant projects under construction at the time Petitioner submitted the petition rely on netting to avoid major NSR permit requirements. Petitioner alleges that, for a source to rely on netting to avoid permit requirements, it must be bound legally to undertake the emission reductions before it commences construction. *Id.* at 8.

EPA Response:

A title V permit must include all applicable requirements. *See* 40 C.F.R. §§ 70.5(c)(4) and 70.6(a)(1). The term "applicable requirement," as defined in 40 C.F.R. § 70.2 and Illinois' CAAPP regulations, includes "any term or condition of any preconstruction permits issued pursuant to regulations approved or promulgated through rulemaking under title I, including parts C or D, of the Act." In addition, both part 70 and Illinois' CAAPP regulations include in the definition of "applicable requirement" those requirements that will become effective during the term of the title V permit. *See* 40 C.F.R. §§ 70.2, 70.5(c)(4) and (8), and 415 ILCS 5/39.5. In its Responsiveness Summary on this issue, IEPA stated that the "CAAPP permit for U.S. Steel reflects only current operations. [Both the cogeneration and coke plant projects] permitted through construction permits [cited by Petitioner in its comments] are under construction and not operable yet." Responsiveness Summary at 24-25. IEPA did not provide any legal justification for its position that the permit only needed to reflect current operations, nor did it dispute that the PSD permits contained applicable requirements. The facilities that are the subject of the more recently issued NSR permits are [considered by IEPA to be] part of the source that is covered by the title V operating permit under review in this action. Thus by failing to include the provisions of the NSR permits in the title V permit, IEPA has acted contrary to both part 70 and Illinois' CAAPP regulations that define the term "applicable requirement."[3] Based on EPA's and

[3] In stating that the USS CAAPP permit reflects current operations and that sources covered by the preconstruction permits were still under construction, it is possible that IEPA was intending to refer to 40 C.F.R. §70.5(a)(1)(ii). That provision states in relevant part: "Part 70 sources required . . . to have a permit under the preconstruction review program approved into the applicable implementation plan under part C or D of title I of the Act [i.e., the New Source Review program], shall file a complete application to obtain the part 70 permit or permit revision within 12 months after commencing operation or on or before such earlier date as the permitting authority may establish. Where an existing part 70 permit would prohibit such construction or change in operation, the source must obtain a permit revision before commencing operation."

EPA's proposed part 70 rule stated that any source required to have a preconstruction permit under the NSR program would be subject to the part 70 program, but the proposed rule did not address the timing of a title V application. *See* 57 Fed. Reg. 32250, 32271. EPA included 40 C.F.R. 70.5(a)(1)(ii) in the final rule to address this issue and situations where a source had no title V permit or such permit was not up for revision, or where the

Illinois' definition of "applicable requirement," as described above, the emission reduction credits and all other terms of the construction permits issued pursuant to SIP-approved programs are applicable requirements and, as such, must be included in the title V operating permit. I therefore grant the petition on this issue, and direct IEPA to include the requirements for the emission reduction credits in the USS CAAPP permit, as well as all other requirements of the pre-construction permits cited by Petitioner at pages 6 and 9 of the petition.[4] *See In the Matter of Wisconsin Public Service Corporation's JP Pulliam Power Plant,* Petition Number V-2009-01 (June 28, 2010) at 3-5.

II. The Permit Fails to Provide Periodic Monitoring Sufficient to Assure Compliance

Petitioner's Allegations:

Petitioner claims that the USS CAAPP permit does not meet the periodic monitoring requirements of part 70 for various requirements applicable to the coal handling operations, the coke production operations, the coke oven gas by-products recovery plant, the blast furnaces, the basic oxygen furnaces, the continuous casting operations, the hot strip mills, the finishing operations, the boilers, the internal combustion engines, and the gasoline storage and dispensing operations. Petition at 9-28. Petitioner claims that permitting authorities must take the following three steps to satisfy the monitoring requirements of title V:

1. Under 40 C.F.R. § 70.6(a)(3)(i)(A), where existing regulations or underlying permits prescribe monitoring that is appropriate to the timeframe of the emission

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source's existing permit would prohibit construction or a change in operation. As EPA explained in the final rule, a source must submit a title V application generally within 12 months after the date on which the source becomes subject to the title V program. *Id.* at 32272. The Act implies that a source becomes subject to the title V program when operations commence. *Id.* Therefore, a source that receives a preconstruction permit and will be newly subject to title V generally would have 12 months after commencing operation to submit a title V application. 40 C.F.R. § 70.5(a)(1)(ii) follows this reading of the statute, and it "prevents the source from being subject to an enforcement action during the 12-month period that it operates before it applies for an operating permit." *Id.* This rule also addresses when an existing title V source would need to apply for a title V permit revision, and provides that (except in situations where the part 70 permit would prohibit such construction or change in operation) the source must submit its application within 12 months of commencing operations. *Cf.* 40 C.F.R. § 70.7(f)(1)(i).

Importantly, 40 C.F.R. § 70.5(a)(1)(ii) does not provide an exception to the definition of "applicable requirement." Nor is it an exemption from the Act's requirement that all title V permits include conditions to assure compliance with all "applicable requirements . . . including the requirements of the applicable implementation plan." *See* 42 U.S.C. § 7661b. 40 C.F.R. § 70.5(a)(1)(ii) does not apply in a situation where a permitting authority is issuing a title V permit to a source and the source holds preconstruction permits that have been issued. The preconstruction permits are applicable requirements, as noted above, and nothing in the Act or the regulations allows a permitting authority to exclude them from the title V permit.

[4] Petitioner suggests that the terms of the preconstruction permits would not be federally enforceable until they were incorporated into USS's title V permit. *See* Petition at p. 8. EPA disagrees with this assertion. EPA has the authority to enforce preconstruction permits issued pursuant to delegated PSD programs or to SIP-approved major and minor NSR programs regardless of whether they are incorporated into title V permits. *See* Section 113(a)(1) and (a)(3) of the Act, 42 U.S.C. § 7413(a)(1) and (a)(3).

limit and sufficient to assure compliance, the permitting authority must properly incorporate that monitoring requirement into the title V permit.

2. Under 40 C.F.R. § 70.6(a)(3)(i)(B), where there is no previously-established monitoring requirement to correspond to an emission limit, the permitting authority must add "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit."

3. Under 40 C.F.R. § 70.6(c)(1), where there exists a previously-established monitoring requirement corresponding to an emission limit, but that monitoring is not sufficient to assure compliance with limit, the permitting authority must supplement monitoring to assure such compliance.

Petition at 9, citing *Sierra Club v. EPA*, 536 F.3d 673 (D.C. Cir. 2008), *CITGO Refining and Chemicals Company L.P.*, Petition No. VI-2007-01 (May 28, 2009) at 7 and *Premcor Refining Group, Inc.*, Petition No. VI-2007-02) at 7 (May 28, 2009). Petitioner asserts that the United States Court of Appeals for the District of Columbia Circuit made clear in *Sierra Club* that the Act requires augmentation of monitoring requirements where requirements exist but are not adequate to ensure compliance, (Petition at 10, quoting *Sierra Club*, 536 F.3d at 678) and that the Illinois Environmental Protection Act also mandates supplemental monitoring where necessary to ensure compliance. *Id.*, quoting 415 ILCS 5/39.5(7)(b).

Petitioner asserts that the USS CAAPP permit contains numerous conditions that establish emission limits but lack periodic monitoring requirements sufficient to assure compliance with the limits. *Id.* Petitioner also asserts that the Project Summary contains conclusory statements about the monitoring requirements but no justifications for IEPA's monitoring choices, and that IEPA must satisfy the monitoring requirements and provide a rationale for the monitoring, as required by part 70. *Id.* at 11-12. Finally, Petitioner alleges that IEPA failed to respond to its significant comments regarding the adequacy of monitoring in the USS CAAPP permit. *Id.* at 11-12.

EPA Response:

EPA's part 70 monitoring rules (40 C.F.R. § 70.6(a)(3)(i)(A) and (B) and 70.6(c)(1)) are designed to address the statutory requirement that "[e]ach permit issued under [title V] shall set forth . . . monitoring . . . requirements to assure compliance with the permit terms and conditions." 42 U.S.C. § 7661c(c). As a general matter, permitting authorities must take three steps to satisfy the monitoring requirements in EPA's part 70 regulations. First, under 40 C.F.R. § 70.6(a)(3)(i)(A), permitting authorities must ensure that monitoring requirements contained in applicable requirements are properly incorporated into the title V permit. Second, if the applicable requirement contains no periodic monitoring, permitting authorities must add "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." 40 C.F.R. § 70.6(a)(3)(i)(B). Third, if there is some periodic monitoring in the applicable requirement, but that monitoring is not sufficient to assure compliance with permit terms and conditions, permitting authorities must supplement monitoring to assure such compliance. 40 C.F.R. § 70.6(c)(1). *See CITGO* at 6-7.

In addition to meeting these three steps, the rationale for the monitoring requirements selected by a permitting authority must be clear and documented in the permit record (e.g., in the statement of basis). 40 C.F.R. § 70.7(a)(5). The determination of whether monitoring is adequate in a particular circumstance generally is a context-specific determination. The monitoring analysis should begin by assessing whether the monitoring required in the applicable requirement is sufficient to assure compliance with permit terms and conditions. Some factors that permitting authorities may consider in determining appropriate monitoring are: (1) the variability of emissions from the unit in question; (2) the likelihood of a violation of the requirements; (3) whether add-on controls are being used for the unit to meet the emission limit; (4) the type of monitoring, process, maintenance, or control equipment data already available for the emission unit; and (5) the type and frequency of the monitoring requirements for similar emission units at other facilities. The preceding list of factors provides the permitting authority with a starting point for its analysis of the adequacy of the monitoring; the permitting authority also may consider other site-specific factors. *CITGO* at 7-8.

Further, IEPA has an obligation to respond adequately to significant comments on the draft title V permit. Section 502(b)(6) of the Act, 42 U.S.C. § 7661a(b)(6), requires that all title V permit programs include adequate procedures for public notice regarding the issuance of title V operating permits, "including offering an opportunity for public comment." *See* 40 C.F.R. § 70.7(h). It is a general principle of administrative law that an inherent component of any meaningful notice and opportunity for comment is a response by the regulatory authority to significant comments. *Home Box Office v. FCC*, 567 F.2d 9, 35 (D.C. Cir. 1977) ("the opportunity to comment is meaningless unless the agency responds to significant points raised by the public."). *See, also, In the Matter of Louisiana Pacific Corporation*, Petition Number V-2006-3 (Nov. 5, 2007), at 4-5.

The petition sets out approximately 50 instances in the USS title V permit where Petitioner claims IEPA has failed to include sufficient monitoring to assure compliance and/or where IEPA has failed to justify the required monitoring. These issues are addressed below. In sum, in the instances described below where I grant on the monitoring issues raised by Petitioner, IEPA must ensure it has: (1) satisfied the monitoring requirements of 40 C.F.R. § 70.6(a)(3)(i)(A) and (B) and (c)(1); (2) provided a rationale for the monitoring requirements placed in the permit (*see* 40 C.F.R. § 70.7(a)(5)); and (3) responded to significant comments. *CITGO* at 8.

A. Coal Handling Operations

Petitioner's Allegations:

Petitioner alleges that the permit does not include periodic monitoring sufficient to assure compliance with the emission limit for particulate matter of 10 microns or less (PM_{10}) found in Condition 7.1.3(f) of the permit. Petition at 12. Petitioner states that the permit only requires inspections of control equipment and related recordkeeping but does not require any actual monitoring. Petitioner concludes that, because USS must meet the emission limit for PM_{10} on an hourly basis, the permit must be revised to require additional periodic monitoring, such as a continuous emission monitoring system (CEMS) for particulate matter (PM), to assure compliance with the limit. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA claims that the "[r]ecordkeeping requirements of Conditions 7.1.10(b), (d), 5.9.3(d) and inspection requirements of Condition 7.1.8 are sufficient to satisfy requirements of 39.5(7)(d) of the Act and ensure that control device is operated properly." Responsiveness Summary at 27. IEPA's response simply recites the monitoring requirements. IEPA did not provide a sufficient analysis to demonstrate how the monitoring requirements in the USS permit assure compliance with the terms and conditions of the permit, or yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comment.[5] IEPA's response to Petitioner's comment was silent on how Conditions 7.1.10(b) and (d), 5.9.3(d) and the inspection requirements of Condition 7.1.8 are sufficient to assure compliance with the related emissions requirements. Therefore, I grant the petition on this issue.

Petitioner also argues that CEMS should be considered the means to comply with the periodic monitoring requirements of part 70. Although CEMs may be the preferred type of monitoring in some instances, they are not always necessary to assure compliance with applicable requirements. Section 504(b) of the Act, 42 U.S.C. § 7661c(b), provides that "continuous emissions monitoring need not be required if alternative methods are available that provide sufficiently reliable and timely information for determining compliance." *See also, In the Matter of Alliant Energy WPL - Edgewater Generating Station*, Petition Number V -2009-02 (August 17, 2010), at 11.

Petitioner has neither identified an applicable requirement that compels the use of CEMS nor demonstrated that a CEM is the only monitoring that can assure compliance with this particular emission limit. I am ordering IEPA either to explain how the USS permit provides adequate monitoring or to modify the permit to ensure that it contains monitoring sufficient to

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[5] As discussed above, if the applicable requirement contains no periodic monitoring, the permitting authority must add periodic monitoring to the title V permit "sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." 40 C.F.R. § 70.6(a)(3)(i)(B). If the applicable requirement contains some periodic monitoring, but that monitoring is not sufficient to assure compliance with permit terms and conditions, permitting authorities must, "[c]onsistent with paragraph (a)(3) . . . ," add monitoring "sufficient to assure compliance with the terms and conditions of the permit." 40 C.F.R. § 70.6(c)(1). Both of these monitoring rules (40 C.F.R. §§ 70.6(a)(3)(i)(A) and (B) and 70.6(c)(1)) are designed to address the statutory requirement that "[e]ach permit issued under [title V] shall set forth . . . monitoring . . . requirements to assure compliance with the permit terms and conditions." CAA section 504(c). Thus, in evaluating whether the permit contains monitoring sufficient to assure compliance under 40 CFR 70.6(c)(1), EPA believes it is appropriate to consider whether such monitoring is "sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit."

assure compliance with the terms and conditions of the permit. Therefore, I deny the claim seeking an order that IEPA must require the use of CEMS in the USS CAAPP permit.

B.1. Coke Production - Coke Oven Charging, Leaks from Doors, Leaks from Lids, and Leaks from Offtakes

Petitioner's Allegations:

Petitioner alleges that the permit does not include periodic monitoring sufficient to assure compliance with visible emission (VE) limits found in Conditions 7.2.3-1(a) and (c), 7.2.3-2(a) and (b), 7.2.3-3(a) and (b), and 7.2.3-4(a) and (b) of the permit. Petition at 12. Petitioner states that the VE limits are based on state regulations and a state-issued permit for Coke Oven Battery B. *Id.* Petitioner further claims that Condition 7.2.14 provides monitoring methods, but does not require the permittee to monitor for compliance with the VE limits. *Id.* Petitioner notes that IEPA states in its Responsiveness Summary that "daily testing of visual emissions are required by condition 7.2.7-3(a) pursuant to 40 C.F.R. part 63, Subpart L," (sic), but claims that, because the emission limits are not based on and are not equivalent to the limits in the federal MACT regulations, IEPA's statement is unclear. *Id.*, quoting Responsiveness Summary at 27.

EPA Response:

IEPA did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the VE limits, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its response to Petitioner's comments. In any case, as noted above, part 70 requires an analysis in the statement of basis or permit record of how the monitoring is sufficient to assure compliance with permit terms and conditions, or sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit, including any augmentation of monitoring requirements where the state has found that monitoring in applicable requirements is not adequate to assure compliance. 40 CFR § 70.6(a)(3)(i)(B), 70.6(c)(1) and 70.7(a)(5). IEPA's response to Petitioner's comment simply recited the monitoring requirements in the permit and was silent on how the monitoring requirements of 40 C.F.R. part 63, subpart L are related to the emissions requirements in the permit. Therefore, I grant the petition on this issue.

B.2. Coke Production - Combustion (Battery) Stack

Petitioner's Allegations:

Petitioner alleges that the permit does not include periodic monitoring sufficient to assure compliance with the PM emission limits found in Condition 7.2.3-7(a)(i) and (c) of the permit. Petition at 13. Petitioner asserts in both instances that the permit requires a single performance test one year before the renewal date of the permit, even though the PM limits require continuous compliance. *Id.* Petitioner claims that IEPA states in the Responsiveness Summary that "CEMs are generally not required for periodic monitoring." *Id.*, quoting Responsiveness Summary at 26-27. Petitioner claims IEPA's response did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the terms and conditions of the permit. Furthermore, Petitioner alleges that PM CEMs should be required because they are both available and feasible. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "Condition 7.2.7(d) of the final CAAPP addresses testing requirements for coke oven combustion stacks." Responsiveness Summary at 27. IEPA's response simply recites the monitoring requirements in the permit. IEPA did not provide in its response an analysis to demonstrate how the monitoring requirements in Condition 7.2.7(d) of the USS permit are sufficient to assure compliance with the terms and conditions of the permit or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit. Therefore, I grant the petition on this issue.

Petitioner also asserts that CEMS be considered the means to comply with the periodic monitoring requirements of Part 70. As noted above, although CEMs may be the preferred type of monitoring in some instances, they are not always necessary to assure compliance with permit terms and conditions. Section 504(b) of the Act provides that "continuous emissions monitoring need not be required if alternative methods are available that provide sufficiently reliable and timely information for determining compliance." 42 U.S.C. § 7661c(b). *See also, In the Matter of Alliant Energy WPL - Edgewater Generating Station*, Petition Number V -2009-02) (August 17, 2010), at 11.

Petitioner has neither identified an applicable requirement that compels the use of CEMS nor demonstrated that a CEMS is the only monitoring that can assure compliance with the applicable requirements. I am ordering IEPA either to explain how the USS permit provides adequate monitoring or to modify the permit to ensure that it contains monitoring sufficient to assure compliance with the associated permit terms and conditions. Therefore, I deny the claim seeking an order that IEPA must require the use of CEMS in the USS CAAPP permit.

B.3. Coke Production - Bypass/Bleeder Stack Flare

Petitioner's Allegations:

Petitioner alleges that the permit does not include periodic monitoring sufficient to assure compliance with the VE limit found in Condition 7.2.3-8(b) of the permit. Petition at 14. Petitioner claims that, although the permit references the federal MACT regulation that specifies monitoring for visible emissions from flares, the permit does not expressly require USS to monitor flare emissions to assure compliance with the limit. *Id.* Petitioner argues that IEPA's statement in the Responsiveness Summary, that "40 CFR 63.309(h) does not specify the frequency of no visible emissions observations," is inadequate. *Id.*, quoting Responsiveness Summary at 27. Petitioner concludes by asserting that IEPA is required to add periodic monitoring requirements to the permit or provide additional information to justify the monitoring required in the permit. *Id.* at 14.

EPA Response:

IEPA did not explain how the monitoring requirements in the USS permit are sufficient to assure compliance with the associated permit terms and conditions. The fact that 40 C.F.R. § 63.309(h) does not specify a monitoring frequency does not end the analysis. As the permitting authority, IEPA must determine whether the monitoring included in a regulation is sufficient to assure compliance with the permit terms and conditions. If it is not, the permitting authority must supplement the monitoring. Therefore, I grant the petition on this issue.

C. Coke Oven Gas By-Products Recovery Plant

Petitioner's Allegations:

Petitioner alleges that the permit's annual opacity reading requirement for the coke oven by-products flare is not frequent enough to assure compliance with the VE limit found in Condition 7.3.10(a)(i) of the permit. Petition at 14. Petitioner asserts that daily or more frequent monitoring such as the use of video monitoring is reasonable to assure compliance with visible emission limits for flares. *Id.* Petitioner further claims that IEPA's rationale for the monitoring associated with condition 7.3.10(a)(i) is unclear. *Id.* Petitioner notes that IEPA stated in its Responsiveness Summary that "[f]laring events are not frequent due to the use of this material as a fuel." *Id.*, quoting Responsiveness Summary at 28. Petitioner concludes that, to assure that monitoring requirements are sufficient, IEPA must clearly explain the frequency and duration of flaring events, and must provide additional information to justify the monitoring requirements associated with Condition 7.3.10(a)(i).

EPA Response:

In its Responsiveness Summary, IEPA states that "[r]egular monthly ignition system inspections... would assure that flare system operates properly. Video monitoring of flare is not needed due to established testing provisions of Condition 7.3.8(c)(vi), inspection requirements of Condition 7.3.9 and the recordkeeping requirements of Condition 7.3.11(c)(iv)(D)." Responsiveness Summary at 28. While IEPA addressed why it thought video monitoring is not needed, IEPA's response did not provide an analysis to demonstrate how the annual opacity reading or the monthly ignition system inspections are sufficient to assure compliance with the no visible emission limit or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit. IEPA refers to the frequency of flaring events but does not provide any support for this and how it justifies an annual reading. Therefore, I grant the petition on this issue.

D.1. Blast Furnace - Control Equipment

Petitioner's Allegations:

Petitioner alleges that the permit does not include periodic monitoring sufficient to assure compliance with the PM emission limit found in Condition 7.4.3-1(a)(ii)(A) of the permit. Petition at 15. Petitioner asserts that a one-time performance test during the permit term (once every 5 years) does not constitute periodic monitoring. *Id.* Petitioner further asserts that IEPA's rationale for the monitoring requirements associated with Condition 7.4.3-1(a)(ii)(A) is inadequate. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "the monitoring and testing procedures outlined in Subsection 7.4 of the final CAAPP and the MACT standard are sufficient enough to demonstrate continuous compliance with the applicable emission standards." Responsiveness Summary at 29. IEPA's response recites the monitoring requirements and asserts that they are sufficient. IEPA's response does not provide an analysis to demonstrate how a performance test once every 5 years as required in the USS permit is sufficient to assure compliance with the terms and conditions of the permit, or is sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's allegations. Therefore, I grant the petition on this issue.

D.2. Blast Furnaces – Opacity

Petitioner's Allegations:

Petitioner alleges that the weekly opacity readings required in the permit are not sufficient to assure compliance with the visible emission limit found in Condition 7.4.3-1(d)(ii) of the permit. Petitioner also states that IEPA's response confuses matters as it refers to once-a-permit-term monitoring based on a MACT standard. Petitioner requests daily or more frequent opacity monitoring, including the use of video monitoring. Petition at 15.

EPA Response:

In addition to Condition 7.4.7-2(b)(i)(C)(1), which requires weekly opacity observations, IEPA refers in its Responsiveness Summary to once-a-permit-term monitoring in Condition 7.4.7-2(a)(ii). "[40 C.F.R. §] 63.7821(c) requires that '...For each emission unit equipped with a baghouse, you must conduct subsequent performance tests no less frequently than once during each term of your title V operating permit.' Therefore, Condition 7.4.7-2(a)(ii) of the final CAAPP correctly identifies frequency of subsequent testing. The IEPA believes that the monitoring and testing procedures outlined in Subsection 7.4 of the final CAAPP and the MACT standard are sufficient enough to demonstrate continuous compliance with the applicable emission standards." Responsiveness Summary at 29. EPA agrees it is unclear what monitoring requirements apply for purposes of the visible emission limit. Moreover, IEPA's response simply recites the monitoring requirements and concludes that they are sufficient. IEPA's response did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the terms and conditions of the permit or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. Therefore, I grant the petition on this issue.

D.3 Blast Furnace - Excess Gas Flare

Petitioner's Allegations:

Petitioner alleges that the annual opacity observations and monthly inspections of the flare ignition system required in the permit are not sufficient to assure compliance with the no visible emission limit found in Condition 7.4.5-4(e) of the permit, which applies on a continuous basis. Petitioner requests daily or more frequent monitoring, including the use of video monitoring. Petition at 15-16.

EPA Response:

In its Responsiveness Summary, IEPA states that "Condition 7.4.7-1 of the final CAAPP establishes monthly inspection requirements of the flare's ignition system. Condition 7.4.7-2(c) of the final CAAPP requires annual observations of a flare by using USEPA Method 22. Video monitoring of flare is not needed due to the inspection and testing requirements referenced above." Responsiveness Summary at 28. IEPA's response simply recites the monitoring requirements, but does not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the terms and conditions of the permit, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. Therefore, I grant the petition on this issue.

D.4 Blast Furnaces – Production and Emission Limits

Petitioner alleges that the permit does not include periodic monitoring sufficient to assure compliance with the emission limits in Conditions 7.4.6(b)-(g) for the blast furnaces and related operations. Petitioner alleges that compliance with these conditions is demonstrated through the use of iron production records and emission factors established in PSD permit 95010001. Petition at 16. Petitioner alleges that neither the title V nor the PSD permit identifies the source of the emission factors. Further, Petitioner asserts that neither the Project Summary nor the Responsiveness Summary provides evidence that the emissions factors are representative of the emissions at the USS facility. *Id.* Petitioner concludes that IEPA must provide additional information about the source of the data used to calculate the emission factors and must clearly explain how the use of the emission factors is sufficient to assure compliance with the associated emission limits. *Id.* at 17. Petitioner makes additional specific allegations for each emission limit in the sections below.

a. Casthouse Baghouse (Furnace Tapping) Captured Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the PM_{10} emission limit found in Condition 7.4.6(b) of the permit as it relies on an emission factor from an unspecified source. *Id.* Petitioner further disagrees with IEPA's explanation that, in addition to the use of emission factors, testing requirements based on federal MACT regulations will be used to assure compliance with the PM_{10} emission limit in Condition 7.4.6(b), stating that the testing requirements are based on federal MACT regulations which do not apply to this permit condition. *Id.* Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "The IEPA believes that the monitoring and testing procedures outlined in Subsection 7.4 of the final CAAPP and the MACT standard are sufficient enough to demonstrate continuous compliance with the applicable emission standards." Responsiveness Summary at 29. IEPA did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the PM_{10} emission limits, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its response to Petitioner's comments. IEPA's response to Petitioner's comment simply recited the monitoring requirements in the permit and was silent on how the monitoring requirements of the MACT are related to the emissions requirements in the permit.

The record for the USS permitting action does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. With a few exceptions, EPA does not recommend the use of emission factors to develop source-specific permit limits or to determine compliance with permit requirements. *In the Matter of Tesoro Refining and Marketing Co, Martinez, California Facility,* Petition Number IX-2004-6 (March 15, 2005) at 32. I grant the petition on the monitoring issues related to such use of emission factors. IEPA either must justify in the record why these emission factors are representative of USS's operations (i.e., representative to yield reliable data from the relevant time period representative of the sources compliance), and provide sufficient evidence to demonstrate that the emissions will not vary by a degree that would cause an exceedance of the standards, or IEPA must determine and adequately support another mechanism to assure compliance with the applicable emission limits from the underlying construction permit. Furthermore, if IEPA can adequately justify the use of emission factors as a compliance mechanism, it also should require USS to confirm the appropriateness of the emission factors such as through the use of stack testing using EPA-approved methods on a periodic basis, as operations and equipment change or deteriorate over time.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the sulfur dioxide (SO_2) emission limit found in Condition 7.4.6(b) of the permit as it relies on an emission factor from an unspecified source. Petition at 17. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA refers to the monitoring for a different unit, the iron spout baghouse. Responsiveness Summary at 29. The record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the nitrogen oxides (NO_x) emission limit found in Condition 7.4.6(b) of the permit as it relies on an emission factor from an unspecified source. Petition at 18. According to Petitioner, IEPA has not provided further information on the "initial testing data" referenced in the Responsiveness Summary, making it difficult to determine whether testing is representative of NO_x emissions from the casthouse baghouse. Petitioner asserts that a margin of compliance is not a sufficient basis for a determination that emissions will not change over the life of the permit. *Id.* Petitioner further claims that IEPA's rationale for the monitoring requirements associated with the NO_x emission limit in Condition 7.4.6(b) is far too general. Petitioner concludes that IEPA must provide additional information to justify this monitoring condition or must revise the permit to require additional periodic monitoring. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states "The initial testing data indicates the actual level of NOx emissions from casthouse baghouse is almost three times lower than the allowable levels established in this condition. Therefore, application of CEMS is unnecessary. The IEPA believes that the monitoring and testing procedures outlined in Subsection 7.4 of the final CAAPP and the MACT standard are sufficient enough to demonstrate continuous compliance with the applicable emission standards." Responsiveness Summary at 30. EPA agrees that the record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue. Absent appropriate permit conditions limiting operations and inputs, initial testing data cannot be assumed to reflect the potential for variability in emissions. Operating conditions may change and a margin of compliance alone is not a sufficient safeguard in light of this potential for variability in operations and inputs, and consequently, emissions.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the volatile organic material (VOM) emission limit found in Condition 7.4.6(b) of the permit as it relies on an emission factor from an unspecified source. Petition at 18. According to Petitioner, IEPA has not provided further information on the "initial testing data" referenced, making it difficult to determine whether testing is representative of VOM emissions under maximum operating conditions of the blast furnaces. Petitioner asserts that a margin of compliance alone is not a sufficient basis to determine that emissions will not change over the life of the permit. *Id.* Petitioner concludes that IEPA must provide additional information to justify this monitoring condition or must revise the permit to require additional periodic monitoring. *Id.* at 18-19.

EPA Response:

In its Responsiveness Summary, IEPA states that "The initial testing data indicates the actual level of VOM emissions from casthouse baghouse is eight times lower than the allowable levels established in this condition. Because of such large margin of compliance, the IEPA does not support suggestions of VOM annual tests." Responsiveness Summary at 30. EPA agrees that the record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

b. Blast Furnace Uncaptured Fugitive Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the SO_2 emission limit found in Condition 7.4.6(c) of the permit as it relies on an emission factor from an unspecified source. Petition at 19. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states "condition 7.4.7-2(b)(i) of the final CAAPP establishes weekly visual observations of fugitive emissions released from the casthouse and supported by appropriate recordkeeping." Responsiveness Summary at 30. Condition 7.4.7-2(b)(i) of the final CAAPP refers to opacity testing. IEPA's response did not provide an analysis to demonstrate how the opacity monitoring requirements in the USS permit are sufficient to assure compliance with the uncaptured SO_2 emissions, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. The record also does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the NO_x emission limit found in Condition 7.4.6(c) of the permit as it relies on an emission factor from an unspecified source. Petition at 19. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states "condition 7.4.7-2(b)(i) of the final CAAPP establishes weekly visual observations of fugitive emissions released from the casthouse and supported by appropriate recordkeeping." Responsiveness Summary at 31. Condition 7.4.7-2(b)(i) of the final CAAPP refers to opacity testing. IEPA's response did not provide an analysis to demonstrate how the opacity monitoring requirements in the USS permit are sufficient to assure compliance with the uncaptured NO_x emissions, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. The record also does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the VOM emission limit found in Condition 7.4.6(c) of the permit as it relies on an emission factor from an unspecified source. Petition at 19. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states "condition 7.4.7-2(b)(i) of the final CAAPP establishes weekly visual observations of fugitive emissions released from the casthouse and supported by appropriate recordkeeping." Responsiveness Summary at 31. Condition 7.4.7-2(b)(i) of the final CAAPP refers to opacity testing. IEPA's response did not provide an analysis to demonstrate how the opacity monitoring requirements in the USS permit are sufficient to assure compliance with the uncaptured VOM emissions, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. The record also does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

c. Blast Furnace Charging Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the PM_{10} emission limit found in Condition 7.4.6(d) of the permit as it relies on an emission factor from an unspecified source. Petition at 19. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "Condition 7.4.11(f) of the final CAAPP does require [USS] to keep records of iron pellets charged to Blast Furnace. These records in conjunction with established emission factors are sufficient to establish actual emissions and to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the Act. Also, iron pellet charging does not have individual emission stack and that makes testing impossible." Responsiveness Summary at 32. EPA agrees that IEPA's response did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the terms and conditions of the permit, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. The record also does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

d. Slag Pits Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the PM_{10} emission limit found in Condition 7.4.6(e) of the permit as it relies on an emission factor from an unspecified source. Petition at 20. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "Condition 7.4.11(g) of the final CAAPP does require [USS] to keep records of slag processed. These records in conjunction with established emission factors are sufficient to establish actual emissions and to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the [Illinois Environmental Protection] Act. Also, slag pits do not have emission stack and that makes testing impossible." Responsiveness Summary at 32. EPA agrees that IEPA's response did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the terms and conditions of the permit, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. The record also does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the SO_2 emission limit found in Condition 7.4.6(e) of the permit as it relies on an emission factor from an unspecified source. Petition at 20. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states "condition 7.4.7-2(b)(i) of the final CAAPP establishes weekly visual observations of fugitive emissions released from the casthouse and supported by appropriate recordkeeping." Responsiveness Summary at 31. Condition 7.4.7-2(b)(i) of the final CAAPP refers to opacity testing for the casthouse. Neither IEPA's Project Summary nor its response to Petitioner's comments provided an analysis to demonstrate how the opacity monitoring requirements in the USS permit are sufficient to assure compliance with the uncaptured SO_2 emissions for the slag pits, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit. The record also does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

e. Iron Spout Baghouse Captured Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the PM_{10} emission limit found in Condition 7.4.6(f) of the permit as it relies on an emission factor from an unspecified source. Petition at 20. Petitioner also claims that the Responsiveness Summary is confusing regarding this monitoring requirement because it suggests that testing requirements from federal MACT requirements will be used to assure compliance with the PM_{10} emissions limit in Condition 7.4.6(e). *Id.* Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that the "Condition 7.4.9(a)(ii) of the final CAAPP clearly identifies that each baghouse is equipped with a bag leak detection system. IEPA believes that the monitoring and testing procedures outlined in Subsection 7.4 of the final CAAPP and the MACT standard are sufficient enough to demonstrate continuous compliance with the applicable emission standards." Responsiveness Summary at 32. IEPA did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the PM_{10} emissions limits, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its response to Petitioner's comments. IEPA's response to Petitioner's comment simply recited the monitoring requirements in the permit and was silent on how the monitoring requirements of the MACT are related to the emissions requirements in the permit.

Further, the permitting record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility.

IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the SO_2 emission limit found in Condition 7.4.6(f) of the permit as it relies on an emission factor from an unspecified source. Petition at 20. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.* at 20-21.

EPA Response:

In its Responsiveness Summary, IEPA refers to the monitoring for a different unit, the casthouse baghouse. *See* Responsiveness Summary at 31. IEPA's response did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the terms and conditions of the permit, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. The record also does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

f. Iron Pellet Screen Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the PM_{10} emission limit found in Condition 7.4.6(g) of the permit as it relies on an emission factor from an unspecified source. Petition at 21. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "Condition 7.4.11(h) of the final CAAPP does require [USS] to keep records of iron pellets screened. These records in conjunction with the established emission factors are sufficient to establish actual emissions and to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the Act. Also, pellet screening does not have individual emission stack and that makes testing impossible." Responsiveness Summary at 33. EPA agrees that IEPA's response did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the terms and conditions of the permit, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. The record also does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

E.1. Basic Oxygen Furnaces (BOF) – Opacity

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the frequency of the monitoring requirements for the opacity limit found in Condition 7.5.3-1(c)(iv) of the permit. Condition 7.5.3-1(c)(iv) sets an opacity limit of 20 percent based on 3 minute averages for any secondary emissions that exit any opening in the basic oxygen process furnace (BOPF) shop or any other building housing the BOPF or BOPF shop operation. Condition 7.5.7-2(d) requires weekly opacity observations for uncaptured roof monitor emissions unless a previous observation measures opacity of 20 percent or more. If a previous observation measures opacity of 20 percent or more, daily monitoring is required until five consecutive observations are less than 20 percent. Petition at 21. Petitioner alleges that daily observations using EPA Method 9 are supported by EPA's April 18, 1997, *Region 7 Policy on Periodic Monitoring for Opacity* (Region 7 guidance) for title V permits, and that the permit must be revised to require at least daily opacity observations to assure compliance with the limit. Petitioner asserts that IEPA must provide additional information to justify the monitoring frequency given in the permit.

EPA Response:

In its Responsiveness Summary, IEPA states that "Condition 7.5.7-2(d) of the final CAAPP identifies frequency (weekly and daily) of roof monitor opacity visual observations." Responsiveness Summary at 37. EPA agrees that IEPA's response did not provide an analysis to demonstrate how the frequency of the monitoring requirements in the USS permit is sufficient to assure compliance with the terms and conditions of the permit, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. Therefore, I grant the petition on this issue. However, I note that the Region 7 guidance, which recommends daily observations for opacity monitoring, provides guidance to permitting authorities, but does not contain any requirements; therefore, IEPA does not have to use the monitoring methods discussed in the Region 7 guidance. Regardless of the monitoring method it includes in the USS permit, IEPA must fully explain the bases for and sufficiency of its choice of monitoring.

Petitioner's Allegations:

Petitioner alleges that the permit lacks periodic monitoring requirements sufficient to assure compliance with the opacity limit found in Condition 7.5.3-1(f) of the permit. Petition at 21. Petitioner asserts that IEPA must provide additional information to justify this monitoring condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "MACT presented in Subpart FFFFF does not require visual observation frequencies other than those established in the permit. Condition 7.5.7-1(c)(1) of the final CAAPP identifies frequency (weekly) of opacity readings from BOF shop openings. This is sufficient to yield compliance with Condition7.5.3-1(f)." Responsiveness Summary at 37. IEPA did not provide an analysis to demonstrate how the monitoring requirements in the USS permit are sufficient to assure compliance with the visible emissions limit in 7.5.3-1(f), or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its response to Petitioner's comments. IEPA's response to Petitioner's comment simply recited the monitoring requirements in the permit and was silent on how the monitoring requirements of 40 C.F.R. part 63, subpart FFFFF are related to the emissions requirements in the permit. Therefore, I grant the petition on this issue.

E.2. Basic Oxygen Furnaces – Production and Emission Limits

Petitioner alleges that the permit does not include periodic monitoring sufficient to assure compliance with the emission limits in conditions 7.5.6(c)-(i) for the basic oxygen furnaces and related operations. Petition at 22. Petitioner alleges that compliance with these conditions is demonstrated through the use of steel production records and emission factors established in PSD permit 95010001. *Id.* Petitioner alleges that neither the title V nor the PSD permit identifies the source of the emission factors. Further, Petitioner asserts that neither the Project Summary nor the Responsiveness Summary provides evidence that the emissions factors are representative of the emissions at the USS facility. *Id.* Petitioner concludes that IEPA must provide additional information about the source of the data used to calculate the emission factors and must clearly explain how the use of the emission factors is sufficient to assure compliance with the associated emission limits. *Id.* Petitioner raises specific issues for each emission limit, and they are discussed in the sections below.

a. BOF Electrostatic Precipitator (ESP) Stack Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the NO_x limit found in Condition 7.5.6(c) of the permit. Condition 7.5.6(c) sets a NOx emission limit of 69.63 tpy for the BOF ESP stack. Petitioner alleges that both the Project Summary and the Responsiveness Summary fail to include information necessary to justify the use of the NO_x emission factor to assure compliance with the limit. According to IEPA, the emission factor is based on the testing of NO_x emissions performed by the source. However, IEPA does not provide information on the testing data used to develop the emission factors, other than the fact that testing occurred. *Id.* Petitioner asserts that IEPA must provide additional information to justify these monitoring conditions. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "NO_x emission limits and emission factor had been established in the production increase construction permit 95010001 and based on the testing of NO_x emissions performed by the source. This data along with the steel production records are sufficient to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the Act." Responsiveness Summary at 33. However, IEPA has not made clear how the emission factors are indicative of the emissions at USS's facility, since it has failed to include in either the Responsiveness Summary or the permit record specific information on the testing of NOx emissions or references to the tests performed. IEPA has failed to explain how the use of the emission factors in conjunction with the production records is adequate to assure compliance. Therefore, I grant the petition on this issue.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the VOM limit found in Condition 7.5.6(c) of the permit. Condition 7.5.6(c) sets a VOM emission limit of 10.74 tpy for the BOF ESP stack. Petitioner alleges that both the Project Summary and the Responsiveness Summary fail to include information necessary to justify the use of the VOM emission factor to assure compliance with the limit. Petition at 22-23. According to IEPA, the emission factor is based on the testing of VOM emissions performed by the source. However, IEPA does not provide information on the testing data used to develop the emission factors, other than the fact that testing occurred. A single stack test cannot reflect the variability in emissions throughout the range of operating conditions of the blast furnaces or the potential for emissions to change over time. Petitioner asserts that IEPA must provide additional information to justify these monitoring conditions. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "VOM emission limits and emission factor had been established in the production increase construction permit 95010001 and based on the testing of VOM emissions performed by the source. This along with the steel production records are sufficient to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the Act. 35 IAC 219.301 regulates organic photochemical reactive materials (mostly solvents) and/or organic materials having odor nuisance. Organic solvents are not used at BOF and no odor problems directly attributed to BOF have been adjudicated or confirmed." Responsiveness Summary at 34. However, IEPA has not made clear in the permitting record how the emission factors are indicative of the emissions at USS's facility, since it has failed to include in either the Responsiveness Summary or the permit record specific information on the testing of NOx emissions or references to the tests performed. IEPA has failed to explain how the use of the emission factors in conjunction with the production records is adequate to assure compliance. Therefore, I grant the petition on this issue.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the carbon monoxide (CO) limit found in Condition 7.5.6(c) of the permit, stating that both the Project Summary and the Responsiveness Summary fail to include information necessary to justify the use of the CO emission factor to assure compliance with the limit. According to IEPA, the emission factor is based on the testing of CO emissions performed by the source and has a margin of compliance of ten times the actual emissions measured during a stack test. However, IEPA does not provide information on the testing data used to develop the emission factors, other than the fact that testing occurred. Petition at 23. Petitioner asserts that IEPA must provide additional information to justify these monitoring conditions. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "CO emission limit and emission factor had been established in the production increase construction permit 95010001 and based on the testing of CO emissions performed by the source (actual stack test results conducted in October 2006 demonstrate CO emission 10 times lower than established 95010001 permit). All these, along with the steel production records, are sufficient to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the Act." Responsiveness Summary at 34. However, IEPA has not made clear in the permitting record how the emission factors are indicative of the emissions at USS's facility, since it has failed to include in either the Responsiveness Summary or the permit record specific information on the testing of CO emissions or references to the tests performed. IEPA has failed to explain how the use of the emission factors in conjunction with the production records is adequate to assure compliance. In addition, although IEPA states that there is a large margin of compliance (stating actual emissions are ten times lower than the permit limit), there is no information in either the Responsiveness Summary or the permit record which addresses the variability in emissions. Therefore, I grant the petition on this issue.

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the lead limit found in Condition 7.5.6(c) of the permit, stating that both the Project Summary and the Responsiveness Summary fail to include information necessary to justify the use of the lead emission factor to assure compliance with the limit. Furthermore, Petitioner is concerned that the emissions limit is much higher than necessary given the emission factor cited by the permit. Petition at 23. Petitioner asserts that IEPA must provide additional information to justify these monitoring conditions. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "The most significant source of lead emissions from BOF shop is a BOF ESP stack (see Condition 7.5.6(c)). The initial testing data indicates the actual level of lead emissions from ESP stack is around 3.5% of the allowable levels established in this condition." Responsiveness Summary at 35. However, IEPA does not make clear in the permitting record how the emission factors are indicative of the emissions at USS's facility or how the use of the emission factors in conjunction with the production records is adequate to assure compliance. IEPA has failed to provide an explanation why use of the emission factors is adequate to assure compliance. Therefore, I grant the petition on this issue.

b. BOF Roof Monitor Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the lead limit found in Condition 7.5.6(d) of the permit as it relies on an emission factor from an unspecified source. Although IEPA responds that there is a generous margin of compliance between actual testing emissions data and the emissions limit given in the permit, Petitioner alleges that IEPA has provided no further information to explain the source of these conservative estimates and how they are sufficient to assure compliance with the limit. Petition at 24. Petitioner asserts that IEPA must provide additional information to justify these monitoring conditions. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that its limits are "based on conservative estimates whereas the actual emissions still maintain a generous margin of compliance." Responsiveness Summary at 35. The record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide the source of the emission factors and explain how the use of the emission factors in conjunction with production records is adequate to assure compliance. IEPA must also explain in the record how the margin of compliance is adequate, and that variability in emissions will not result in an exceedance of the emission limits. Therefore, I grant the petition on this issue.

c. Desulfurization and Reladling (Hot Metal Transfer) Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the VOM limit found in Condition 7.5.6(e) of the permit, stating that both the Project Summary and the Responsiveness Summary fail to include information necessary to justify the use of the VOM emission factor to assure compliance with the limit. Petition at 24. Petitioner alleges that, although IEPA claims that its emission limit is based on engineering estimates, it does not explain what engineering estimates were used to develop the emission limit and how those estimates are representative of desulfurization and reladling emissions at USS's facility. Petitioner asserts that IEPA must provide additional information to justify these monitoring conditions. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "VOM emission limits and emission factor had been established in the production increase construction permit 95010001 and based on the testing of VOM emissions performed by the source. This along with the steel production records are sufficient to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the Act." Responsiveness Summary at 34. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide the source of the emission factors or engineering estimates and explain how the use of the emission factors in conjunction with production records is adequate to assure compliance. Therefore, I grant the petition on this issue.

Petitioner's Allegations:

Condition 7.5.6(e) sets a lead emission limit of 0.09 tpy for desulfurization and reladling (hot metal transfer) emissions. Petitioner alleges that IEPA has not provided a clear rationale for the monitoring requirements associated with this limit as it relies on an emission factor from an unspecified source. The Responsiveness Summary states that the limit is "based on conservative estimates where as the actual emissions still maintain a generous margin of compliance."However, Petitioner alleges that IEPA has provided no further information to explain the source of these conservative estimates and how they are sufficient to assure compliance with the limit. Petitioner asserts that IEPA must provide additional information to justify the monitoring requirements associated with this condition. Petition at 24. Petitioner asserts that if IEPA cannot provide sufficient justification, the permit must be revised to require additional periodic monitoring, such as an annual stack test, to assure compliance with the lead limit. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "All other much smaller limits for lead emissions listed by commenter are based on conservative estimates where as the actual emissions still maintain a generous margin of compliance." Responsiveness Summary at 35.

In the case of the USS permit action, the record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has failed to provide the source of the emission factors and an explanation of why the use of the emission factors is adequate to assure compliance. IEPA must also explain in the record how the margin of compliance is adequate, and that variability in emissions will not result in an exceedance of the emission limits. Therefore, I grant the petition on this issue.

d. BOF Additive System Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the PM_{10} limit found in Condition 7.5.6(f) of the permit, stating that both the Project Summary and the Responsiveness Summary fail to include information necessary to justify the use of the emission factor to assure compliance with the limit. Petition at 25. Petitioner asserts that IEPA must provide additional information to justify these monitoring conditions. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "The quantity of PM10 emissions from the BOF Additive system controlled by a hopper baghouse when compared to the BOF primary operations is minor. PM10 emission factors, along with the steel production records, are sufficient to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the Act. Coupled with inspection requirements, the likelihood of exceedance is minimal." Responsiveness Summary at 36. The record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has also failed to explain how the use of the emission factors in conjunction with production records is adequate to assure compliance. Therefore, I grant the petition on this issue.

e. Flux Conveyor, Transfer Pits, and Binfloor Emissions

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the PM_{10} limit found in Condition 7.5.6(g) of the permit, stating that both the Project Summary and the Responsiveness Summary fail to include information necessary to justify the use of the emission factor to assure compliance with the limit. Petition at 25. Petitioner asserts that IEPA must provide additional information to justify these monitoring conditions. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "PM10 emission factors, along with the steel production records, are sufficient to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the Act. Coupled with inspection requirements, the likelihood of exceedance is minimal." Responsiveness Summary at 36. The record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has also failed to explain how the use of the emission factors in conjunction with production records is adequate to assure compliance. Therefore, I grant the petition on this issue.

f. Emissions from the Argon Stirring Station and Material Handling Tripper

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the PM_{10} limit found in Condition 7.5.6(i) of the permit, stating that both the Project Summary and the Responsiveness Summary fail to include information necessary to justify the use of the emission factor to assure compliance with the limit. Petition at 25. Petitioner asserts that IEPA must provide additional information to justify these monitoring conditions. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "PM10 emission factors, along with the steel production records, are sufficient to meet monitoring requirements pursuant 39.5(7)(d)(ii) of the Act. Coupled with inspection requirements, the likelihood of exceedance is minimal." Responsiveness Summary at 36. The record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has also failed to explain how the use of the emission factors in conjunction with production records is adequate to assure compliance. Therefore, I grant the petition on this issue.

F.1. Continuous Casting - Opacity

Petitioner's Allegations:

Petitioner alleges that the permit record does not provide a clear rationale for the monitoring requirements for the five percent opacity limit for the continuous caster spray chambers or continuous casting operations set in Condition 7.6.3-1(b)(ii) of the permit. Petition at 25. According to Petitioner, the USS permit requires weekly opacity observations for uncaptured roof monitor emissions, or daily observations if a previous observation measured five percent opacity or more, until five consecutive readings measure less than five percent opacity. *Id.* Petitioner asserts that IEPA has not provided a rationale that demonstrates that this monitoring is "sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." *Id.* Petitioner concludes that IEPA must revise the permit to require at least daily opacity observations to assure compliance with the opacity limit. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "Changes have been made. Condition 7.6.8-1(c)(i) of the final CAAPP identifies frequency (weekly and daily) of opacity reading from continuous casting operations." Responsiveness Summary at 38. In addition, IEPA refers to previous responses in which it contends that there is no stack in which to install a monitor or to perform a stack test. *Id.* Although IEPA addressed why it believed a continuous opacity monitor is not necessary, IEPA's response did not provide an analysis to demonstrate how the weekly (and potentially daily) opacity observations are adequate to assure compliance with the five percent opacity limit, or are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. IEPA refers to the frequency of the opacity readings from continuous casting operations, but does not provide any support for how it justifies the weekly (or daily) readings. Therefore, I grant the petition on this issue.

F.2. Continuous Casting - Production and Emission Limits

Petitioner's Allegations:

Petitioner alleges that the permit does not include periodic monitoring sufficient to assure compliance with the PM_{10} and NO_x emission limits in Conditions 7.6.7(a)-(e) for the continuous casting and related operations. Petitioner alleges that compliance with this condition is demonstrated through the use of steel production records and emission factors established in PSD permit 95010001. Petition at 25. Petitioner alleges that neither the title V nor the PSD permit identifies the source of the emission factors. Further, Petitioner asserts that neither the Project Summary nor the Responsiveness Summary provides evidence that the emissions factors are representative of the emissions at USS's facility. *Id.* at 25-26. Petitioner concludes that IEPA must provide additional information about the source of the data used to calculate the emission factors and must clearly explain how the use of the emission factors is sufficient to assure compliance with the associated emission limits. *Id.* at 26.

EPA Response:

In its Responsiveness Summary regarding Condition 7.6.7(b), IEPA asserts that "No changes were made. There is no stack for caster molds with which to install a monitor and/or perform a stack test. Emission factors and recordkeeping requirements are sufficient to yield compliance with Condition 7.6.7(b)." For Conditions 7.6.7(a-e), IEPA responds, "No changes were made. Number of operations from above do not have individual stacks and emissions associated with those units are uncaptured and/or not controlled. Emission factors, recordkeeping requirements and opacity reading are sufficient to yield compliance with different emission limits of Condition 7.6.7." Responsiveness Summary at 38.

The permit record does not specify the origin of the emission factors. It is not clear whether the emission factors used by IEPA are indicative of the emissions at USS's facility. IEPA has also failed to explain how the use of the emission factors in conjunction with production records is adequate to assure compliance. Therefore, I grant the petition on this issue.

G.1. Hot Strip Mill - Slab Reheat Furnaces

Petitioner's Allegations:

Petitioner alleges the permit does not include periodic monitoring sufficient to assure compliance with the PM_{10} limit in Condition 7.7.3-1. Petition at 26. The requirement to test once in five years at the time of renewal of the title V permit for compliance with this condition does not constitute period monitoring and is not "sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." *Id.* Petitioner concludes that, because USS must comply with the PM limit on a continuous basis, the permit must require additional periodic monitoring such as the use of a PM CEMS to assure compliance with the limit. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "Changes have been made. Condition 7.7.8(d) of the final CAAPP establishes frequency of testing PM 10 emissions (once in five years at the time of CAAPP renewal) from slab reheat furnaces. Also, PM CEM's do not measure PM10 directly." Responsiveness Summary at 39. Although IEPA addresses why it believes a CEMS is not necessary, IEPA's response did not provide an analysis to demonstrate how the testing once every five years is adequate to assure compliance with the PM_{10} limit, or is sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. IEPA refers to the frequency of the PM_{10} readings from the hot strip mill slab reheat furnace operations, but does not provide any support for this or how it justifies the testing frequency of once every five years. Therefore, I grant the petition on this issue.

Petitioner also suggests that CEMS be considered the means to comply with the periodic monitoring requirements of part 70. Although CEMS may be the preferred type of monitoring in some instances, they are not always necessary to assure compliance with applicable requirements. Section 504(b) of the Act provides that "continuous emissions monitoring need not be required if alternative methods are available that provide sufficiently reliable and timely information for determining compliance." 42 U.S.C. § 7661c(b). *See also, In the Matter of Alliant Energy WPL - Edgewater Generating Station*, Petition Number V -2009-02) (August 17, 2010), at 11.

Petitioner has neither identified an applicable requirement that compels the use of CEMS nor demonstrated that a CEMS is the only monitoring that can assure compliance with the applicable requirements. I am ordering IEPA either to explain how the USS permit provides adequate monitoring or to modify the permit to ensure that it contains monitoring sufficient to assure compliance with the applicable requirements. Therefore, I deny the claim in the petition seeking an order that IEPA must require the use of CEMS in the USS CAAPP permit.

G.2. Hot Strip Mill - Production and Emission Limits

Petitioner's Allegations:

Petitioner asserts that the permit does not include periodic monitoring sufficient to assure compliance with the PM_{10} emission limits found in Condition 7.7.7(b) of the permit. Petition at 26. Petitioner claims that, although Condition 7.7.7(b) requires compliance with a maximum hourly heat input limit, Condition 7.7.10(b) requires only that USS keep a monthly log of fuel usage. *Id.* at 26-27. Petitioner asserts that the permit must contain an hourly fuel usage recordkeeping requirement.

EPA Response:

In its Responsiveness Summary, IEPA states that "Condition 7.7.7(b) of the final CAAPP was revised in order to remove obsolete total heat input of all reheat slab furnaces (1915 million BTU per hour). Current total maximum heat input is 1/3 lower than that limit." Responsiveness Summary at 39. IEPA concedes that the previous limit was obsolete. However, its response did not provide an analysis to demonstrate how the new heat input limit is adequate to assure compliance with the PM_{10} limit, nor explain why the monthly fuel log is sufficient to assure compliance with the permit terms or yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. Therefore, I grant the petition on this issue.

H. Finishing Operations

Petitioner's Allegations:

Petitioner claims that the permit does not include periodic monitoring sufficient to assure compliance with the hydrochloride (HCl) limits contained in Condition 7.8.5(a) of the permit. The petitioner states that it is unclear why the USS permit provides for an alternative testing schedule in Condition 7.8.8(a)(iii), which requires HCl performance testing "either annually or according to an alternative schedule that is approved by the applicable permitting authority, but no less frequently than every 2 ½ years or twice per Title V permit term." Petition at 27. Petitioner asserts that, if the permitting authority approved an alternate testing schedule, as allowed by Condition 7.8.8(a)(iii), the public would not know what testing frequency was required. *Id.* Petitioner concludes that the permit must be revised to require HCl performance testing on at least an annual basis. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that "Changes have been made. Condition 7.8.8(1) and (b) of the final CAAPP adopts a 2.5 year interval between the tests required by 40 CFR 63.1161 and 63.1162. This schedule is in line with an option established by 63.1162(a)(1). The IEPA retains the rights to request more frequent tests, if needed." Responsiveness Summary at 39. Although IEPA refers to the underlying applicable requirement option, it did not provide an analysis to demonstrate how the new time interval is adequate to assure compliance with the HCl limit, nor explain why the monitoring is sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. Therefore, I grant the petition on this issue.

I.1. Boilers - PM_{10} Emission Limit

Petitioner's Allegation:

Petitioner claims the permit does not include periodic monitoring sufficient to assure compliance with the PM_{10} emission limit for the boilers in Condition 7.10.3(b)(ii). Petition at 27. Petitioner states that the emission limit must be met on a continuous basis but that the permit only requires performance testing once every five years. Petitioner argues this one-time test does not constitute periodic monitoring and is not sufficient to assure compliance. Petitioner argues the permit must be revised to require additional periodic monitoring, such as the use of a PM CEMS. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states: "This regulation [40 C.F.R. § 63.1162] will never become applicable because the boilers are only allowed to burn gaseous fuels .... This was done to limit the requirements associated with case-by-case determination." IEPA's response did not provide an analysis demonstrating how performance testing once every five years is sufficient to assure compliance with a limit that applies on a continuous basis. IEPA also states that the boilers will only be allowed to burn gaseous fuels. The intent of this sentence is unclear. It appears IEPA is asserting that burning of gaseous fuels only will result in PM_{10} emissions that are below the limit, but IEPA has not provided any support for such a conclusion. It is also unclear why IEPA believes 40 C.F.R. § 63.1162 is not applicable if the boilers are limited to burning gaseous fuel. Therefore, I grant the petition on this issue.

Petitioner also concludes that CEMS be considered the means to comply with the periodic monitoring requirements of part 70. Although CEMS may be the preferred type of monitoring in some instances, they are not always necessary to assure compliance with applicable requirements. Section 504(b) of the Act, 42 U.S.C. § 7661c(b), provides that "continuous emissions monitoring need not be required if alternative methods are available that provide sufficiently reliable and timely information for determining compliance." 42 U.S.C. § 7661c(b). *See also, In the Matter of Alliant Energy WPL - Edgewater Generating Station*, Petition Number V -2009-02 at 11 (August 17, 2010). Petitioner has neither identified an applicable requirement that compels the use of CEMS nor demonstrated that a CEM is the only monitoring method that can assure compliance with the applicable requirements. I am ordering IEPA either to explain how the USS permit provides adequate monitoring or to modify the permit to ensure that it contains monitoring sufficient to assure compliance with the applicable requirements. Therefore, I deny the claim in the petition seeking an order that IEPA must require the use of CEMS in the USS CAAPP permit.

I.2 Boilers - CO Emission Limit

Petitioner's Allegation:

Petitioner claims the permit lacks periodic monitoring sufficient to assure compliance with the CO emission limit for the affected boilers in Condition 7.10.3(e). Petition at 27. Petitioner claims IEPA has not provided a clear rationale supporting the monitoring requirements associated with the limit. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA refers to a "case-by-case determination permit that requires a CO CEMS and some testing as well." Responsiveness Summary at 40. The permit to which IEPA refers is a permit which it is preparing pursuant to section112(g) of the Act, 42 U.S.C. § 7412(g). However, IEPA has yet to issue this permit; therefore, the terms of the permit are not effective. It does not appear that IEPA has included any of the terms of this draft section 112(g) permit in the CAAPP permit. I grant the petition on this issue. IEPA must explain what monitoring is required by the CAAPP permit, and how the monitoring required by the permit is sufficient to assure compliance with the permit condition or yields reliable data from the relevant time period that are representative of the source's compliance with the permit.

J. Internal Combustion Engines

Petitioner's Allegation:

Petitioner claims that the permit requires USS to demonstrate compliance with Condition 7.11.7(b) for PM, CO, NO_x, and SO_2 emission limits for the emergency generator through the use of emergency generator operation records and emission factors identified in the permit. Petition at 28. Petitioner notes the USS permit indicates the emission factors were established in permit 000600003, but that neither of the permits, nor the Responsiveness Summary, identifies the source of the emission factors. Petitioner argues that the use of emission factors from unknown sources cannot be assumed to assure compliance with emission limits. Petitioner asserts that IEPA must provide additional information to justify the monitoring requirements. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA states that the permit "requires a stack testing of emergency generator if the total operation exceeds 500 hr/yr .... Under normal/actual operation scenario, this emergency generator is used only several hours per day." Responsiveness Summary at 41. IEPA failed to address Petitioner's comment that the limits in permit 000600003, and compliance with those limits, were based on emission factors of unknown origin. IEPA has also not explained how the monitoring requirements in the permit are sufficient to assure compliance with the limits. Although IEPA stated in its response that stack testing is required if operation exceeds 500 hours in a year, it is not clear how this testing is sufficient to assure compliance with the limits. Condition 7.11.7(a) limits the operation of the emergency generator to 500 hours per year. Therefore, the stack testing to which IEPA refers is only applicable if the source exceeds its operational limit. I grant on this issue and order IEPA to provide an adequate explanation of whether the monitoring in the permit, including the use of emission factors, is sufficient to assure compliance with the CO emission limit.

K. Gasoline Storage and Dispensing

Petitioner's Allegation:

Petitioner claims that the permit fails to include adequate periodic monitoring to assure compliance with the hourly discharge limit on organic material into the atmosphere in Condition 7.12.3(b)(ii). Petition at 28. Petitioner argues that IEPA has failed to adequately justify how the use of the TANKS program and monthly throughput information is sufficient to assure compliance with an hourly discharge limit. *Id.* Petitioner further asserts that monthly gasoline throughput records do not appear to constitute "reliable data from the relevant time period that are representative of the source's compliance with the permit." *Id.* Petitioner concludes that IEPA must provide additional information to justify the monitoring requirements associated with this condition. *Id.*

EPA Response:

In its Responsiveness Summary, IEPA stated that no changes were made because "compliance . . . is achieved by using TANKS program and monthly gasoline throughput, considering that station [is] in service for 24 hours/day. Recordkeeping requirements of Condition 7.12.9 and compliance procedures of Condition 7.12.12 are sufficient to meet monitoring requirements." IEPA's response merely restates the monitoring requirements in the permit, but does not provide an analysis to demonstrate how the TANKS program and information on monthly gasoline throughput is adequate to assure compliance with the hourly discharge limit, or why these requirements are sufficient to yield reliable data from the relevant time period that is representative of compliance with the permit in either its Project Summary or its responses to Petitioner's comments. Therefore, I grant the petition on this issue.

III. The Permit Lacks Compliance Schedules to Remedy All Current Violations

Petitioner's Allegations:

Petitioner raises two issues with regards to compliance schedules, alleging that a) the permit forgoes a required enforceable compliance schedule in favor of an unacceptable "under review" compliance provision, and b) there are 21 additional instances of current noncompliance given by two notices of violations (NOVs), one given in January 2009 and the other in March 2009. Petition at 28. These are discussed in more detail below.

A. Compliance Schedule

Petitioner's Allegations:

Petitioner states that IEPA and USS entered into a consent order in December 2007 that required USS to submit to IEPA a detailed compliance schedule regarding air pollution violations for basic oxygen furnace operations by March 31, 2008, and to implement the schedule by June 30, 2008. Petition at 29, citing Consent Order 05-CH-750, *Illinois ex. rel. Lisa Madigan v. U.S. Steel Corporation, Inc.*, Dec. 18, 2007, Circuit Court, Third Judicial Circuit, Madison County, Illinois. Petitioner alleges that the permit and Responsiveness Summary show that USS had not submitted an approvable schedule at the time of permit issuance. *Id.* Petitioner claims that by issuing a final permit without making an approved compliance schedule available for review, IEPA deprived the public of an opportunity to comment on a critical aspect of the permit. *Id.* at 29-30.

EPA Response:

EPA believes that, because consent decrees (CD) reflect the conclusion of a judicial or administrative process resulting from the enforcement of "applicable requirements" under the Act, all CAA-related requirements in such CDs are appropriately treated as "applicable requirements" and must be included in title V permits, regardless of whether the applicability issues have been resolved in the CD. This view is consistent with: (1) EPA's part 70 regulations, (*see, e.g.*, 40 C.F.R. § 70.5(c)(8) (compliance schedules "shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the source is subject")); (2) statements EPA made at the time these regulations were issued, (*see, e.g.*, 57 Fed. Reg. 32250, 32255 (July 21, 1992) (preamble to the 1992 final part 70 rule) ("[s]ources seeking to obtain or renew a part 70 permit cannot be shielded from enforcement actions alleging violations of any applicable requirements (including orders and consent decrees) that occurred before, or at the time of, permit issuance.")); and (3) EPA's practice implementing title V. *See, e.g.*, *In the Matter of East Kentucky Power Cooperative, Inc. Hugh L. Spurlock Generating Station Maysville, Kentucky*, Petition IV-2006-4 (August 30, 2007), at 17 ("should the proposed consent decree be entered by the court in the related enforcement action, [the State and the source] would need to appropriately respond by incorporating the compliance schedule(s) required by the consent decree into the permit."); *In the Matter of Dynergy Northeast Energy Generation*, Petition No. II-2001- 06, at 29-30 ("conditions from [a] 1987 Consent Decree are applicable requirements that must be included in [the source's] title V permit."); *see also Sierra Club v. EPA*, 557 F.3d 401, 411 (6th Cir. 2008) (noting EPA's view that, once a CD is final, it will be incorporated into the source's title V permit). *See also* EPA's discussion in the *CITGO* at 12-13.

EPA's regulations at 40 C.F.R. § 70.6(c)(3) require that title V permits contain "[a] schedule of compliance consistent with [section] 70.5(c)(8)." In turn, section 70.5(c)(8) requires, among other things, that compliance schedules "shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the source is subject." 40 C.F .R. § 70.5(c)(8)(iii)(C). *CITGO* at 12-13.

In response to this issue, IEPA noted that USS had submitted a revised compliance schedule under the consent order in July 2009 and that this revised document was under review. The terms of the consent order, however, are applicable requirements that are not reflected in the permit. The consent order required USS to implement the terms of the compliance schedule by June 30, 2008. As IEPA explained, though, the compliance schedule was still under review at the time of permit issuance. If a source is not in compliance with an applicable requirement at the time of permit issuance, EPA's regulations require that a title V permit contain a "schedule of compliance consistent with [40 C.F.R.] § 70.5(c)(8)." See 40 C.F.R. § 70.6(c)(3). This schedule of compliance must include "an enforceable sequence of actions with milestones, leading to compliance." See 40 C.F.R. § 70.5(c)(8)(iii)(C). *CITGO* at 12-13. EPA therefore grants the petition on this issue and directs IEPA to issue a permit that assures compliance with the December 18, 2007, consent order.

B. Notices of Violation

Petitioner's Allegations:

Petitioner further references two NOVs issued to USS by IEPA in January and March 2009 after IEPA issued the draft CAAPP permit and Project Summary. *Id.* at 30. Petitioner concludes that, given these allegations of violations, "it is vital that USEPA require IEPA to develop approved, enforceable schedules of remedial measures with milestones leading to compliance...." *Id.*

EPA Response:

The issuance of an NOV, and reference to information contained therein, are generally not, by themselves, sufficient to satisfy the demonstration requirement under section 505(b)(2) of the Act, 42 U.S.C. § 7661d(b)(2). *See, generally, In the Matter of Georgia Power Company, Bowen Steam - Electric Generating Plant, et al,* (January 8, 2007 at 5-9); *In the Matter of East Kentucky Power Cooperative, Inc., Hugh L. Spurlock Generating Station,* Petition No. IV-2006-4 (August 30. 2007) at 13-18. Section 113(a)(1) of the Act, 42 U.S.C. § 7413(a)(1), provides that, "[w]henever, on the basis of any information available to the Administrator, the Administrator finds that any person has violated or is in violation of any requirement or prohibition of an applicable implementation plan or permit, the Administrator shall [issue an NOV]." An NOV is simply one early step in EPA's process of determining whether a violation has, in fact, occurred. This step is commonly followed by additional investigation or discovery, information gathering, and an exchange of views, all of which occur in the context of an enforcement proceeding, and are important means of fact-finding under our system of civil litigation. An NOV is not a final agency action and is not subject to judicial review. It is well recognized that no binding legal consequences flow from an NOV, and an NOV does not have the force or effect of law. *See PacifiCorp* v. *Thomas,* 883 F.2d 661 (9th Cir. 1988); *Absetec*

Constr. Servs. v. EPA, 849 F.2d 765, 768-69 (2nd Cir. 1988); *Union Elec. Co.* v. *EPA,* 593 F.2d 299, 304-06 (8th Cir. 1979); and *West Penn Power Co.* v. *Train,* 522 F.2d 302, 310-11 (3rd Cir. 1975). *See also, Sierra Club* v. *Johnson,* 541 F.3d at 1267; *Sierra Club* v. *EPA,* 557 F.3d at 406-409.

EPA may consider the issuance of an NOV or filing of a complaint as a relevant factor when determining whether the overall information presented by a petitioner - in light of all the factors that may be relevant - demonstrates the applicability or violation of a requirement for title V purposes. Other factors that may be relevant in this determination include the quality of the information; whether the underlying facts are disputable; the types of defenses available to the source; and the nature of any disputed legal questions, all of which EPA would consider within the constraints of the title V process. See *Sierra Club v. EPA*, 557 F.3d at 406-07. If in any particular case these factors are relevant and the petitioner does not present information concerning them, then EPA may find that the petitioner has failed to present sufficient information to demonstrate that a requirement is applicable or has been violated.

Another factor EPA considers is that the Act's enforcement and permitting authorities are complementary and it is reasonable to give full effect to both. See, e.g., *Sierra Club v. EPA*. 557 F.3d at 405-412 (discussing several aspects of the relationship between the enforcement and permitting authorities and processes). The Act provides EPA relatively short time periods in which to review title V permits. Under section 505(b)(1), EPA has only 45 days to review a proposed permit and determine if an objection is necessary. Similarly, under section 505(b)(2), EPA has only 60 days to review a petition seeking an objection and to determine if a petitioner has demonstrated the permit does not comply with the requirements of the Act. Congress deliberately established these short timeframes consistent with its intent that title V permitting be streamlined. The permit process may not allow EPA to fully investigate and analyze contested allegations. In contrast, the Act provides EPA with broad enforcement authority and several tools to resolve issues of compliance. For example, section 114 of the Act authorizes EPA to issue administrative information requests. And the enforcement process can involve significant information gathering through discovery, expert testimony, hearing, and the like.

In evaluating the nature of demonstration burden under section 505(b)(2) of the Act, EPA also considers the potential impact enforcement cases and title V decisions have on one another as illustrated by the following example. EPA could bring a civil judicial enforcement action for violations by a source of an applicable requirement or permit condition. The source and EPA could then be engaged in litigation over the merits of the allegations in EPA's complaint. Should EPA prevail in that enforcement proceeding, or should the source and EPA propose to settle their difference, then the court would enter judgment in the form of an order or consent decree requiring that the source achieve compliance, either pursuant to the terms of a compliance order, or, at a minimum, by a certain date. Separately, in the context of the issuance of a title V permit to the same source, the permitting authority may determine (on its own or as a result of an EPA objection) that the source is not in compliance with the applicable requirement or permit condition that is the subject of the enforcement proceeding, and require in the title V permit that the source achieve compliance pursuant to a schedule of compliance. Under such circumstances the source could challenge the permit, petition EPA for relief, and appeal to the appropriate circuit court. The source and EPA could then find themselves in two separate for a litigating essentially the same issue -- whether an applicable requirement or permit condition was violated and the appropriateness of a compliance schedule -- which risks potentially different and conflicting results.

Considering all these factors, EPA determines that the petition has failed to demonstrate that a compliance schedule is necessary. Petitioner here has only cited to unresolved NOVs issued to USS and has not provided any further information seeking to demonstrate noncompliance. The petition is denied on this issue.

IV. The Permit Unlawfully Exempts Emissions During Startup, Shutdown, and Malfunction

A. Exemptions from MACT Standards During Periods of Startup, Shutdown and Malfunctions Based on EPA's General Duty Standard Are Invalid

Petitioner's Allegations:

Petitioner claims that numerous provisions in the permit unlawfully exempt USS from otherwise-applicable MACT standards during periods of SSM. Petitioner cites to a December 2008 decision by the District of Columbia Court of Appeals, *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008), which vacated specific regulations at 40 C.F.R. § 63.6(f)(1) and (h)(1) that had exempted sources from complying with otherwise-applicable MACT standards. Petitioner argues that the logic of the Court's opinion applies equally to all exemptions from MACT limits during periods of SSM, and is not limited to the specific regulations challenged. Petitioner also cites to a July 22, 2009, letter from Adam Kushner, the director of EPA's Office of Civil Enforcement ("Kushner letter"). Petitioner argues that the Kushner letter supports its broader view of the *Sierra Club* decision, noting that the letter states: "EPA recognizes that the legality of such source category-specific provisions [i.e., an exemption during periods of SSM] may now be called into question." Petition at 31.

Furthermore, Petitioner claims that nine permit terms[6] illegally allow for broad exemptions from permit requirements during periods of SSM and IEPA's response to comments falls short of adequately explaining why these SSM exemptions are legally or factually justified pursuant to 40 C.F.R. § 70.7(a)(5). *Id.* at 32-33.

EPA Response:

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[6] Petitioner refers to the following permit terms:
Condition 7.2.5-4 - coke oven batteries shutdown and malfunction;
Condition 7.3.5 - by-product recovery plant shutdown and malfunction;
Condition 7.4.5-2.b.i - blast furnace process shutdown and malfunction;
Condition 7.4.5-2.c - blast furnace process startup;
Condition 7.5.5-2.b - basic oxygen furnace shutdown and malfunction;
Condition 7.6.5.a - continuous casting operations shutdown and malfunction;
Condition 7.7.5 - slab reheat furnaces startup;
Condition 7.10.3.g - boilers startup; and
Condition 7.10.3.h.i - boilers shutdown and malfunction.

As Petitioner summarizes, in the *Sierra Club* decision, the D.C. Circuit vacated the SSM exemption contained in 40 C.F.R. § 63.6(f)(1) and (h)(1), which were two provisions of EPA's general provisions regarding MACT standards. When incorporated into MACT regulations for specific source categories, these two provisions exempted sources from the requirements to comply with otherwise-applicable MACT standards during periods of SSM. Following the vacatur of 40 C.F.R. § 63.6(f)(1) and (h)(1), sources (nor permitting authorities) could not rely on these provisions as a basis for an exemption during periods of SSM.

As an initial response to this issue, IEPA noted that the mandate in the case (making the decision effective) had not yet been issued and that it was not making any changes to the permit. EPA finds the state's response to be reasonable. EPA agrees that 40 C.F.R. § 63.6(f)(1) and (h)(1) remained in effect until the D.C. Circuit issued the mandate in *Sierra Club*. See Kushner letter at 2. The mandate did not issue until October 16, 2009, and the USS permit was issued on September 3, 2009. Therefore at the time IEPA issued the USS permit, 40 C.F.R. §63.6(f)(1) and (h)(1) were in effect. It was reasonable for IEPA not to take action in response to the court's decision since the mandate had not been issued at the time of permit issuance. Therefore, Petitioner's claim is denied.

However, since the mandate has now been issued, EPA will address the substance of Petitioner's claim. The vacatur of 40 C.F.R. § 63.6(f)(1) and (h)(1) affected only those MACT standards that incorporated those provisions by reference and contained no other regulatory text excusing compliance during SSM events. The Kushner memo contains tables that provided EPA's initial analysis on whether or not specific MACT standards would be affected by the vacatur. In response to Petitioner's comment, it appears IEPA did review specific MACT standards and the tables in the Kushner letter in addressing the permit conditions identified by Petitioner. IEPA determined that only one of the conditions in question would be affected by the mandate. IEPA found that the SSM exemption in 40 C.F.R. part 63, subpart CCC (Steel Pickling) would be affected once the mandate issued. EPA has reviewed the permit conditions raised by Petitioner and concurs with IEPA that 40 C.F.R. part 63, subpart CCC is the only MACT standard to which USS is subject that has been affected following the issuance of the mandate. EPA has granted other issues in the Petition and ordered IEPA to address them. In that process, EPA recommends that IEPA reopen the USS permit and clarify that the SSM exemption is not available under 40 C.F.R. part 63, subpart CCC.

Finally, EPA disagrees with Petitioner's suggestion that the *Sierra Club* decision applies equally to all SSM exemptions in MACT standards. The D.C. Circuit had before it only the specific language of 40 C.F.R. § 63.6(f)(1) and (h)(1), and the decision is limited to those provisions. Thus, only those MACT standards that relied exclusively on 40 C.F.R. § 63.6(f)(1) and (h)(1) to exempt sources from MACT standards during periods of SSM are affected by the vacatur. While EPA acknowledged in the Kushner letter that the legality of SSM exemption provisions had been called into question, EPA continues to believe that SSM exemptions that are not based on 40 C.F.R. § 63.6(f)(1) and (h)(1) remain in effect until they are changed. EPA is in the process of evaluating SSM exemptions in MACT standards on a case-by-case basis and is addressing emissions during period of SSM in each standard.

B. Exemptions During Periods of Startup, Shutdown and Malfunctions Based on State Law Are Also Invalid

Petitioner's Allegations:

Petitioner claims that nine permit terms[7] illegally allow for broad exemptions from permit requirements during periods of SSM and IEPA's response to comments falls short of adequately explaining why these SSM exemptions are legally or factually justified pursuant to 40 C.F.R. §70.7(a)(5). Petition at 32-33.

EPA Response:

The Illinois SIP provision at 35 IAC § 201.262 provides that a permitting authority shall not authorize a permittee to operate in violation of emission limits and standards during startups unless the permittee has affirmatively demonstrated that it has made all reasonable efforts to, among others, minimize excess emissions. The USS permit contains a determination that the source already has made a demonstration that it has made all reasonable efforts to minimize startup emissions, duration of startups and frequency of startups. However, neither the permit nor the permit record (e.g., a statement of basis) provide any information about, or explanation of, how IEPA determined in advance that the permittee met its burden of affirmatively demonstrating that it had complied with the affirmative defense requirements of the permit. EPA is granting the petition and requiring IEPA to explain how it determined in advance that the permittee had met the requirements of the Illinois SIP at 35 IAC § 201.262, or otherwise make appropriate changes to the permit and explain how the permit ensures compliance with the requirement of the SIP. *See In the Matter of Midwest Generation LLC - Joliet Generating Station (Joliet),* Petition Number V-2004-3 (June 24, 2005), at 15.

The Illinois SIP provision at 35 IAC § 201.262 also provides that a permitting authority shall not authorize a permittee to operate in violation of emission limits and standards during malfunctions or breakdowns unless the permittee has submitted proof that continued operation is required to provide essential service, or to prevent risk of injury to personnel or severe damage to equipment. To authorize continued operation of units in violation of applicable standards, IEPA must have received proof that such operation is necessary to provide essential services, or to prevent injury to personnel or severe damage to equipment. The specific proof required in each instance usually will depend on the nature and the cause of the malfunction or breakdown. Thus, a determination that the permittee has met the requirements of 35 IAC § 201.262 to authorize continued operations during malfunction or breakdowns is a case-by-case determination. EPA therefore is granting the petition and requiring IEPA either to explain in the statement of basis how it determined in advance that the permittee had met the requirements of the Illinois SIP at 35 IAC § 201.262, or to specify in the permit that continued operation during malfunction or

[7] Petitioner refers to the following permit terms:
Condition 7.2.5-4 - coke oven batteries shutdown and malfunction;
Condition 7.3.5 - by-product recovery plant shutdown and malfunction;
Condition 7.4.5-2.b.i - blast furnace process shutdown and malfunction;
Condition 7.4.5-2.c - blast furnace process startup;
Condition 7.5.5-2.b - basic oxygen furnace shutdown and malfunction;
Condition 7.6.5.a - continuous casting operations shutdown and malfunction;
Condition 7.7.5 - slab reheat furnaces startup;
Condition 7.10.3.g - boilers startup; and
Condition 7.10.3.h.i - boilers shutdown and malfunction.

breakdown will be authorized on a case-by-case basis if the source meets the SIP criteria. *See Joliet* at 16.

V. The Permit Fails to Include Compliance Assurance Monitoring Requirements

Petitioner's Allegations:

Petitioner claims that the compliance assurance monitoring (CAM) rule requirements found at 40 C.F.R. part 64 apply to USS because USS filed an initial CAAPP application after April 20, 1998. Petition at 33. Petitioner disputes IEPA's statement in the Project Summary that USS submitted its initial CAAPP application prior to April 1998. *Id.* Petitioner claims that National Steel Corporation[8] submitted a CAAPP application for the Granite City Works in March 1996, and IEPA deemed the application complete in May 1996. However, according to Petitioner, IEPA never acted on the May 1996 application. *Id.* Petitioner asserts that, pursuant to the Illinois CAAPP statute, IEPA's failure to act on the 1996 complete permit application within 18 months constituted final agency action on that application. *Id.* Petitioner further alleges that, because IEPA did not act on the 1996 application within the required 18 months of submission, the application cannot be considered the application for the draft USS CAAPP permit that IEPA made available for public comment in 2008. *Id.* at 34. Petitioner notes that, in May 2007, more than 9 years after the trigger date for CAM inclusion, USS submitted a CAAPP permit application to IEPA, which USS designated as the "initial application." *Id.* Petitioner claims that there are substantial differences between the 1996 and 2007 applications and highlights the 11 years between the two application submissions. *Id.* Petitioner asserts that, had IEPA issued a CAAPP permit with a five-year term in response to the 1996 application in a timely manner, USS would have submitted an application for a renewal permit in 2001, 3 years after the date the CAM rules were triggered. *Id.* Finally, Petitioner alleges that IEPA did not adequately respond to its comments on this issue. *Id.* According to Petitioner, IEPA stated in its Responsiveness Summary that the 1996 application "with a number of updates" was "the only one considered" in issuing the permit at issue. *Id.*, quoting Responsiveness Summary at 43, comment 70. Petitioner notes that IEPA further stated in the Responsiveness Summary that "most of the sources that would be subject to CAM are already covered by a MACT standard and therefore CAM would not be applicable…." *Id.* Petitioner asserts that this is untrue, citing to a number of conditions in the permit[9] that, it claims, are subject to CAM. *Id.* at 34-35.

EPA Response:

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[8] USS purchased National Steel Corporation, which was in bankruptcy, in May 2003.

[9] Petitioner refers to the following terms:
Condition 7.3.4.c - coke by-product recovery plant;
Condition 7.6.4.e - continuous casting;
Condition 7.7.4.e - slab reheat furnaces;
Condition 7.8.4.e - finishing operations;
Condition 7.9.4.e - wastewater treatment plant;
Condition 7.10.4.c – boilers; and
Condition 7.11.4.b – engines.

In general, the CAM rules require a title V applicant to submit as part of its application monitoring provisions that satisfy the requirements of 40 C.F.R. § 64.3, which the permitting authority places into the title V permit to assure compliance with applicable requirements. *See* 40 C.F.R. §§ 64.4 and 64.6. CAM applies to initial title V permits if, by April 20, 1998, the application was not yet filed or the permitting authority had not yet determined that the application was complete; if the permit has significant permit revisions; or if there are renewals of existing permits. 40 C.F.R. § 64.5(a).

National Steel submitted an initial title V permit application to IEPA in 1996. IEPA found the application complete and made a draft permit available for public comment, but did not issue a final permit. On May 29, 2007, several years after it had purchased National Steel, USS submitted an application that indicated on the cover page that it was an application for an initial title V permit, but that included only information necessary for IEPA to include conditions from the MACTs to which the Granite City Works had become subject since 1996. IEPA treated the 2007 application as an amendment to the 1996 application, and, therefore, did not do a completeness determination.

Petitioner has not demonstrated that the CAM requirements applied to the USS permit at the time it was issued. The length of time that elapses between the submission of a title V application and permit issuance is not relevant in regards to whether or not CAM applies. 40 C.F.R. § 64.5 requires CAM for sources that, among other things, apply for an initial title V permit after April 20, 1998. USS, as National Steel, applied for an initial title V permit in May of 1996, well before the CAM applicability deadline. USS had an obligation to update its permit application before IEPA noticed the draft title V permit for public comment on October 15, 2008. *See* 40 C.F.R. § 70.5(b). USS updated its application in 2007 with information on MACT requirements. However, the fact that a source becomes subject to a MACT standard does not, by itself, trigger CAM applicability. *See* 40 C.F. R. § 64.2(b)(i). Petitioner has not demonstrated that USS met any of the criteria that trigger CAM applicability.

Petitioner also suggests that 415 ILCS 5/39.5-5(j) prohibits IEPA from acting on a permit application if it has not done so within 18 months of the completeness determination. EPA disagrees with Petitioner's interpretation of the SIP language. 415 ILCS 5/39.5-5(j) provides that

> [IEPA] shall issue or deny the CAAPP permit within 18 months after the date of receipt of the complete CAAPP application….. Where the Agency does not take final action on the permit within the required time period the permit shall not be deemed issued; rather the failure to act shall be treated as a final permit action.

EPA reads this language to say that IEPA can be sued to take action on the languishing permit application, not that the permit is denied because 18 months has elapsed. This is consistent with section 502(b)(7) of the Act, which is intended to ensure against unreasonable delay by permitting authorities. Under section 502(b)(7) of the Act, state programs must provide that a failure to act on a permit application (whether initial or renewal) by the stated deadlines "shall be treated as a final permit action solely for purposes of obtaining judicial review . . . to require that action be taken by the permitting authority." EPA reads 415 ILCS 5/39.5-5(j) as implementing section 502(b)(7) of the Act.

Given the reasons cited above, I deny the petition on this issue. Petitioner has not demonstrated that CAM applied to USS for the purposes of this permit.[10]

VI. Numerous Permit Provisions Lack Practical Enforceability

Petitioner claims that numerous permit provisions lack practical enforceability. Petition at 35. Petitioner asserts that a title V permit must be sufficiently clear and specific to ensure that all applicable requirements contained therein are enforceable as a practical matter. According to Petitioner, to achieve practical enforceability, a title V permit must accurately describe operational requirements and limitations on emissions for a facility, including any alternative processes that the permitting state has selected. *Id.*, citing 40 C.F.R. § 70.6(a)(1)(iii) and (a)(3). Petitioner alleges that many provisions of the permit lack one or more of the conditions necessary for practical enforceability and must be revised. *Id.*

A. The Permit Fails to Appropriately Incorporate Plans by Reference

Petitioner's Allegations:

Petitioner claims that the CAAPP permit does not sufficiently identify the plans or portions of plans that are incorporated into the USS title V permit by reference. *Id.* at 36. Petitioner asserts that IEPA must incorporate clearly and on the face of the permit, rather than in the Responsiveness Summary, the following plans:

1. fugitive particulate matter operating plan;
2. PM10 contingency measure plan;
3. episode action plan;
4. soaking plan; and
5. work practice plan. *Id.* at 36-37.

EPA Response:

In its Responsiveness Summary, IEPA stated that

> IEPA approval is not required for a plan for fugitive PM operating program. The only requirement is for a review of the plan.... Incorporation by reference is the act of including a second document within another document by only mentioning the second document. If done properly, the entire second document became a part of the main

[10] 40 C.F. R. §64.5(c) states: "... if a part 70 or 71 permit is reopened for cause by EPA or the permitting authority pursuant to § 70.7(f)(1)(iii) or (iv), ... the applicable agency may require the submittal of information under this section for those pollutant-specific emissions units that are subject to [Part 64] and that are affected by the permit reopening." This regulation authorizes IEPA to incorporate CAM if it chooses to do so during a permit reopening. See also section 64.5(a)(2).

document. In order for a document to be properly incorporated by reference, there are 3 criteria: 1) document have existed at the time the main document was created; 2) the main document must describe the particular document to be incorporated with enough specificity to be identified; and 3) must clearly identify the intent that the document be incorporated by reference.

However, this differs from how EPA specifies incorporating documents by reference.

EPA has discussed incorporation by reference in several guidance documents and title V orders. *See e.g., White Paper 2*; *In the Matter of Tesoro Refining and Marketing,* Petition No. IX-2004-6 (March 15, 2005)(*Tesoro*), at 9; *In the Matter of Proposed Clean Air Act Title V Operating Permit Issued to Premcor Refining Group, Inc., for Operation of Port Arthur Refinery*, Petition No. VI-2007-2 (February 16, 2007), at 29. Incorporation by reference may be appropriate where the cited requirement is part of the public docket or is otherwise readily available, clear and unambiguous, and currently applicable. *Tesoro* at 9. As EPA explained in *White Paper 2,* it is important to exercise care to balance the use of incorporation by reference with the need to issue permits that are clear and meaningful to all affected parties, including those who must comply with or enforce their conditions. *White Paper* 2 at 34-38. See also *Tesoro* at 8. In order for incorporation by reference to be used in a way that fosters public participation and results in a title V permit that assures compliance with the Act, it is important that: (1) referenced documents be specifically identified; (2) descriptive information such as the title or number of the document and the date of the document be included so that there is no ambiguity as to which version of a document is being referenced; and (3) citations, cross references, and incorporations by reference are detailed enough that the manner in which any referenced material applies to a facility is clear and is not reasonably subject to misinterpretation. *See White Paper* 2 at 37.

Regarding the five plans identified in the petition, IEPA only provided general information in the USS title V permit about what it intended to incorporate by reference. In particular,

1. IEPA incorporated the fugitive particulate matter operating plan into the permit in Condition 5.3.3. The permit requires that the plan contain the minimum provisions identified in 35 IAC 212.310, amended from time-to-time, and submitted to IEPA. Neither the permit nor the SIP requires IEPA's approval of the plan. The permit, however, did not refer to a specific version of the plan nor did it provide sufficient descriptive information about the plan or its requirements.

2. IEPA incorporated the PM10 contingency measure plan into the permit in Condition 5.3.4. The permit requires USS to implement the approved plan upon notification by IEPA. The permit, however, did not refer to a specific version of the plan nor did it provide sufficient descriptive information about the approved plan or its requirements.

3. IEPA incorporated the episode action plan into the permit in Condition 5.3.9, not Condition 5.3.10 as cited in the petition. The permit requires USS maintain a

written episode action plan at the source and on file with IEPA which contains the information specified in 35 IAC 244.144. The permit, however, did not refer to a specific version of the plan nor did it provide sufficient descriptive information about the plan or its requirements.

4. IEPA incorporated the soaking plan into the permit in Condition 7.2.5-1(b)(i). The permit requires that an initial soaking plan be submitted to IEPA for review prior to resumption of operation of the battery based on design information and supplemented as needed with a revised soaking plan. The permit, however, did not refer to a specific version of the plan nor did it provide sufficient descriptive information about the plan or its requirements.

5. IEPA incorporated the work practice plan into the permit in Condition 7.2.5-2. The permit requires that USS maintain a written emission control work practice plan for the affected battery designed to achieve compliance with visible emission limitations for doors, topside port lids, offtake systems, and charging operations under 40 C.F.R. part 63, subpart L. Condition 7.2.5-2 (b) contains the minimum elements of the plan. Conditions 7.2.5-2 (c) and (d) include the requirements for implementing and revising the plan respectively. The permit, however, did not refer to a specific version of the plan nor did it provide sufficient descriptive information about the plan or its requirements.

Without specific identifying information (such as document date) and a sufficient description of the plan and its requirements, it is not possible to tell which version of the plan applies to USS and what requirements USS must meet pursuant to the plan. IEPA's incorporation is ambiguous and leaves room for misinterpretation and misunderstanding about what exactly is required of USS. As noted by *White Paper 2*, this can create difficulties for all parties, including those who enforce the permit. The ambiguous incorporation also greatly hinders meaningful public participation. Therefore, I grant the petition on this issue. If IEPA wants to use incorporation by reference for these plans, EPA recommends it do so consistent with the three principles from *White Paper 2* and the *Tesoro* Order so that there is no ambiguity as to which version of a document is being referenced.

B. Vague Provisions in the Permit Are Not Practically Enforceable

Petitioner's Allegations:

Petitioner claims that permit conditions must contain sufficient detail to ensure that the source and the public clearly understand permit obligations and compliance evaluation procedures. Petition at 37. Petitioner claims that the phrase "demonstrate that all reasonable steps" [11] from Condition 7.7.5(a) and "took all reasonable steps" from Condition 9.10.2.a.iv lacks specificity and therefore are not practically enforceable. *Id.*

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[11] Both the permit and the SIP at 35 IAC § 201.262 require the permittee to "demonstrate that all reasonable *efforts* are made to minimize startup emissions, duration of individual startups and frequency of startups." Although

EPA Response:

In its Responsiveness Summary, IEPA stated that "'Proper working order' and 'Reasonable steps' are direct citations of applicable regulations; no changes were made." Responsiveness Summary at 50. The Illinois SIP at 35 IAC § 201.262 provides that a permitting authority shall not authorize a permittee to operate in violation of emission limits or standards during startups unless the permit applicant "has affirmatively demonstrated that all reasonable efforts have been made to minimize startup emissions, duration of individual startups and frequency of startups." As discussed above, EPA is granting the petition as to permit Condition 7.7.5 and requiring IEPA to explain how it determined in advance that the permittee had met this requirement of the Illinois SIP, or otherwise make appropriate changes to the permit and explain how the permit ensures compliance with the requirement of the SIP.

Condition 7.7.5(a), which is derived from the SIP and is listed as a term or condition of the broad authorization in Condition 7.7.5, provides that "[t]his authorization does not relieve the Permittee from the continuing obligation to demonstrate that all reasonable efforts are made to minimize startup emissions, duration of individual startups and frequency of startups. . . ." Condition 7.7.5(b) provides broad minimum measures, presumably intended to provide some assurance that USS must make reasonable efforts to minimize emissions. It appears that IEPA intended these conditions to support IEPA's advance determination that USS has made the affirmative showing required by the SIP. But IEPA does not explain how these conditions support the broad advance authorization.

Further, in *In the Matter of Midwest Generation, LLC, Fisk Generating Station*, Petition No. V-2004-1 (March 25, 2005) (*Fisk*), EPA noted that for the permit to be practicably enforceable and ensure compliance with this SIP requirement, it must "include the startup procedures in the permit, or include minimum elements of the startup procedures that would 'affirmatively demonstrate that all reasonable efforts have been made to minimize startup emissions, duration of individual startups and frequency of startups.'" *Fisk* at 14. I direct IEPA, in responding to the grant with regard to the broad advance authorization addressed in IV.B. above, to evaluate whether, and ensure that, any permit conditions regarding startup are practicably enforceable.

With respect to Condition 9.10.2.a.iv, this provision is required by section 39.5(7)(k) of the Illinois Environmental Protection Act. Section 39.5(7)(k) is not an applicable requirement as defined at 40 C.F.R. 70.2. EPA notes that section 504(a) of the Act requires, among other things that, each title V permit shall include "enforceable" emissions limitations and standards and other provisions "as are necessary to assure compliance with applicable requirements" of the Act. Petitioner has not demonstrated that Condition 9.10.2.a.iv relates to an applicable requirement, and has not otherwise demonstrated that the condition is not in compliance with the Act.

Petitioner discusses the phrase "demonstrate that all reasonable steps," EPA believes Petitioner's issue is still relevant.

CONCLUSION

For the reasons set forth above and pursuant to Section 505(b)(2) of the Clean Air Act and 40 C.F.R. § 70.8(d), I hereby grant in part and deny in part the petition filed by Robert R. Kuehn on behalf of the American Bottom Conservancy objecting to the title V operating permit issued to the United States Steel Corporation-Granite City Works.

Dated: 1/31/11

Lisa P. Jackson
Administrator

IN RE MISSISSIPPI LIME COMPANY

PSD Appeal No. 11-01

REMAND ORDER

Decided August 9, 2011

Syllabus

Sierra Club asks the Environmental Appeals Board ("Board") to review certain conditions of a Clean Air Act prevention of significant deterioration ("PSD") permit the Illinois Environmental Protection Agency ("IEPA") issued to Mississippi Lime Company ("Mississippi Lime") for construction of a lime manufacturing plant in Prairie du Rocher, Randolph County, Illinois. After the petition was filed, but prior to either IEPA or Mississippi Lime filing a response brief, the Board held a status conference at which the Board suggested that, in light of the decision in *In re Vulcan Construction Materials, LP*, 15 E.A.D. 163 (EAB 2011), IEPA closely examine the record in the present matter and determine whether the record was sufficient to support IEPA's permit determination or whether IEPA should take a voluntary remand to supplement the record. IEPA subsequently filed a status report indicating that after further examination of the record, IEPA believed the record was sufficient to support the permit decision. IEPA and Mississippi Lime proceeded with briefing.

The contentions in the parties' briefs raise issues that fall within two broad categories: (1) IEPA's Best Available Control Technology ("BACT") analyses and permit limits for certain pollutants and (2) IEPA's determination that emissions from the proposed source would not cause or contribute to violations of certain National Ambient Air Quality Standards ("NAAQS"). Resolution of this appeal requires the Board to address two issues concerning IEPA's BACT analyses:

(1) Has Sierra Club demonstrated that IEPA clearly erred in its BACT analysis for startup and shutdown emissions?

(2) Has Sierra Club demonstrated that IEPA clearly erred in establishing the BACT limitations for sulfur dioxide ("SO_2"), nitrogen oxide ("NO_x"), and particulate matter ("PM") where (a) IEPA declined to consider performance test data at other lime kilns and relied on a design fuel with 3.5% sulfur content when establishing the SO_2 BACT limitation and (b) IEPA declined to consider performance test data at other lime kilns and applied safety margins when establishing the BACT limits for NO_x, filterable PM, and particulate matter measured as "PM_{10}"?

This appeal also requires the Board to decide the following two NAAQS issues:

(1) Has Sierra Club demonstrated that IEPA clearly erred in its application of a Significant Impact Level ("SIL") in the culpability analysis of the ambient air quality analysis for the one-hour SO_2 NAAQS?

(2) Has Sierra Club demonstrated that IEPA clearly erred by not establishing an SO_2 emissions limit or an NO_x emissions limit based on one-hour averages to protect the one-hour SO_2 and the one-hour nitrogen dioxide ("NO_2") NAAQS?

Held: The permit is remanded.

(1) IEPA failed to provide sufficient justification for determining BACT for kiln startup and shutdown emissions. IEPA eliminated natural gas as a control option because of the proposed plant site's distance from the existing natural gas pipeline. IEPA's determination that natural gas was "not commercially feasible" lacks support and does not consider the average and incremental cost-effectiveness of natural gas.

(2) IEPA failed to provide sufficient justification for the permit's BACT emissions limitations for SO_2, NO_x, and PM.

(a) IEPA failed to adequately support its determination that a 3.5% sulfur content design fuel, consisting of both coal and petroleum coke, was BACT for SO_2, particularly when IEPA had already concluded that among the technically feasible coals, coal with 3.2% sulfur content was cost effective. In declining to consider the performance test data at existing kilns that Sierra Club had identified, IEPA fundamentally misunderstood that its role as permit issuer requires the agency to investigate and examine recent regulatory determinations.

(b) IEPA's administrative record does not support IEPA's assertions that compliance margins were necessary for the NO_x, filterable PM, and PM_{10} BACT limits due to variations in the effectiveness of the chosen control measures. IEPA explained neither how it derived the numerical values for the margins nor the technical or scientific bases for the margins. The BACT analyses for these pollutants also do not sufficiently assess data from other facilities that might support the proposed compliance margin. IEPA was obligated to conduct a more thorough evaluation of comparable facilities, including those that Sierra Club cited.

(3) IEPA failed to provide sufficient justification for determining that emissions from the proposed source will not cause or contribute to a violation of the one-hour SO_2 NAAQS. Although it was not improper for IEPA to use a SIL in the culpability analysis for the one-hour SO_2 NAAQS, it is unclear from the administrative record what SIL value IEPA used in the culpability analysis. U.S. Environmental Protection Agency ("EPA") guidance provides an interim one-hour SO_2 SIL of 7.85 g/m^3, which is supported in the administrative record as a de minimis concentration, but IEPA did not explain whether or how this SIL was applied. IEPA further failed to identify whether two other values that appear in the administrative record, 7.9 g/m^3 and 10 g/m^3, were applied as the one-hour SO_2 SIL in the culpability analysis. Finally, to the extent that IEPA applied either 7.9 g/m^3 or 10 g/m^3 as the one-hour SO_2 SIL, IEPA did not demonstrate that those values represent de minimis concentrations.

(4) IEPA failed to provide sufficient justification for not establishing SO_2 and NO_x emissions limits based on one-hour averages to protect the one-hour SO_2 and the one-hour NO_2 NAAQS. IEPA's explanations for not including emission limitations for SO_2 and NO_x based on one-hour averages – that the results of other state agencies' models have "overstated impacts to such a degree that they cannot be considered credible" and that the proposed control technology at the proposed plant cannot catastrophically fail – are unsupported and anecdotal at best. In light of the EPA directive to include emission limitations based on one-hour averages, IEPA's unsupported reasoning for not doing so is inadequate.

Before Environmental Appeals Judges Charles J. Sheehan, Kathie A. Stein, and Anna L. Wolgast.

Opinion of the Board by Judge Stein:

I. *STATEMENT OF THE CASE*

Sierra Club asks the Environmental Appeals Board ("Board") to review certain conditions of a Clean Air Act prevention of significant deterioration ("PSD") permit the Illinois Environmental Protection Agency ("IEPA") issued to Mississippi Lime Company ("Mississippi Lime") for construction of a lime manufacturing plant ("Plant") in Prairie du Rocher, Randolph County, Illinois. Petition for Review and Request for Oral Argument (Jan. 26, 2011) ("Petition"). Both IEPA and Mississippi Lime responded that Sierra Club has failed to demonstrate that review is warranted. *See* IEPA Response to Petition for Review (Apr. 29, 2011) ("IEPA Response"); Mississippi Lime's Response to the Petition (May 6, 2011) ("MLC Response").

II. *ISSUES ON APPEAL*

The contentions in the parties' briefs raise issues that fall within two broad categories: (1) IEPA's Best Available Control Technology ("BACT") analyses and permit limits for certain pollutants and (2) IEPA's determination that emissions from the proposed source would not cause or contribute to violations of certain National Ambient Air Quality Standards ("NAAQS"). Resolution of this appeal requires the Board to address two issues concerning IEPA's BACT analyses:

1. Has Sierra Club demonstrated that IEPA clearly erred in its BACT analysis for startup and shutdown emissions?[1]

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[1] It is unclear from the parties' submissions which pollutants are at issue in the startup and shutdown emissions.

2. Has Sierra Club demonstrated that IEPA clearly erred in establishing the BACT limitations for sulfur dioxide ("SO_2"), nitrogen oxide ("NO_x"), and particulate matter ("PM") where (a) IEPA declined to consider performance test data at other lime kilns and relied on a design fuel with 3.5% sulfur content when establishing the SO_2 BACT limitation and (b) IEPA declined to consider performance test data at other lime kilns and applied safety margins when establishing the BACT limits for NO_x, filterable PM, and particulate matter measured as "PM_{10}"?

This appeal also requires the Board to decide the following two NAAQS issues:

1. Has Sierra Club demonstrated that IEPA clearly erred in its application of a Significant Impact Level ("SIL") in the culpability analysis of the ambient air quality analysis for the one-hour SO_2 NAAQS?

2. Has Sierra Club demonstrated that IEPA clearly erred by not establishing an SO_2 emissions limit or an NO_x emissions limit based on one-hour averages to protect the one-hour SO_2 and the one-hour nitrogen dioxide ("NO_2") NAAQS?

III. *SUMMARY OF DECISION*

The Board concludes that Sierra Club has met its burden of establishing that IEPA clearly erred in several aspects of its permit determination. In particular, the Board holds that: (1) IEPA failed to provide sufficient justification for determining BACT for kiln startup and shutdown emissions; (2) IEPA failed to provide sufficient justification for the permit's BACT emissions limitations for SO_2, NO_x, and PM; (3) IEPA failed to provide sufficient justification for determining that emissions from the proposed source will not cause or contribute to a violation of the one-hour SO_2 NAAQS; and (4) IEPA failed to provide sufficient justification for not establishing SO_2 and NO_x emissions limits based on one-hour averages to protect the one-hour SO_2 and the one-hour NO_2 NAAQS.

IV. *STANDARD OF REVIEW*

Under the rules governing this proceeding, a PSD permit ordinarily will not be reviewed unless it is based on a clearly erroneous finding of fact or conclusion of law, or involves an important matter of policy or exercise of discretion that warrants review. *See* 40 C.F.R. § 124.19(a); Consolidated Permit Regulations, 45 Fed. Reg. 33,290, 33,412 (May 19, 1980). The Board analyzes PSD permits against the backdrop of the preamble to section 124.19, which states that the

Board's power of review "should be only sparingly exercised" and that "most permit conditions should be finally determined at the [permit issuer's] level." 45 Fed. Reg. at 33,412; *accord In re Cardinal FG Co.*, 12 E.A.D. 153, 160 (EAB 2005). The petitioner bears the burden of demonstrating that review is warranted, and the petitioner must raise objections to the permit and explain why the permit issuer's previous response to those objections is clearly erroneous or otherwise warrants review. *In re BP Cherry Point*, 12 E.A.D. 209, 217 (EAB 2005); *In re Steel Dynamics, Inc.*, 9 E.A.D. 740, 744 (EAB 2001).

V. *PROCEDURAL AND FACTUAL HISTORY*

On October 27, 2008, Mississippi Lime applied for a PSD permit to construct a lime manufacturing plant in Prairie du Rocher, Randolph County, Illinois. Mississippi Lime proposed to construct two pre-heater rotary lime kilns designed to burn solid fuel (coal and petroleum coke). Permit Section, Bureau of Air, IEPA, *Project Summary for an Application for Construction Permit/PSD Approval from Mississippi Lime Company for a Lime Manufacturing Plant in Prairie Du Rocher, Illinois* 1 (A.R. 34) ("Project Summary"). The kilns are expected to be the principal source of emissions from the Plant. *Id.* These emissions include PM,[2] SO_2, NO_x, and carbon monoxide.

On October 4, 2010, IEPA issued a draft permit for the Plant and sought public review and comment on the draft. Bureau of Air, IEPA, *Responsiveness Summary for the Public Comment Period on the Issuance of a Construction Permit/PSD Approval for Mississippi Lime Company to Construct a Lime Plant in Prairie du Rocher, Illinois* 2 (Dec. 2010) (A.R. 46) ("RTC"). IEPA also held a public hearing on the draft permit on November 19, 2010. *Id.* It issued its final permit determination on December 30, 2010, along with the response to comments in a "Responsiveness Summary for the Public Comment Period" ("Responsiveness Summary") document. *See generally* Permit Sec., Div. of Air Pollution Control, IEPA, *Construction Permit/PSD Approval NSPS/NESHAP Source, ID No. 157863AAC* (Dec. 30, 2010) (A.R. 47) ("Permit"); RTC. As stated above, Sierra Club filed its petition on January 26, 2011. IEPA's response to the merits of Sierra Club's petition was initially due on March 15, 2011. IEPA sought and obtained an extension of time, and after an additional adjustment to the briefing

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[2] "Particulate matter is the generic term for a broad class of chemically and physically diverse substances that exist as discrete particles (liquid droplets or solids) over a wide range of sizes." National Ambient Air Quality Standards for Particulate Matter, 62 Fed. Reg. 38,652, 38,653 (July 18, 1997). Filterable particulate matter are those particles that can be captured on the filter of a stack test train. 40 C.F.R. pt. 51, subpt. A, app. A. Particulate matter with an aerodynamic diameter of 10 micrometers or less is referred to as "PM_{10}," and particulate matter with an aerodynamic diameter of 2.5 micrometers or less is referred to as "$PM_{2.5}$." *Id.*

schedule, briefing was completed on May 6, 2011.[3]

VI. *ANALYSIS*

The Clean Air Act's PSD program regulates air pollution in areas of the country deemed to be in "attainment" or "unclassifiable" with respect to the NAAQS. *See* Clean Air Act ("CAA") §§ 161, 165, 42 U.S.C. §§ 7471, 7475. NAAQS are "maximum concentration 'ceilings' measured in terms of the total concentration of a pollutant in the atmosphere." Office of Air Quality Planning and Standards, U.S. EPA, *New Source Review Workshop Manual* at C.3 (draft Oct. 1990) ("NSR Manual").[4] Congress charged EPA with developing NAAQS for air pollutants whose presence in the atmosphere in excess of certain concentration levels could "reasonably be anticipated to endanger public health or welfare."[5] CAA § 108(a)(1)(A), 42 U.S.C. § 7408(a)(1)(A); *see* CAA § 109, 42 U.S.C. § 7409. In geographical areas deemed to be in "attainment" for any of these pollutants, the ambient air quality meets the NAAQS for that pollutant. CAA § 107(d)(1)(A)(ii), 42 U.S.C. § 7407(d)(1)(A)(ii). In areas designated as "unclassifiable," air quality cannot be classified on the basis of available information as meeting or not meeting the NAAQS. CAA § 107(d)(1)(A)(iii), 42 U.S.C.

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[3] On March 31, 2011, the Board held a telephone status conference with counsel for Sierra Club, IEPA, and Mississippi Lime. During this status conference, the Board suggested that, in light of the Board's March 2, 2011 decision in *In re Vulcan Construction Materials, LP*, 15 E.A.D. 163 (EAB 2011), IEPA closely examine the record in this matter and determine whether it was sufficient to support IEPA's permit determination or whether IEPA should take a voluntary remand to supplement the record. IEPA indicated that it would examine the record and advise the Board in writing if IEPA planned to continue the briefing process before the Board. Should IEPA choose to proceed with the briefing process before the Board, the Board ordered IEPA's response to the petition to be filed no later than April 29, 2011, and Mississippi Lime's response to be filed no later than May 6, 2011. Order Requiring Status Report & Revising Briefing Schedule (Mar. 31, 2011).

IEPA filed a status report on April 15, 2011, stating that it had "conducted an examination of the record in this matter in order to determine if the record is sufficient to support the [IEPA's] permit determination[; that a] determination ha[d] been reached that the record [wa]s sufficient to support the [IEPA's] permit determination[;]" and that IEPA would file a response to the petition on or before April 29, 2011. State of Illinois Status Report Pursuant to Board Order of March 31, 2011 (Apr. 15, 2011). Accordingly, IEPA filed its response on April 29, 2011, and Mississippi Lime filed its response on May 6, 2011.

[4] The New Source Review or NSR Manual is used as a guide on PSD requirements and policy in new source review workshops and training for state and federal permitting officials. Although it is not a binding U.S. EPA regulation, the Board has looked to the NSR Manual as a statement of U.S. EPA's thinking on certain PSD issues. *E.g.*, *In re ConocoPhillips Co.*, 13 E.A.D. 768, 772 (EAB 2008); *In re RockGen Energy Ctr.*, 8 E.A.D. 536, 542 n.10 (EAB 1999); *In re Knauf Fiber Glass, GmbH ("Knauf I")*, 8 E.A.D. 121, 129 n.13 (EAB 1999).

[5] NAAQS have been established for six criteria pollutants: sulfur dioxide, particulate matter, nitrogen dioxide, carbon monoxide, ozone, and lead. *See* 40 C.F.R. §§ 50.4 – 50.13.

§ 7407(d)(1)(A)(iii).[6] Parties who wish to construct "major emitting facilities"[7] in attainment or unclassifiable areas must obtain preconstruction approval in the form of PSD permits to build such facilities. CAA § 165, 42 U.S.C. § 7475.

As part of the permit issuance process, the PSD regulations at 40 C.F.R. § 52.21 require, among other things, that new major stationary sources of air pollution, and any major modification of such sources, be carefully reviewed prior to construction to ensure that emissions from such facilities will not cause or contribute to an exceedance of the NAAQS or applicable PSD ambient air quality "increments."[8] These permits must also require compliance with emissions limits constituting BACT to minimize emissions of regulated pollutants. CAA § 165(a)(4), 42 U.S.C. § 7475(a)(4); 40 C.F.R. § 52.21(b)(23), (j)(2)-(3).

IEPA administers the PSD program in Illinois pursuant to a delegation of authority from the U.S. Environmental Protection Agency ("EPA"), Region 5 ("Region"). *See* Prevention of Significant Deterioration Delegation of Authority to State Agencies, 46 Fed. Reg. 9580 (Jan. 29, 1981) (setting forth Delegation Agreement between State of Illinois and U.S. EPA); *In re Zion Energy, LLC*, 9 E.A.D. 701, 701 n.1 (EAB 2001). When PSD permits are issued by a state pursuant to a delegation of the federal PSD program, as is the case here, such permits are considered EPA-issued permits and, therefore, are subject to administrative appeal to the Board in accordance with 40 C.F.R. § 124.19.

A. *Sierra Club Has Demonstrated That IEPA Clearly Erred in Its BACT Analysis for Startup and Shutdown Emissions*

New major stationary sources, such as the Plant at issue here, are subject to "best available control technology," or BACT, to minimize emissions of regulated pollutants. CAA § 165(a)(4), 42 U.S.C. § 7375(a)(4); 40 C.F.R. § 52.21(j)(2). The statute defines BACT as follows:

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[6] Areas may also be designated as "nonattainment," meaning that the concentration of a pollutant in the ambient air does not meet the NAAQS for that pollutant. CAA § 107(d)(1)(A)(i), 42 U.S.C. § 7407(d)(1)(A)(i). The PSD program does not apply, however, in nonattainment areas. *See* CAA § 161, 42 U.S.C. § 7471.

[7] A "major emitting facility" is a stationary source in any of certain listed stationary source categories that emits or has the "potential to emit" 100 tons per year ("tpy") or more of any air pollutant, or any other source that has the potential to emit 250 tpy or more of any air pollutant. *See* CAA § 169(1), 42 U.S.C. § 7479(1).

[8] A PSD "increment" refers to "the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for a pollutant." NSR Manual at C.3; *see also* 40 C.F.R. § 52.21(c) (setting forth increments for regulated pollutants).

> The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.

CAA § 169(3), 42 U.S.C. § 7479(3); *accord* 40 C.F.R. § 52.21(b)(12) (similar regulatory definition). As the Board has explained many times, BACT is a "site-specific determination and * * * the combined results of the considerations that form the BACT analysis are the selection of an emission limitation and a control technology that are specific to a particular facility." *In re Three Mountain Power, LLC*, 10 E.A.D. 39, 47 (EAB 2001); *accord In re Christian Cnty. Generation, LLC*, 13 E.A.D. 449, 454 (EAB 2008)*; In re Prairie State Generating Co.*, 13 E.A.D. 1, 12 (EAB 2006), *aff'd sub. nom Sierra Club v. U.S. EPA*, 499 F.3d 653 (7th Cir. 2007); *In re Knauf Fiber Glass, GmbH ("Knauf I")*, 8 E.A.D. 121, 128-29 (EAB 1999).

The NSR Manual guides permit issuers reviewing new sources under the CAA and sets forth a "top-down" process for determining BACT for a particular regulated pollutant.[9] *See* NSR Manual at 1. The NSR Manual summarizes the top-down method for determining BACT as follows:

> [T]he top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent – or "top" – alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or

[9] Although the top-down analysis is not a mandatory methodology, it is frequently used by permitting authorities to ensure that a defensible BACT determination, involving consideration of all requisite statutory and regulatory criteria, is reached. *In re Russell City Energy Ctr., LLC*, 15 E.A.D. 1, 16 n.10 (EAB 2010); *In re N. Mich. Univ*., 14 E.A.D. 283, 292 (EAB 2009); *In re Steel Dynamics*, 9 E.A.D. 165, 183 (EAB 2000); *Knauf I*, 8 E.A.D. at 129 n.14, 134 n.25.

> economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case.

NSR Manual at B.2; *accord Prairie State*, 13 E.A.D. at 13.

The NSR Manual's recommended top-down analysis employs five steps. NSR Manual at B.5-.9; *see also In re Desert Rock Energy Co.*, 14 E.A.D. 484, 522-24 (EAB 2009) (summarizing steps); *Prairie State*, 13 E.A.D. at 13-14 (same). The first step requires the permitting authority to identify all potentially "available" control options. NSR Manual at B.5. Available control options are those technologies, including the application of production processes or innovative technologies, that have "a practical potential for application to the emissions unit and the regulated pollutant under evaluation." *Id.*

Once all possible control options are identified, step 2 allows the elimination of "technically infeasible" options. *Id.* at B.7. This step involves first determining for each technology whether it is "demonstrated," in other words, whether it has been installed and operated successfully elsewhere on a similar facility. *Id.* at B.17. If it has not been demonstrated, the permit issuer then determines whether the technology is both "available" and "applicable." *Id.* at B.17-.22. Technologies identified in step 1 as "potentially" available, but that are neither demonstrated nor found after careful review to be both available and applicable, are eliminated under step 2 from further analysis. *Id.*; *see e.g.*, *Prairie State*, 13 E.A.D. at 34-38 (reviewing step 2 analysis); *Cardinal*, 12 E.A.D. at 163-68 (same); *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 199-202 (EAB 2000) (same).

In step 3, the permit issuer ranks the remaining control options by control effectiveness, with the most effective alternative at the top. NSR Manual at B.7, .22; *see also In re Newmont Nev. Energy Inv., LLC*, 12 E.A.D. 429, 459-64 (EAB 2005) (evaluating challenge to step 3 analysis). In step 4, the permitting authority considers energy, environmental, and economic impacts and either confirms the top alternative as appropriate or determines it to be inappropriate. NSR Manual at B.8-.9, .26-.53. It is in this step that the permit issuer considers issues surrounding the relative cost effectiveness of the alternative technologies. *Id.* at B.31-.46. The permit issuer evaluates the economic impacts by estimating the average and incremental cost-effectiveness of the control technologies, measured in dollars per tons of pollutant emissions removed. *Steel Dynamics*, 9 E.A.D. at 202. The purpose of step 4 is to either validate the suitability of the top control option identified or provide a clear justification as to why that option should not be selected as BACT. NSR Manual at B.26; *see also Prairie State*, 13 E.A.D. at 38-51 (considering the application of step 4); *Three Mountain Power*, 10 E.A.D. at 42 n.3 (evaluating environmental impacts); *Steel Dynamics*, 9 E.A.D. at 202-07, 212-13 (remanding permit because of incomplete cost-effectiveness analysis under step 4).

Ultimately, in step 5, for the pollutant and emission unit under review, the permit issuer selects as BACT the most effective control option that was not eliminated in step 4. NSR Manual at B.9, .53. The reviewing authority should then specify an emission limit for the source that reflects the imposition of the control option selected. *Id.* at B.2, B.54; CAA § 169(3), 42 U.S.C. § 7479(3); *see also Prairie State*, 13 E.A.D. at 14, 51.

In this case, the permit provides that BACT for startup and shutdown of the lime kiln is "auxiliary fuel" defined as distillate fuel oil[10] or natural gas. Permit § 2.1.3-2.c.ii and iii. Sierra Club initially challenged the lack of a BACT analysis for this permit condition. Letter from James P. Gignac, Midwest Director, Sierra Club, to Dean Studer, Hearing Officer, IEPA 11 (Dec. 18, 2010) ("These fuels are lower emitting than coal, but are not equals.") ("Sierra Club Comments"). IEPA explained the following in the Responsiveness Summary:

> The permit appropriately addresses startup and shutdown of the kilns with the requirement to use either diesel fuel or natural gas as an alternative low-sulfur fuels (See Conditions 2.1.3-2(c)(ii) and (c)(iii)). The fact that this comment overlooks is that the plant site currently does not [have] natural gas service nor is it expected to have natural gas service. The permit only provides for the use of natural gas in the event that it would become available. In that case, as observed by the comment, it should be expected that the kilns would use natural gas during start and shutdown because natural gas is less expensive than distillate fuel oil.
>
> The cost of constructing a pipeline to serve the plants, estimated at $1.75 million cannot be considered cost-effective as secondary fuels need only be used during periods of startup and shutdown, when natural scrubbing is absent, and distillate oil, as compared to solid fuel is a low sulfur fuel.

RTC at 25 (footnotes omitted).

In its petition, Sierra Club challenged the adequacy of IEPA's BACT step 4 analysis because it did not consider the relative cost effectiveness of both natural gas and diesel fuel. Pet. at 25. IEPA responded that "[t]he permit only provides for use of natural gas in the event that it would become available." IEPA Response

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[10] In the administrative record and in the parties' briefs, the terms distillate fuel oil and diesel oil are used interchangeably.

at 13; RTC at 25. IEPA does not expressly state that it found natural gas to be a technically infeasible control option; however, IEPA's reason for not conducting a "full blown cost effectiveness analysis" is that "natural gas simply is not available." IEPA Response at 15 ("[IEPA] did consider natural gas but rejected it for the reasons given, it is not available.").[11]

IEPA defends the challenge to the step 4 analysis by arguing that it determined natural gas as "not available." This term is typically associated with the step 2 consideration of whether a control option is technically feasible. Because IEPA does not clearly articulate at which step of the top-down BACT analysis it eliminated natural gas as a control option for startup and shutdown emissions, the Board addresses both IEPA's step 2 and step 4 BACT analyses below.[12]

In arguing that natural gas is not a "commercially feasible" control option because it is not available, IEPA relies on Mississippi Lime's original permit application, which contemplated either natural gas or diesel fuel for kiln startup. Mississippi Lime Company, *Additional Information* 18 (June 11, 2010) ("Mississippi Lime Additional Information") (A.R. 6). The "Additional Information" document Mississippi Lime provided to IEPA explains that the proposed facility location lacks direct natural gas service, and that the estimated cost of "tapping in to the nearest natural gas line and installing all necessary distribution equipment (e.g., piping, regulators, meters, etc.) to service the proposed kilns will cost upward of $1.75 million." *Id.*; IEPA Response at 13. IEPA contends that in these circumstances, natural gas is "not available." IEPA Response at 15.

As noted above, the technical feasibility of control options is evaluated in step 2 of the top-down BACT analysis. A "control technology [that] has been installed and operated successfully on the type of source under review [] is demonstrated and [] is technically feasible." NSR Manual at B.17. An undemonstrated control technology is considered technically feasible if the technology is

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[11] Notably, this explanation – that IEPA "rejected" natural gas as BACT for kiln startup and shutdown because it is "not available" – is at odds with natural gas appearing in the permit as an auxiliary fuel for kiln startup and shutdown. *See* Permit § 2.1.3-2(c)(ii). Additionally, although IEPA argues that "[t]he permit only provides for the use of natural gas in the event that it would become available," IEPA Response at 13, the permit condition does not require the use of natural gas should it become "available," nor does the condition prohibit the use of distillate fuel oil once natural gas is available. Rather, the permit condition merely states: "During startup of a kiln, auxiliary fuel (i.e., distillate fuel oil or natural gas) shall be fired to bring the kiln and its associated control equipment up to the operating temperature before beginning firing of solid fuel." Permit § 2.1.3-2(c)(ii).

[12] The "Additional Information" document Mississippi Lime submitted states that "[t]he BACT analyses for this project follow the procedures outlined in the [NSR Manual]." Mississippi Lime Company, *Additional Information* 17 (June 11, 2010) ("Mississippi Lime Additional Information") (A.R. 6). Because the top-down methodology is the only BACT analysis described in great detail in the NSR Manual, the Board assumes that IEPA's BACT analyses applied the top-down methodology.

both "available" and "applicable." *Id.* "A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development." *Id.* at B.18. Such a technology can be obtained by commercial channels "or is otherwise available within the common sense meaning of the term." *Id.* at B.17. "The question of availability for purposes of BACT is a practical, fact determination, using conventional notions of whether the technology can be put into use." *In re Pennsauken Cnty., N.J.*, 2 E.A.D. 667, 671-72 & n.13 (Adm'r 1988) (citing Webster's New World Dictionary of the American Language 96 (2d College ed. 1972)). An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. "Technologies identified in step one but that are not demonstrated and either not available or not applicable are eliminated under step two from further analysis." *In re Maui Elec. Co.*, 8 E.A.D. 1, 6 (EAB 1998).

The administrative record wholly lacks support for IEPA's assertion that natural gas is not technically feasible. Among other considerations, the Additional Information document plainly states that "*natural gas is a technically feasible fuel for lime kiln firing*, [and] the use of this fuel as BACT was rejected because it is not *commercially* feasible." Mississippi Lime Additional Information at 18 (emphasis added). Moreover, Mississippi Lime's ability to obtain a cost estimate for connecting the proposed facility to a natural gas line and for installing distribution equipment to service the proposed kilns indicates that natural gas is indeed available through commercial channels. *See id.* (estimating cost of "tapping in to the nearest natural gas line and installing all necessary distribution equipment" to exceed $1.75 million). IEPA's attempts to frame the use of natural gas as an "unresolvable technical difficulty" based on the proposed plant site's distance from the existing natural gas pipeline fail to recognize that "where the resolution of technical difficulties is a matter of cost, the applicant should consider the technology as technically feasible." NSR Manual at B.19. Because IEPA's "technical" difficulty is actually merely a matter of cost, IEPA has not shown that natural gas is technically infeasible.

Moreover, IEPA inappropriately considered the cost of physical modifications needed to use natural gas during kiln startup and shutdown as a basis for determining that natural gas as a control technology was technically infeasible under step 2 of the BACT analysis. To the extent that IEPA intended its expression that natural gas was not "commercially feasible" in the Additional Information document to imply the "cost effectiveness" analysis in step 4, the administrative record supporting IEPA's decision falls short in supporting such a determination.

As previously stated, under step 4, the permit issuer considers issues related to the relative cost effectiveness of the alternative control technologies, in addition to their energy and environmental impacts. *Id.* at B.31-.46. The permit issuer evaluates the economic impacts by estimating the average and incremental cost-effectiveness of the control technologies, measured in dollars per tons of pollutant emissions removed. *Steel Dynamics*, 9 E.A.D. at 202. The permit issuer's economic impacts analysis must generally be thorough and detailed. *Id.* at 206; *e.g.*, *In re Inter-Power of N.Y., Inc.*, 5 E.A.D. 130, 149 (EAB 1994) ("Although the absence of [certain] information makes a cost-effectiveness determination more vulnerable to attack[,] we do not find the absence of such data or information fatal in this case, given the extensive information available in the record regarding other recently-permitted coal-fired fluidized boilers."). Nevertheless, in limited circumstances, a full cost analysis is not required. *E.g.*, *Prairie State*, 13 E.A.D. at 35 (eliminating an otherwise technically feasible control alternative at step 2 without undergoing a step 4 cost effectiveness analysis "where control options are * * * redundant") (citing NSR Manual at B.20-.21).

IEPA has not shown that such an exception to conducting a complete cost effectiveness analysis applies in the present case. On this record, IEPA's consideration of natural gas as BACT should have included a step 4 BACT analysis. Instead, the entirety of IEPA's analysis prior to determining natural gas "not commercially feasible" was a single cost estimate for extending natural gas service to the proposed plant. Mississippi Lime Additional Information at 18. This cost estimate failed to consider the average and incremental cost-effectiveness of natural gas. In short, the administrative record does not support IEPA's determination that natural gas for Plant startup and shutdown was "not commercially feasible" within the context of a step 4 analysis.

As the Board has stated, BACT determinations are one of the most critical elements in the PSD permitting process, must reflect the considered judgment on the part of the permit issuer, and must be well documented in the administrative record. *See Desert Rock*, 14 E.A.D. at 520; *Knauf I*, 8 E.A.D. at 132; *accord Newmont*, 12 E.A.D. at 442; *In re Gen. Motors, Inc.*, 10 E.A.D. 360, 363 (EAB 2002). Because the record before the Board is insufficient to support IEPA's BACT determination for startup and shutdown emissions, the permit is remanded on this issue.

On remand, IEPA is ordered to prepare a revised BACT analysis for startup and shutdown emissions and to reopen the public comment period to provide the public with an opportunity to review and comment on that analysis. The BACT analysis shall comply fully with the top-down method and all of its steps, including adequate step 2 and step 4 analyses.[13]

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[13] As previously mentioned, the NSR Manual is not a binding U.S. EPA regulation and, consequently, strict application of the top-down methodology is not mandatory, nor is it the required vehicle for making BACT determinations. *E.g., Russell City*, 15 E.A.D. at 16 n.10; *N. Mich. Univ.*, 14 E.A.D. at 291-92. The Board carefully examines those BACT analyses that deviate from the NSR Manual's methodology to ensure that the permitting agency has set forth a defensible BACT determination that

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B. *Sierra Club Has Demonstrated That IEPA Clearly Erred in Establishing the BACT Limitations for SO_2, NO_X, and Particulate Matter*

Sierra Club makes a multi-part challenge to IEPA's approach in selecting the SO_2, NO_x, and PM BACT emissions limits. First, Sierra Club asserts that IEPA's SO_2 BACT limit is clearly erroneous because there is a discrepancy between the sulfur content in the coal that the revised SO_2 BACT analysis stated was BACT (3.2%) and the sulfur content in the coal that IEPA relied on to determine the SO_2 BACT limit (3.5%). Pet. at 30-32. IEPA clarified that the BACT limit calculations contemplated the use of solid fuel that consisted of both coal *and* petroleum coke, not solely coal. IEPA Response at 22; MLC Response at 5; *see also* Project Summary at 2, 8 n.8. IEPA added that under the BACT limit, the sulfur content of such combined fuel is limited to 3.5%. IEPA Response at 22; MLC Response at 5; *see also* Project Summary at 2, 8 n.8. Second, Sierra Club also claims that IEPA clearly erred in establishing BACT limits for SO_2 by failing to impose lower permit limits based on emissions measurements (sometimes called performance test data) for the pollutant at other lime kiln facilities. Pet. at 26-30.

Additionally, Sierra Club challenges the NO_x and PM BACT limitations based on the same alleged IEPA failure to base the permit limits on emissions measurements for NO_x, filterable PM, and PM_{10} at other lime kiln facilities. *Id.* Sierra Club further disputes IEPA's explanation that application of a "safety margin" is the reason the NO_x, filterable PM, and PM_{10} BACT limits are higher than the emissions rates, and the BACT permit limits, for the other facilities Sierra Club identified. *Id.* These arguments present the following sub-issues for the Board to resolve:

1. Has Sierra Club demonstrated that IEPA clearly erred by declining to consider performance test data at other lime kilns and by relying on a design fuel with 3.5% sulfur content when establishing the SO_2 BACT limitation?

2. Has Sierra Club demonstrated that when establishing the NO_x, filterable PM, and PM_{10} BACT limits, IEPA clearly erred by declining to consider performance test data at other lime kilns and by applying safety margins?

The Board addresses these sub-issues in turn.

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reflects consideration of all relevant statutory and regulatory criteria in the PSD permitting program. *See N. Mich. Univ.*, 14 E.A.D. at 292 n.9, and cases cited.

1. *Sierra Club Has Demonstrated That IEPA Clearly Erred by Declining to Consider Performance Test Data at Other Lime Kilns and by Relying on a Design Fuel with 3.5% Sulfur Content When Establishing the SO_2 BACT Limitation*

In its Project Summary, IEPA stated that the kilns would burn solid fuel in the form of coal and petroleum coke. Project Summary at 2; *see also* Mississippi Lime Additional Information at 25. The Project Summary also stated that BACT for SO_2 emissions was "natural scrubbing," as achieved with the limestone and lime dust produced by the lime kilns and captured by the fabric filters and that "[a]n appropriate SO_2 BACT emission limit with the scrubber is 0.645 lbs SO_2 per ton of lime produced, on a daily or 24-hour average basis." Project Summary at 7. IEPA indicated that the design fuel would have a sulfur content of 3.5%. *Id.* at 8 n.8. IEPA calculated that the kilns, which used ten tons of fuel per hour, would emit 1400 pounds of SO_2 per hour. *Id.* IEPA concluded:

> The controlled SO_2 emissions of the kiln based on a BACT limit of 0.645 pounds per ton of lime would be 32.25 pounds per hour (50 x 0.645 = 32.25). The nominal control efficiency for SO_2 achieved by natural scrubbing would be about 97.5 percent (1-32.25/1400)/100 = .977, 97 percent).

Id.

Sierra Club's comments challenged IEPA's failure to consider lower sulfur coals, in combination with "natural scrubbing," in the SO_2 BACT analysis. Sierra Club Comments at 5. Sierra Club also questioned IEPA's basis for deriving the emissions limit. In particular, Sierra Club commented that the actual SO_2 emissions rate data from a lime kiln in Green Bay, Wisconsin, were 600 times lower than the permitted limit, or "a range of about 0.06 – 0.08 lbs [of SO_2]/ton of lime produced." *Id.* at 8. Sierra Club added that the SO_2 emissions limit for a second kiln in Green Bay was the equivalent of 0.45 lbs/ton of lime produced, also lower than the permit limit for the Mississippi Lime facility.

IEPA recognized that the permit's SO_2 BACT limits were higher than the limits at other lime kilns. RTC at 17. Then, relying on the U.S. EPA's "Compilation of Air Pollutant Emission Factors," or "AP-42," IEPA explained that "this emission data, by itself, is of minimal value for determining BACT in the absence of relevant background information for the tested lime kilns." RTC at 17 (citing Office of Air Quality Planning & Standards, U.S. EPA, *I Compilation of Air Pollutant Emission Factors* (5th ed. Jan. 1995)). Although Sierra Club included the stack test analysis for the Green Bay kiln, which identified the lime quality, the size of the kiln, the production rate, and the test results, Pet. at 27, IEPA responded that Sierra Club's comment "[wa]s of little use in establishing [a] BACT limit unless accompanied by other supporting information. This comment did not include the needed supporting information * * * ." RTC at 18. After dismissing the use of measured SO_2 emissions at other facilities to determine the SO_2 BACT limit for the Mississippi Lime facility, IEPA indicated that it calculated the BACT limit based on the sulfur content of the design fuel. *Id.*

As mentioned earlier, the permit issuer, in step 5 of the BACT analysis, selects the most stringent control alternative found at step 2 to be available and technically feasible that was not eliminated in step 4. In establishing the actual permit limits, the permit issuer sets as BACT an emission limit or limits achievable by the facility using the emissions control alternative it selected rather than imposing a particular pollution control technology. *In re Prairie State Generating Co.*, 13 E.A.D. 1, 51 (EAB 2006), *aff'd sub. nom Sierra Club v. U.S. EPA*, 499 F.3d 653 (7th Cir. 2007); *In re Three Mountain Power, LLC*, 10 E.A.D. 39, 54 (EAB 2001); *see* 40 C.F.R. § 52.21(b)(12) (defining BACT as "an emission limitation").

The NSR Manual recognizes that there are some control techniques with a wide range of performance levels and recommends that, in identifying the performance level for such a control technique, the "most recent regulatory decisions and performance data" should be evaluated. NSR Manual at B.23. Disputes have arisen where evidence in the record establishes a range of emissions rates for the most stringent control alternative and, at step 5 of the top-down analysis, the permit issuer sets the permit's BACT limit at a different rate within the range that otherwise appears appropriate. *Prairie State*, 13 E.A.D. at 51 (citing *In re Cardinal FG Co.*, 12 E.A.D. 153, 169 (EAB 2005); *In re Kendall New Century Dev.*, 11 E.A.D. 40, 52 (EAB 2003); *Three Mountain Power*, 10 E.A.D. at 53; *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 188 (EAB 2000); *In re Knauf Fiber Glass, GmbH ("Knauf II")*, 9 E.A.D. 1, 15 (EAB 2000); *In re Masonite Corp.*, 5 E.A.D. 551, 560-61 (EAB 1994)).

The Board has previously discussed the proper consideration of performance tests in establishing final permit emissions limits. *E.g.*, *In re Newmont Nev. Energy Inv., LLC*, 12 E.A.D. 429, 441-43 (EAB 2005); *Prairie State*, 13 E.A.D. at 54. The Board explained that, for a variety of reasons, the data on past performance may show differences across sources using a given control technique. *E.g.*, *Newmont*, 12 E.A.D. at 441. Several reasons that could explain such variability in measured emissions rates include test method variability, *Knauf II*, 9 E.A.D. at 15, fluctuations in control efficiency, *Masonite*, 5 E.A.D. at 560-61, and "characteristics of individual plant processes," *Knauf I*, 8 E.A.D. at 143. "The underlying principle of all of these cases is that PSD permit limits are not necessarily a direct translation of the lowest emissions rate that has been achieved by a particular technology at another facility, but that those limits must also reflect consideration of any practical difficulties associated with using the control technology." *Cardinal*, 12 E.A.D. at 170.

Thus, the Board has held that the permitting authority is not required to set the emissions limit at the most stringent emissions rate that has been demonstrated by a facility using similar emissions control technology. *Kendall*, 11 E.A.D. at 50-54. Nevertheless, as mentioned above, "the BACT analysis is one of the most critical elements of the PSD permitting process and must, therefore, be well documented in the administrative record." *Newmont*, 12 E.A.D. at 442; *accord Knauf I*, 8 E.A.D. at 131. In particular, "the basis for choosing the alternate level (or range) of control in the BACT analysis must be documented." NSR Manual at B.24. The Board has repeatedly held that the permit issuer must provide a reasoned basis for its decision, which must include an adequate response to comments raised during the public comment period. *E.g., In re Russell City Energy Ctr., LLC*, 15 E.A.D. 1, 59-60 (EAB 2010); *Knauf I*, 8 E.A.D. at 140-42; *In re Gen. Motors, Inc.*, 10 E.A.D. 360, 374 (EAB 2002); *Steel Dynamics*, 9 E.A.D. at 191 n.31; *Masonite*, 5 E.A.D. at 568-69, 572 (remanded due to incomplete BACT analysis); *In re Brooklyn Navy Yard Res. Recovery Facility*, 3 E.A.D. 867, 875 (Adm'r 1992) (remanded for failure to adequately consider public comments regarding BACT).

In this case, IEPA dismissed Sierra Club's suggestion to consider the performance test data at existing kilns due to Sierra Club not providing all the necessary information regarding the emissions from the other kilns without identifying the nature of the missing information. RTC at 17, 18. Then, IEPA stated, "The SO_2 BACT limit was determined based on the level of SO_2 control that would be required to be achieved with the proposed SO_2 control technology." *Id.* at 18. "The level of control was calculated from the sulfur content of the design fuel and the design fuel consumption rate, as was explained in the Project Summary." *Id.* IEPA selected a 3.5% design fuel as the SO_2 BACT because a 3.5% sulfur content "design fuel is the highest sulfur content of fuel at which the lime from the kilns would meet customer specifications for product lime."[14] IEPA Response at 22; RTC at 26.

However, there is no indication that a 3.5% sulfur content design fuel was the most stringent control alternative found at step 2 to be technically feasible that was not eliminated in step 4, particularly when IEPA had already concluded that among the technically feasible coals, coal with 3.2% sulfur content was cost effective.[15] The administrative record is devoid of any analysis of why another de-

[14] "The coal and petroleum coke would be blended to stay within this level." IEPA Response at 22; RTC at 26.

[15] In response to Sierra Club's comments concerning use of a lower sulfur coal, IEPA obtained and provided a cost-effectiveness analysis for alternative low-sulfur solid fuel in the Responsiveness Summary. IEPA explained that in addition to the local high sulfur coal, the new cost-effectiveness analysis considered "two alternative coals, coal from a local reserve of low sulfur coal whose continuing availability is uncertain[,] and Powder [River B]asin coal." RTC at 27. The analysis provided the
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sign fuel with a lower sulfur content was not available and thus, not technically feasible, or not cost-effective. Morever, the Board finds that IEPA fundamentally misunderstands that its role as permit issuer requires the agency to investigate and examine recent regulatory determinations, especially if one is brought to the permit issuer's attention. "[T]he existence of a similar facility with a lower emissions limit creates an obligation for [the permit applicant and permit issuer] to consider and document whether that same emission level can be achieved at [the] proposed facility." *In re Indeck-Elwood, LLC*, 13 E.A.D. 126, 183 (EAB 2006). In the present case, IEPA was obligated to investigate and evaluate other facilities, including the Green Bay kiln that Sierra Club identified.

Additionally, even if IEPA adequately supported its determination that a 3.5% sulfur content design fuel was the BACT, IEPA does not adequately explain how, based on that control technology, IEPA derived the SO_2 BACT limitations. The calculations presented in the project summary appear to demonstrate the efficiency of the control – approximately 97% – based on a 0.645 pounds SO_2 per ton of lime emission rate, *see* Project Summary at 8 n.8, rather than explain how IEPA concluded that a 0.645 pounds SO_2 per ton of lime limitation was BACT.

Accordingly, the permit is remanded on this issue. On remand, IEPA is ordered to prepare a revised BACT analysis for SO_2 and to reopen the public comment period to provide the public with an opportunity to review and comment on this analysis. In conducting this analysis, IEPA should follow and fully comply with the top-down method or another defensible BACT analysis.[16]

2. *Sierra Club Has Demonstrated That When Establishing the NO_x, Filterable PM, and PM_{10} BACT Limits, IEPA Clearly Erred by Declining to Consider Performance Test Data at Other Lime Kilns and by Applying Safety Margins*

When Sierra Club faulted IEPA for failure to consider actual NO_x emissions rate data from other kilns and provided actual emissions data from a lime kiln in Green Bay, Wisconsin, RTC at 22; Sierra Club Comments at 10, IEPA tacitly

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following sulfur contents for the various coals: for the local low sulfur coal, 1.4%; for the Powder River Basin coal, 0.6%; and for the local high sulfur coal, 3.2%. *Id.* IEPA's analysis determined the local high sulfur coal with 3.2% sulfur content to be the most cost effective.

[16] As previously mentioned, the NSR Manual is not a binding U.S. EPA regulation and, consequently, strict application of the top-down methodology is not mandatory, nor is it the required vehicle for making BACT determinations. *E.g., Russell City*, 15 E.A.D. at 16 n.10; *In re N. Mich. Univ.*, 14 E.A.D. 283, 291-92 (EAB 2009). Nevertheless, a permit issuer's BACT determination must consider all requisite statutory and regulatory criteria, and the Board will closely scrutinize those BACT analyses that do not follow the methodology set forth in the NSR Manual. *See N. Mich. Univ.*, 14 E.A.D. at 291-92, and cases cited.

acknowledged the discrepancy between the NO_x emissions at the Green Bay plant and the emissions limit for the proposed plant by attributing the discrepancy to "a margin of safety to account for normal variation in the effectiveness of control measures." RTC at 22. IEPA ultimately chose a NO_x BACT limit in the permit that is approximately 20% greater than the emissions rate at the Green Bay kiln and stated that this margin was reasonable in light of the variability in control measures. *Id.* Similarly, when Sierra Club asserted that the PM limits in the permit were higher than the 4.80 lbs/hr limit set for another lime kiln in Wisconsin (known as the Graymont kiln), Sierra Club Comments at 11, IEPA responded that the permit limits were less stringent than the emissions limit for the Wisconsin lime kiln to include a "'margin of safety' to account for normal variation in particulate emissions for a control system."[17] RTC at 24.

As mentioned earlier, the permitting authority is not required to set the emissions limit at the most stringent emissions rate that has been demonstrated by a facility using similar emissions control technology, *Russell City*, 15 E.A.D. at 59, and the permitting authority retains discretion to set BACT levels that "do not necessarily reflect the highest possible control efficiencies but, rather, will allow permittees to achieve compliance on a consistent basis." *Steel Dynamics*, 9 E.A.D. at 188; *accord Three Mountain Power*, 10 E.A.D. at 53. However, consistent with the Board's numerous holdings that the permit issuer must provide a reasoned basis for its permit decision, the decision "to select an alternate level (or range) of control in the BACT analysis must be documented." NSR Manual at B.24.

IEPA's selection of the proper "achievable" emissions limits and IEPA's use of a "safety margin" (also referred to as a "compliance margin" or "safety factor" in Board decisions) for the NO_x, filterable PM, and PM_{10} BACT limits are intertwined. "A challenge to a permitting authority's use of safety factors [] is not easily entertained separate and apart from the permitting authority's analysis of the record evidence pertaining to achievable emissions limits. This is the case because the concept of a 'safety factor' is intended to allow the permitting authority flexibility in setting the permit limits where there is some degree of uncertainty regarding the maximum degree of emissions reduction that is achievable." *Prairie State*, 13 E.A.D. at 55. For this reason, the Board considers these two issues together.

The Board recently addressed the issue of compliance margins or safety factors in detail, explaining:

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[17] IEPA determined the BACT for particulate emissions from the kilns to be fabric filtration or baghouses and set the following limits: a 0.14 lb/ton of lime produced, 3-hour average, for filterable particular matter; 0.18 lb/ton of lime produced, 3-hour average, for PM_{10}; and 0.105 lb/ton of lime produced, 3-hour average, for $PM_{2.5}$. Project Summary at 9; Permit §§ 2.1.3 to 2.b.i.A-C.

> [The Board] ha[s] approved the use of a so-called "safety factor" in the calculation of the permit limit to take into account variability and fluctuation in expected performance of the pollution control methods. *See, e.g.,* [*Knauf II*, 9 E.A.D. at 15 (EAB 2000)] ("There is nothing inherently wrong with setting an emissions limitation that takes into account a reasonable safety factor."). As we noted in [*Masonite*, 5 E.A.D. 551 (EAB 1994)], where the technology's efficiency at controlling pollutant emissions is known to fluctuate, "setting the emissions limitation to reflect the highest control efficiency would make violations of the permit unavoidable." 5 E.A.D. at 560.
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> In essence, [U.S. EPA] guidance and our prior decisions recognize a distinction between, on the one hand, measured "emissions rates," which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the "emissions limitation" determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility's life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the "emissions limitation" that is "achievable" for that pollution control method over the life of the facility.

In re Vulcan Constr. Materials, L.P., 15 E.A.D. 163, 185 (EAB 2011) (quoting *Russell City*, 15 E.A.D. at 58-59 (quoting *Newmont*, 12 E.A.D. at 441-42)).

In determining whether the selection of a compliance or safety margin is appropriate, the Board's analysis is fact- and case-specific. *Russell City*, 15 E.A.D. at 60 (citing *Prairie State*, 13 E.A.D. at 55 (explaining that the "appropriate application of a safety factor in setting an emission limit is inherently fact-specific and unique to the particular circumstances of the selected technology, the context in which it will be applied, and available data regarding achievable emissions limits")). In each case, the Board examines the specific facts and circumstances in order to determine if the record fully supports the compliance or safety margin and reflects the permit issuer's considered judgment.[18] *Id.* at 64-65.

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[18] As this Board stated in *Russell City*:

> The Board has upheld a range of safety factors, compliance factors, and/or safety margins. *E.g.*, *Newmont*, 12 E.A.D. at 459-64 (upholding the permit issuer's limit based on a control efficiency of 66.5%, where

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While a well-supported compliance or safety margin will generally be upheld by this Board, a compliance or safety margin can cross the line from permissible to impermissible where it is "excessively large or is not sufficiently documented and supported." *Id*. Thus, "selection of a reasonable safety factor is not an opportunity for the permittee to argue for, or for the permit issuer to set, a safety factor that is not fully supported by the record, or that does not reflect the exercise of the permit issuer's considered judgment in determining that the emissions limit, including the safety factor, constitutes BACT." *Id.*

In *Russell City*, the Board upheld a compliance margin for the permit's NO_2 startup emissions limits while recognizing that "it could be argued that the compliance margins selected here tend towards the more generous side." *Id*. The Board did so, however, noting that the permit issuer had conducted an extensive BACT analysis, including an analysis of data from several other facilities. *Id*. Upon review of that data, the permit issuer concluded that a compliance margin was needed to ensure that emissions limits could be reasonably achieved over time. *See id.* at 50. Although petitioners in that case cited data from other facilities, such as the Palomar Energy Center in California, with lower NO_2 startup emissions rates, the permit issuer nevertheless determined that a higher limit was appropriate for the Russell City facility. The permit issuer in *Russell City* stated, in part, that:

> [T]he data from [the Palomar Energy Center in California] includes only five available data points for cold starts, which does not generate a great deal of statistical confidence that the maximum seen in this data set is representative of the maximum that can be expected over the entire life of the facility. Moreover, the wide variability in the data that is available highlights the variability in individual startups, underscoring the need to provide a suffi-

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reductions of up to 80 to 90% "can be achieved"); *Kendall*, 11 E.A.D. at 50-54 (upholding permit issuer's selection of 25 ppmvd, even though similar facility has a 20 ppmvd limit); *Steel Dynamics*, 9 E.A.D. at 188 (upholding the permit issuer's decision to use "the most stringent PM limit ever imposed" on similar facilities, 0.0018, rather than the "lowest ever achieved," .0001 grains per standard cubic feet); *Knauf II*, 9 E.A.D. at 15 (upholding permit issuer's use of a 25% safety factor); *Masonite*, 5 E.A.D. at 560-61 (upholding permit issuer's selection of a 95% control efficiency rather than vendor's proposed guarantee of 97%); *In re Pennsauken Cnty, N.J.*, 2 E.A.D. 768, 769-70 (Adm'r 1989) (concluding that 35.7% removal efficiency rate, as opposed to the 50% rate suggested by petitioners, was not clear error).

15 E.A.D. at 64.

> cient compliance margin to allow the facility to be able to comply during all reasonably foreseeable startup scenarios. For both of these reasons, the Air District has concluded that a cold startup limit of 480 pounds of NO_2 is a reasonable BACT limit that is consistent with the startup emissions performance seen at the Palomar facility.

Id. at 50 (quoting permit issuer's "Additional Statement of Basis"). Upon review, the Board concluded that the compliance margin was rational in light of the evidence in the record. As the Board stated:

> [The permit issuer] repeatedly emphasized the wide variability in the facility data, and the record amply supports these statements. The performance data for cold startups at Palomar, for example, ranges from 22 to 375 pounds (or 26 to 435 pounds depending on which air district's calculations is considered), which is a large range. [The permit issuer] also provided several reasons for the wide variability across sources, as noted above. [The permit issuer's] other explanation for its use of a compliance factor for cold startups – that it only had a small number of data points – is consistent with the Board's discussion of the consideration and significance of long-term data in *Newmont*, where the Board explained that "because 'emissions limitation' is applicable for the facility's life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over the long term." 12 E.A.D. at 442.

Id. at 63 (citations omitted). The Board concluded that the use of a compliance factor was well-supported and reflected the considered judgment of the permit issuer.

In contrast, the matter before the Board in the present case does not contain sufficient record support for the use of a compliance margin for emissions of either NO_x, filterable PM, or PM_{10}. Despite Mississippi Lime's claim that "[i]t is clear from the record that the proposed lime kilns with 'natural scrubbing,' start up and cool down cycles, variations in fuel characteristics, and other operational variabilities, are known to have fluctuations in emissions," MLC Response at 2, neither Mississippi Lime nor IEPA have directed the Board to those supporting portions of the administrative record. Unlike *Russell City*, but strikingly similar to *Vulcan*, the BACT analyses in this case do not include any discussion of what an appropriate compliance margin should be and why the margin should be set at a particular level. Indeed, the BACT analyses make no mention of the need for a compliance margin in establishing the permit's PM or NO_x emissions limits. Nor do the analyses sufficiently assess data from other facilities that might support the proposed compliance margin. This is a salient omission, and indeed IEPA was obligated to conduct a more thorough evaluation of comparable facilities, including those Sierra Club cited. In fact, IEPA did not address the data concerning other kilns' emissions until the Responsiveness Summary, and only to summarily reject Sierra Club's contentions. Moreover, IEPA's only justification for the compliance margins in this case is contained in IEPA's Responsiveness Summary. Those responses in the Responsiveness Summary, however, contain only a cursory and unpersuasive explanation for a compliance margin.

Although permit issuers retain discretion to set BACT levels that "do not necessarily reflect the highest possible control efficiencies but, rather, will allow permittees to achieve compliance on a consistent basis," *Newmont*, 12 E.A.D. at 442 (quoting *Steel Dynamics*, 9 E.A.D. at 188), IEPA has not demonstrated that such reasoning is applicable here. *Accord Prairie State*, 13 E.A.D. at 55; *Three Mountain Power*, 10 E.A.D. at 53. In this case, the administrative record reflects only IEPA's conclusory assertions that a margin of compliance is appropriate.

As to the specific pollutants, although IEPA demonstrated that the NO_x BACT limit in the permit is approximately 20% greater than the emission rate at the Green Bay kiln, IEPA does not describe how it determined this particular margin was reasonable.[19] RTC at 22. The first time IEPA addressed a safety margin for the NO_x emissions was in the Responsiveness Summary, in which IEPA stated:

> Considering that BACT limits must be achievable, which necessitates a set with a margin of safety to account for normal variation in the effectiveness of control measures, it is reasonable that is 20 percent higher than emission rates measured during testing of the cited kiln. Moreover, as the proposed kilns would have continuous emissions monitoring systems for NO_x, one could argue that measured emissions of the cited kiln support a limit that is higher than the limit that has been set.

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[19] IEPA's argument that Sierra Club failed to preserve the safety margin issue for appeal, IEPA Response at 20, lacks merit. IEPA's response to Sierra Club's comments regarding IEPA's failure to consider lower BACT limits at other facilities explained that the permit BACT limits were due to safety margins. An explanation that the BACT limits incorporated safety margins was not provided in the permit record prior to the Responsiveness Summary. Thus, the Responsiveness Summary was the first time IEPA mentioned that the BACT limits included safety margins. Accordingly, IEPA's reasoning was not ascertainable before the close of public comment and may be challenged on appeal. 40 C.F.R. §§ 124.13, .19; *see also Prairie State*, 13 E.A.D. at 45 n.41.

Id. (footnote omitted). This justification for the margin of compliance is lacking. IEPA relies on "normal variation in the effectiveness of control measures," yet IEPA neither asserts nor provides support that such variation in the effectiveness of the chosen control measure for NO_x exists or that, even if it did, twenty percent is an appropriate and supportable margin. Moreover, it is unclear how the kiln that Sierra Club identified in its comments became what appears to be the baseline from which IEPA calculated the safety margin.

With respect to particulate matter, IEPA again addressed the safety margins for the first time in the Responsiveness Summary, where IEPA stated:

> Considering the need for a "margin of safety" to account for normal variation in particulate emissions for a control system [that] is properly operated and maintained, the emission rate measured at the Graymont Kiln supports the BACT limits set for particulate emissions of the proposed kilns.

Id. at 24 (footnotes omitted). IEPA further noted, "For an emission unit controlled by a fabric filter it is certainly reasonable that considerations of a safety factor lead to an emission limit that is twice the emission rate measured in any particular test that is representative of proper operation of such unit and associated filter." *Id.* at 24 n.28. IEPA concluded:

> In addition to the usual consideration for the "safety factor" that should be reflected in these limits, another factor is that a limit is being set for total particulate, including both filterable and condensable particulate. This raises uncertainty as to the test method used to measure condensable particulate in that test as compared to revised test method for measurement of condensable particulate recently adopted by USEPA.

Id. at 24 n.29. As with the margin of safety for NO_x emissions, IEPA's responses are conclusory. The administrative record does not support IEPA's assertion that a variation in the effectiveness of the chosen control measure for particulate matter exists, nor is there any explanation of how IEPA derived the numerical value for the margin and whether the assertions IEPA proffers have any technical or scientific basis.

While the Board generally upholds a well-supported compliance or safety margin, the record must contain a sufficient explanation and justification for the permit issuer's determination to include any safety margin as well as sufficient justification for the particular safety margin selected. IEPA's failure to include explanations in its BACT analyses and the conclusory statements in responding to comments on this issue are insufficient. IEPA fails to provide an adequate rationale as to why compliance margins are appropriate in this case. Significantly, even if IEPA had established the need for compliance margins, the record is wholly devoid of explanations for the actual margins. While there may be valid reasons for including compliance margins, IEPA has failed to sufficiently articulate those reasons or to provide the necessary record support. Under these circumstances, as *Russell City* clearly stated could occur, *see Russell City*, 15 E.A.D. at 65, the compliance margins in this case are impermissible. Thus, the limitations cannot be justified as BACT on this record.

The permit is therefore remanded on the BACT limitations for NO_x, filterable PM, and PM_{10}. On remand, IEPA must explain how it derived the BACT limitations for NO_x, filterable PM, and PM_{10}, and demonstrate that the limits constitute BACT. IEPA must also either (1) provide sufficient rationales for including compliance margins, as well as sufficient rationales for the sizes of any such margins, fully consistent with the Board's precedents, or (2) remove the compliance margins from the permit. Should IEPA choose to retain compliance margins, it must reopen the public comment period to provide the public with an opportunity to submit comments.[20]

C. *Sierra Club Has Demonstrated That IEPA's Application of a SIL in the Culpability Analysis of the Ambient Air Quality Analysis for the One-hour SO_2 NAAQS Is Clearly Erroneous*

As stated above, applicants for PSD permits must, among other things, demonstrate, through analysis of the anticipated air quality impacts associated with their proposed facilities, that their facilities' emissions will not cause or contribute to an exceedance of any applicable NAAQS. *See* CAA § 165(a)(3), 42 U.S.C. § 7475(a)(3); 40 C.F.R. § 52.21(k)-(m). Specifically, the statute prohibits the construction of a major emitting facility unless

> the owner or operator of such facility demonstrates * * * that emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of any * * * national ambient air quality standard in any air quality control region * * * .

CAA § 165(a)(3)(b), 42 U.S.C. § 7475(a)(3)(b). The performance of an ambient air quality and source impact analysis, pursuant to the regulatory requirements of

[20] The Board's case law, including *Russell City*, describes the level of analysis and documentation required to support such a determination, including the importance of carefully evaluating multiple sources and data points as well as information such as recent permit limits at other similar facilities.

40 C.F.R. § 52.21(k), (l) and (m), as part of the PSD permit review process, is the central means for preconstruction determination of whether the source will cause or contribute to an exceedance of the NAAQS. *See In re Haw. Elec. Light Co.*, 8 E.A.D. 66, 73 (EAB 1998).

An air quality analysis generally proceeds in stages, beginning with a preliminary analysis that uses modeling to predict air quality impacts based solely on the proposed facility's emissions. NSR Manual at C.24. This preliminary analysis does not take into account existing ambient air quality or emissions from other sources. *Knauf I*, 8 E.A.D. 121, 149 (EAB 1999). The results are used to determine whether a full impact analysis is required.[21] The results of the preliminary analysis are compared to the "significant ambient impact levels" or "significant impact levels" set forth in the NSR Manual. NSR Manual at C.28. If the modeled impacts (predicted emissions) from the proposed facility are less than the SILs for all pollutants at all locations, the permit applicant generally is not required to conduct a full impact analysis. *Id.* at C.24. However, if the modeled impacts from the facility are greater than the SIL for a pollutant at any location, a full impact analysis is recommended for that pollutant. *Id.* at C.25, .52. The full impact analysis considers emissions from the proposed source in addition to the emissions from any existing sources and "background" emissions within the impact area defined during the preliminary analysis.[22] *Id.*

If the full impact analysis predicts NAAQS violations at particular locations and times, a culpability analysis may be conducted to determine the extent to which the proposed facility is predicted to contribute to the identified violations. The modeled emissions increase at the location and time of a predicted NAAQS violation is compared to the SIL. *Id.* at C.52. If such a modeled emissions increase is less than the SIL, the predicted emissions increase is not considered a significant ambient impact, and "the source will not be considered to cause or contribute to the violation * * * . In such a case, the permitting agency, upon verification of the demonstration, may approve the permit." *Id.*

The use of a SIL in ambient air quality analyses is rooted in the de minimis doctrine, which allows an administrative agency to "overlook circumstances that in context may fairly be considered de minimis." *Ala. Power Co. v. Costle*, 636 F.2d 323, 360 (D.C. Cir. 1979) ("It is commonplace, of course, that the law does not concern itself with trifling matters * * * .") (footnotes omitted). The

[21] The preliminary analysis is also used to define the impact area within which a full impact analysis – if conducted – is carried out. NSR Manual at C.24. The impact area includes all locations where the predicted increase in emissions from the proposed source exceeds the SIL. *Id.*

[22] The so-called "background" emissions consist of secondary emissions that arise from residential, commercial and industrial growth that accompanies the new activity at the source. NSR Manual at C.25.

D.C. Circuit specifically recognized that U.S. EPA may exempt de minimis matters from the statutory commands of the Clean Air Act. *Id.* In particular, the *Alabama Power* court acknowledged EPA's discretion to exempt from new source review "some emissions increases on grounds of de minimis or administrative necessity." *Id.* at 400.

U.S. EPA has "long interpreted the phrase 'cause, or contribute to' [in CAA § 165(a)(3)] to refer to significant, or non-de minimis, emission contributions." *In re Prairie State Generating Co.*, 13 E.A.D. 1, 105 (EAB 2006), *aff'd sub. nom Sierra Club v. U.S. EPA*, 499 F.3d 653 (7th Cir. 2007). When U.S. EPA introduced the concept of SILs, U.S. EPA explained that "since the air quality impact of many sources fall off rapidly to insignificant levels, [U.S.] EPA does not intend to analyze the impacts of a source beyond the point where the concentrations from the source fall below certain levels." 1977 Clean Air Act; Prevention of Significant Air Quality Deterioration, 43 Fed. Reg. 26,379, 26,398 (June 19, 1978). Accordingly, the use of a SIL in the culpability analysis for the one-hour SO_2 NAAQS is not improper, and IEPA did not clearly err by using a SIL. *Prairie State*, 13 E.A.D. at 105. However, when applying a SIL in a culpability analysis to conclude that modeled impacts are de minimis, and thus, exempt from regulation, the permitting agency "must follow a rational approach to determine what level of emission is a de minimis amount." *Ala. Power*, 636 F.2d at 405. It is this use of a SIL that is at issue here.

In this case, the administrative record reflects the use of three different one-hour SO_2 SIL values – 10 g/m^3, 7.9 g/m^3, or 7.85 g/m^3 – in the course of determining that the Plant would not cause or contribute to a violation of the one-hour SO_2 NAAQS. Shell Engineering & Associates ("Shell Engineering") conducted Mississippi Lime's air quality analyses to assess the potential effect of the proposed plant on the ambient air quality. Project Summary at 10. Shell Engineering indicated in a modeling supplement for one-hour SO_2 that it performed a preliminary impact analysis, determined the ambient background value of one-hour SO_2, and conducted a full-impact analysis. Shell Engineering & Associates, *Modeling Supplement – One-hour SO_2 Ambient Air Quality Impact Analysis – Prairie du Rocher Lime Plant* 7-9 (July 26, 2010) ("One-Hour SO_2 Modeling Supplement") (A.R. 13) (Pet. Ex. 6 at 17-19). Because the predicted impact of the proposed source and all outside sources exceeded the one-hour SO_2 NAAQS, Shell Engineering conducted a "culpability analysis" to assess whether the proposed project "contributed significantly to the exceedance of the standard at the exact time and location where the exceedance was predicted by modeling." *Id.* at 9 (Pet. Ex. 6 at 19). The culpability analysis "remove[d] from consideration all hours at individual receptors where the lime plant project was predicted to contribute less than 10 g/m^3." *Id.* Thus, according to Shell Engineering's modeling supplement, the culpability threshold, or 1-hour SO_2 SIL, used in the model was 10 g/m^3. *Id.*; *see also* RTC at 30-31.

IEPA explained that "[s]ince there was not yet a SIL developed for the new one-hour SO_2 standard, [IEPA] and [U.S.] EPA Region V recommended to the applicant that the modeling methodology provided by [U.S.] EPA for the new one-hour NO_2 standard be adapted for SO_2. Therefore, the applicant used a screening level of 10 g/m^3 (which corresponds to 4 ppb)." RTC at 30-31 (citing Notice Regarding Modeling for New Hourly NO_2 NAAQS (rev. 2/25/10), http://www.epa.gov/scram001/no2_hourly_NAAQS_aermod_02-25-10.pdf) ("February 2010 NO_2 NAAQS Guidance"). IEPA does not elaborate when or how it and the Region recommended the modeling methodology to Mississippi Lime. The modeling supplement does not explain how Shell Engineering derived the 10 g/m^3 SIL, other than asserting that IEPA and the Region approved of it. One-Hour SO_2 Modeling Supplement at 9 (Pet. Ex. 6 at 19).

The Project Summary that accompanied the draft permit provides a cursory review of the air quality analysis, with most of the information provided in tables. In particular, IEPA explained that it determined the "maximum impact of the proposed lime plant by itself." Project Summary at 10. These results are reflected in Table 1 of the Project Summary and indicate that the proposed Plant's maximum predicted impact on one-hour SO_2 was 11.40 g/m^3, and that the SIL was 7.9 g/m^3, the second of the three different SILs that appear in the administrative record. *Id.* at 11. Table 3 provides the results of the full-impact analysis, but neither the table nor the Project Summary discusses whether a culpability analysis was conducted or a SIL was applied.

As IEPA correctly noted in its Responsiveness Summary, U.S. EPA has not yet promulgated a final one-hour SO_2 SIL. In August 2010, less than a month after Shell Engineering completed its one-hour SO_2 modeling supplement for Mississippi Lime, U.S. EPA established an interim one-hour SO_2 SIL of 3 ppb, or 7.85 g/m^3, that it "intended to use as a screening tool for completing the required air quality analysis for the new one-hour SO_2 NAAQS under the federal PSD program[.]"[23] Memorandum from Anna Marie Wood, Acting Dir., Air Quality

[23] U.S. EPA also made the interim SIL available for states to use when implementing their authorized PSD permitting programs. Memorandum from Anna Marie Wood, Acting Dir., Air Quality Policy Div., Office of Air Quality Planning & Standards, U.S. EPA, to Reg'l Air Div. Dirs., *General Guidance for Implementing the 1-hour SO_2 NAAQS in PSD Permits, Including an Interim 1-hour SO_2 SIL* 5 (Aug. 23, 2010) ("U.S. EPA 1-Hour SO_2 NAAQS Guidance Memo"). U.S. EPA's guidance memorandum stated:

> States may also elect to choose another value that they believe represents a significant air quality impact relative to the 1-hour SO_2 NAAQS. The EPA-recommended interim 1-hour SO_2 SIL is not intended to supersede any interim SIL that any state chooses to rely upon to implement a state PSD program that is part of an approved SIP, or to impose the use of the SIL concept on any state that chooses to implement the PSD program-in particular the ambient air quality analysis-without using a SIL as a

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Policy Div., Office of Air Quality Planning & Standards, U.S. EPA, to Reg'l Air Div. Dirs., *General Guidance for Implementing the 1-hour SO_2 NAAQS in PSD Permits, Including an Interim 1-hour SO_2 SIL* 5 (Aug. 23, 2010) ("U.S. EPA 1-Hour SO_2 NAAQS Guidance Memo"). The memorandum then explained how U.S. EPA derived the interim SIL. Because IEPA issues PSD permits pursuant to the federal program, the interim SIL is applicable to IEPA-issued permits.

Precisely which one-hour SO_2 SIL value that IEPA used for the ambient air quality analyses of the proposed facility is unclear because there are discrepancies between several documents in IEPA's administrative record. Three documents – Shell Engineering's SO_2 modeling supplement, the Project Summary that accompanied the draft permit, and IEPA's Responsiveness Summary – reflect and discuss two different values as the SIL. The administrative record does not explain the apparent discrepancy between the 7.9 g/m^3 SIL documented in the Project Summary and the 10 g/m^3 SIL provided in both the modeling supplement and the Responsiveness Summary. Then in this appeal, IEPA's response brief does not discuss a 7.9 g/m^3 SIL, but acknowledges use of the 10 g/m^3 SIL, IEPA Response at 7 (quoting RTC at 30), and also confusingly references a third SIL, 7.85 g/m^3. *Id.* at 8 (stating that IEPA's audit of the modeling "indicate[s] that exeedances of the one hour NAAQS for SO_2[] do not occur where contributions of SO_2 from [Mississippi Lime's] kilns made a significant impact under the new SO_2 SIL of 7.85 g/m^3") (citing E-mail from Matt Will to Chris Romaine, *Responses to Mississippi Lime Comments Part II* (Dec. 29, 2010) ("Matt Will E-mail") (IEPA Ex. 2)). The sole document in the administrative record that mentions the application of a 7.85 g/m^3 SIL is an e-mail. IEPA does not identify the roles of the e-mail sender and recipient, and the e-mail itself is too vague to conclude that IEPA used a 7.85 g/m^3 SIL in the one-hour SO_2 ambient air analysis or show the results of any analysis using such a SIL.[24]

(continued)

> screening tool. Accordingly, states that implement the PSD program under an EPA-approved SIP may choose to use this interim SIL, another value that may be deemed more appropriate for PSD permitting purposes in the state of concern, or no SIL at all.

Id.

[24] The e-mail states in pertinent part:

> I don't know where the 3 g/m^3 for SO_2 that the Sierra Club cites comes from but 7.85 g/m^3 was for the SIL for SO_2 was set on August 23, 2010, after the modeling for SO_2 had been submitted. The 3 g/m^3 might be confused with the 3 ppb which is equivalent to 7.85 g/m^3. Previous to August 23rd, the SIL had not officially been set for SO_2 and the consultant assumed all receptors were significant in the modeling for SO_2. Audit runs for the culpability analysis for SO_2 indicate that exeedances of the one hour NAAQS for SO_2[] do not occur where the contributions of

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Even if it were clear as to which concentration – 10 g/m^3, 7.9 g/m^3, or 7.85 g/m^3 – IEPA used as the one-hour SO_2 SIL for the culpability analysis, only the 7.85 g/m^3 SIL is supported in the administrative record as a de minimis concentration. EPA 1-Hour SO_2 NAAQS Guidance Memo at 5. Moreover, the sole document mentioning the 7.85 g/m^3 SIL does not explain whether or how this SIL was applied. *See* Matt Will E-mail. The 7.9 g/m^3 SIL appears only once in the administrative record and without any explanation or reference to external documentation, in the Project Summary, Table 1.

As to the 10 g/m^3 SIL, Shell Engineering's 1-Hour SO_2 Modeling Supplement states that "this concentration SIL was approved by IEPA and EPA Region V." 1-Hour SO_2 Modeling Supplement at 9 (Pet. Ex. 6 at 19). However, the modeling supplement does not support this statement, and IEPA has not directed the Board to documentation in the administrative record that reflects this approval. Nevertheless, the Responsiveness Summary further implies that, due to the absence of a SIL for the new one-hour SO_2 standard, IEPA adapted U.S. EPA's recommended modeling methodology for the one-hour NO_2 NAAQS, as provided in a February 25, 2010 guidance document, to derive the one-hour SO_2 SIL of 10 g/m^3, which corresponds to 4 ppb.[25] *See* RTC at 30 (citing February 2010 NO_2 NAAQS Guidance); *see also* IEPA Response at 7. The cited EPA guidance for the one-hour NO_2 standard – the Notice Regarding Modeling for the New Hourly NO_2 NAAQS – does not appear to provide guidance for determining what level of emissions have a de minimis impact on the 1-hour NO_2 NAAQS. Rather, this guidance document provides "procedures for calculating the NO_2 design value for comparison to the 1-hour NAAQS." February 2010 NO_2 NAAQS Guidance.

The administrative record does not illuminate IEPA's claimed application of the reasoning or methodology described in the February 2010 NO_2 NAAQS guidance to derive the 10 g/m^3 one-hour SO_2 SIL. Additionally, IEPA's explanation in the Responsiveness Summary ignores U.S. EPA's subsequent issuance on June 29, 2010, of a more detailed memorandum addressing the one-hour NO_2 NAAQS and actually providing an interim one-hour NO_2 SIL.[26] *See* Stephen D.

(continued)

> SO_2 from the Mississippi Lime kilns make a significant impact under the new SO_2 SIL of 7.85 g/m^3.

Matt Will E-mail at 2.

[25] Shell Engineering completed these analyses prior to U.S. EPA's issuance of the August 23, 2010 one-hour SO_2 NAAQS guidance memorandum and the interim SIL.

[26] U.S. EPA issued the June 29, 2010 1-hour NO_2 NAAQS memorandum several days before Shell Engineering completed the modeling supplement for the one-hour NO_2 ambient air quality impact analysis.

Page, Dir., Office of Air Quality Planning & Standards, U.S. EPA, to Reg'l Air Div. Dirs., *General Guidance for Implementing the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program* (June 29, 2010) ("U.S. EPA 1-hour NO_2 NAAQS Guidance Memo"). This latter document described U.S. EPA's derivation of an interim one-hour NO_2 SIL and explained U.S. EPA's reasons for concluding that the interim one-hour NO_2 SIL was reasonable. The August 23, 2010 memorandum for the one-hour SO_2 NAAQS relied on the June 29, 2010 1-hour NO_2 NAAQS memorandum to derive the interim SO_2 SIL of 3 ppb, or 7.85 g/m^3. U.S. EPA 1-hour SO_2 NAAQS Guidance Memo at 6. Essentially, the 1-hour SO_2 NAAQS memorandum adopted the reasoning that U.S. EPA had used to derive the interim one-hour NO_2 SIL, and the interim one-hour NO_2 SIL (4 ppb) and the interim one-hour SO_2 SIL (3 ppb) are both 4% of the respective NAAQS. *Id.* Accordingly, IEPA has not shown that any of the U.S. EPA guidance documents support the use of a 10g/m^3 one-hour SO_2 SIL.

IEPA's administrative record is unclear as to which SIL the agency applied in its culpability analysis for the one-hour SO_2 NAAQS. In addition to this lack of clarity, to the extent that IEPA employed a 7.9 g/m^3 or 10 g/m^3 one-hour SO_2 SIL, IEPA failed to substantiate the reason for doing so.[27] Accordingly, the permit is remanded on this issue.

D. *Sierra Club Has Demonstrated That IEPA Clearly Erred by Not Establishing an SO_2 Emissions Limit or an NO_x Emissions Limit Based on One-hour Averages to Protect the One-hour SO_2 and the One-hour NO_2 NAAQS*

The permit sets forth the following emission limits for SO_2 and NO_x: 0.645 lbs of SO_2 per ton of lime, daily (24-hour) average (BACT limit); 32.3 lbs of SO_2 per hour, 3-hour average ("short-term" limit); 3.5 lbs of NO_x per ton of lime, daily (24-hour) average (BACT limit); and 175.0 lbs of NO_x, per hour, 3-hour average ("short-term" limit). Permit §§ 2.1.3-2, 2.1.6(a). Sierra Club alleges that these permit conditions for SO_2 and NO_x are not protective of the one-hour NAAQS for either SO_2 or NO_2 because, although the modeling analyses used to demonstrate compliance with the NAAQS incorporated the maximum emission rates for SO_2 and NO_x, the emissions limits in the permit for those pollutants are not based on the aforementioned maximum emission rates. Pet. at 21. In particular, Sierra Club asserts that although IEPA's models "assumed maximum emission rates over a period of a second or an hour," the permit limits are not based on these emission rates and do not protect the one-hour NAAQS. *Id.* In its comments, Sierra Club alleged that "a 3-hour average would allow all of the emis-

[27] The Board does not decide whether it would be permissible to use a one-hour SO_2 SIL other than 7.85 g/m^3 in a culpability analysis.

sions to occur during one hour, effectively tripling the mass emissions rate assumed by Illinois EPA in the modeling." Sierra Club Comments at 12.

U.S. EPA's *Guideline on Air Quality Models*, Appendix W to 40 C.F.R. Part 51, provides recommendations on modeling techniques and guidance for estimating pollutant concentrations in order to assess control strategies and to determine emission limits.[28] Section 10.2.3.1 states, "Emission limits should be based on concentration estimates for the averaging time that results in the most stringent control requirements." 40 C.F.R. pt. 51, app. W, § 10.2.3.1.a. EPA guidance related to the one-hour SO_2 NAAQS further states:

> Because compliance with the new SO_2 NAAQS must be demonstrated on the basis of a 1-hour averaging period, the reviewing authority should ensure that the source's PSD permit defines a maximum allowable hour emission limitation for SO_2, regardless of whether it is derived from the BACT top-down approach or is the result of an air-quality based emissions rate. Hourly limits are important because they are the foundation of the air quality modeling demonstration relative to the 1-hour SO_2 NAAQS.

U.S. EPA 1-Hour SO_2 NAAQS Guidance Memo at 7. Although U.S. EPA's one-hour NO_2 NAAQS guidance is silent on this issue, significant portions of the one-hour SO_2 NAAQS guidance echo the language in the one-hour NO_2 NAAQS guidance. *Compare* U.S. EPA 1-hour SO_2 NAAQS Guidance Memo *with* U.S. EPA 1-hour NO_2 NAAQS Guidance Memo. Accordingly, the Board believes that it is reasonable to infer that U.S. EPA expects "PSD permit[s] [to] define a maximum allowable hour emission limitation" for NO_x to protect the one-hour NO_2 NAAQS.

IEPA's response to Sierra Club's comments and response brief both state that due to the recent promulgation of the one-hour NAAQS for SO_2 and NO_2, the new NAAQS are not addressed in "historic USEPA guidance for PSD modeling." RTC at 32; IEPA Response at 9. IEPA adds:

> The preliminary experience of many state agencies is that the traditional approach to modeling can be overly con-

[28] U.S. EPA originally published its *Guideline on Air Quality Models* in April 1978 and incorporated it by reference into the PSD regulations in June 1978. Revision to the Guideline on Air Quality Models, 70 Fed. Reg. 68,218, 68,218 (Nov. 9, 2005); *see* 40 C.F.R. § 52.21(*l*)(1) (specifying that all estimates of ambient concentrations must be based on applicable air quality models, databases, and other requirements set forth in the *Guideline on Air Quality Models* at part 51, appendix W).

> servative when used with these new standards, providing results that overstate impacts to such a degree that they cannot be considered credible. In particular, the dispersion modeling would assume that three worst case conditions occur simultaneously, maximum background ambient air quality hourly concentrations from a year of monitoring, maximum short-term emission rates from existing sources, and worst-case hourly meteorological conditions for dispersion of emissions. Given these circumstances, it is appropriate to set short-term limits for SO_2 and NO_x on a three hour averaging time to ameliorate for the unrealistic nature of the modeling process as it acts to overstate impacts.

RTC at 32-33; IEPA Response at 9-10. Additionally, IEPA refuted the possibility that the example that Sierra Club provided in its comments could occur:

> [T]he specific circumstances that [Sierra Club's] comment speculates upon, i.e., with "triple emissions" occurring in a single hour, are not possible for the proposed kilns. The SO_2 and NO_x emissions of the kilns are not controlled by natural scrubbing and process measures that cannot catastrophically fail, resulting in a scenario approaching the one postulated in this comment.

RTC at 33. Read in context, IEPA's final sentence in this response appears to have added an additional word, "not," before "controlled," as the Board believes that IEPA intended to rebut Sierra Club's claim and to convey that the proposed control technology "cannot catastrophically fail." Nevertheless, even with this correction, IEPA's response does not provide the necessary foundation for the Board to conclude that IEPA exercised considered judgment in the decision not to establish permit limits for NO_x and SO_2 based on one-hour averages.

IEPA's record for this permit lacks a coherent, well-reasoned explanation of the decision. Even though the U.S. EPA guidance memorandum on the one-hour SO_2 NAAQS was issued after Shell Engineering developed the models used for the ambient air quality analyses, U.S. EPA issued the memorandum prior to the completion of the draft permit, and more importantly, the memorandum was available at the time that IEPA completed its Responsiveness Summary. Yet IEPA does not explain its decision not to follow the clear directive that "the reviewing authority should ensure that the source's PSD permit defines a maximum allowable hour emission limitation for SO_2." U.S. EPA 1-Hour SO_2 NAAQS Guidance Memo at 7. IEPA's explanations for not including emission limitations for SO_2 and NO_x based on one-hour averages – that the results of other state agencies' models have "overstated impacts to such a degree that they cannot be considered credible" and that the proposed control technology at the proposed plant cannot catastrophically fail – are unsupported and anecdotal at best. In light of the express EPA directive to include emission limitations based on one-hour averages, IEPA's unsupported reasoning for not doing so is inadequate.

The permit is therefore remanded on this issue. On remand, IEPA must either include maximum allowable hourly emissions limitations for SO_2 and NO_x and explain how it concluded that the limitations are protective of the respective one-hour NAAQS or provide sufficient rationale for not including such emissions limitations. In either case, IEPA must reopen the public comment period to provide the public with an opportunity to submit comments.

VII. *ORDER*

The Board remands the permit. On remand, IEPA must: (1) Prepare a revised BACT analysis for startup and shutdown emissions, and reopen the public comment period to provide the public with an opportunity to review and comment on this analysis;[29] (2) Prepare a revised BACT analysis for NO_x, filterable PM, and PM_{10} and reopen the public comment period to provide the public with an opportunity to review and comment on this analysis. Among other matters, the BACT analysis shall, at a minimum, include appropriate consideration of performance test data at other lime kilns. IEPA must also either (a) provide sufficient rationales for including compliance margins, as well as sufficient rationales for the sizes of any such margins, fully consistent with the Board's precedents, or (b) remove the compliance margins from the permit; (3) Identify with specificity the one-hour SO_2 SIL, if any, used in the ambient air quality analysis for the one-hour SO_2 standard, and if IEPA used a one-hour SO_2 SIL, explain in detail (including supporting documentation) whether U.S. EPA approved the SIL and the basis for IEPA's conclusions that the SIL would have a de minimus impact on the one-hour SO_2 NAAQS. IEPA must reopen the public comment period to provide the public with an opportunity to submit comments on the air quality analysis and any data pertaining to the SIL; and (4) Either include maximum allowable hourly emissions limitations for SO_2 and NO_x and explain how IEPA concluded that the limitations are protective of the respective one-hour NAAQS or provide sufficient rationale for not including such emissions limitations. In either case, IEPA must reopen the public comment period to provide the public with an opportunity to submit comments.

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[29] Although adherence to the NSR Manual's top-down BACT analysis is not required, permitting authorities often employ it to ensure that they prepare a defensible BACT determination. Should IEPA follow the top-down method that the NSR Manual describes, the BACT analysis shall comply fully with the method and all of its steps and include adequate step 2 and step 4 analyses. Should IEPA employ an alternative method to determine BACT, it must ensure that all regulatory and statutory criteria are considered and appropriately applied. *See Knauf I*, 8 E.A.D. at 130-31 n.14.

After IEPA completes its analyses on remand and issues the final permit decision pursuant to 40 C.F.R. § 124.15(a),[30] anyone dissatisfied with IEPA's decisions must file a petition seeking the Board's review in order to exhaust administrative remedies pursuant to 40 C.F.R. § 124.19(f)(1)(iii). Any such appeal shall be limited to issues IEPA addressed on remand.

So ordered.

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[30] As in *In re Vulcan Constr. Materials, LP*, 15 E.A.D. 163 (EAB 2011), the Board's decision in this case includes a broad remand on significant and foundational issues, including the BACT and air quality analyses, and it will require a reopening of the comment period and reissuance of the permit. Under the facts of this case, where the significant issues to be addressed on remand will necessitate reopening the comment period, IEPA must comply with all applicable standards in effect at the time the permit is issued on remand. *In re Shell Gulf of Mex.*, 15 E.A.D. 103, 150-51 n.76 (EAB 2010); *In re Shell Gulf of Mex.*, OCS Appeal No. 10-01 through 10-04, at 19-25 (EAB Feb. 10, 2011) (Order on Motions for Reconsideration and/or Clarification) ("Shell Clarification Order"). Since U.S. EPA has authority to lawfully exercise, "through an appropriate process, any discretion it has to interpret what 'all applicable standards in effect' means to a particular source being permitted," *Shell Clarification Order* at 24, IEPA should confer with U.S. EPA as to whether U.S. EPA plans to exercise any such discretion that would affect Mississippi Lime.

D R A F T
OCTOBER 1990

New Source Review Workshop Manual

Prevention of Significant Deterioration and Nonattainment Area Permitting

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PREFACE

This document was developed for use in conjunction with new source review workshops and training, and to guide permitting officials in the implementation of the new source review (NSR) program. It is not intended to be an official statement of policy and standards and does not establish binding regulatory requirements; such requirements are contained in the regulations and approved state implementation plans. Rather, the manual is designed to (1) describe in general terms and examples the requirements of the new source regulations and pre-existing policy; and (2) provide suggested methods of meeting these requirements, which are illustrated by examples. Should there be any apparent inconsistency between this manual and the regulations (including any policy decisions made pursuant to those regulations), such regulations and policy shall govern. This document can be used to assist those people who may be unfamiliar with the NSR program (and its implementation) to gain a working understanding of the program.

The focus of this manual is the prevention of significant deterioration (PSD) portion of the NSR program found in the Federal Regulations at 40 CFR 52.21. It does not necessarily describe the specific requirements in those areas where the PSD program is conducted under a state implementation plan (SIP) which has been developed and approved in accordance with 40 CFR 51.166. The reader is cautioned to keep this in mind when using this manual for general program guidance. In most cases, portions of an approved SIP that are different from those described in this manual will be more restrictive. Consequently, it is suggested that the reader also obtain program information from a State or local agency to determine all requirements that may apply in a area.

The examples presented in this manual are presented for illustration purposes only. They are fictitious and are designed to impart a basic understanding of the NSR regulations and requirements.

A number of terms and acronyms used in this manual have specific meanings within the context of the NSR program. Since this manual is intended for use by those persons generally familiar with NSR these terms are used throughout this document, often without definition. To aid users of the document who are unfamiliar with these terms, general definitions of these terms can be found in Appendix A. The specific regulatory definitions for most of the terms can be found in 40 CFR 52.21. Should there be any apparent inconsistency between the definitions contained in Appendix A and the regulatory definitions or requirements found in Part 40 of the Code of Federal Regulations (including any policy decisions made pursuant to those regulations), the regulations and policy decisions shall govern.

MANUAL ORGANIZATION

The manual is organized into three parts. Part I contains five chapters (Chapters A - E) covering the PSD program requirements. Chapter A describes the PSD applicability criteria and process used to determine if a proposed new or modified stationary source is required to obtain a PSD permit. Chapter B discusses the process by which best available control technology (BACT) is determined for new or modified emissions units. Chapter C discusses the PSD air quality analysis used to demonstrate that the proposed construction will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard or PSD increment. Chapter D discusses the PSD additional impacts analyses which assess the impact of air, ground, and water pollution on soils, vegetation, and visibility caused by an increase in emissions at the subject source. Chapter E identifies class I areas, describes the procedures involved in preparing and reviewing a permit application for a proposed source with potential class I area air quality impacts.

Part II of the manual (Chapters F and G) covers the nonattainment area (NAA) permit program requirements for new major sources and major modifications. Chapter F describes the NAA applicability criteria for new or modified stationary sources locating in a nonattainment area. Chapter G provides a basic overview of the NAA preconstruction review requirements.

Part III (Chapters H and I) covers the major source permit itself. Chapter H discusses the elements of an effective and enforceable permit. Chapter I discusses permit drafting.

INTRODUCTION AND OVERVIEW

Major stationary sources of air pollution and major modifications to major stationary sources are required by the Clean Air Act to a obtain an air pollution permit before commencing construction. The process is called new source review (NSR) and is required whether the major source or modification is planned for an area where the national ambient air quality standards (NAAQS) are exceeded (nonattainment areas) or an area where air quality is acceptable (attainment and unclassifiable areas). Permits for sources in attainment areas are referred to as prevention of significant air quality deterioration (PSD) permits; while permits for sources located in nonattainment areas are referred to as NAA permits. The entire program, including both PSD and NAA permit reviews, is referred to as the NSR program.

The PSD and NAA requirements are pollutant specific. For example, a facility may emit many air pollutants, however, depending on the magnitude of the emissions of each pollutant, only one or a few may be subject to the PSD or NAA permit requirements. Also, a source may have to obtain both PSD and NAA permits if the source is in an area where one or more of the pollutants is designated nonattainment.

On August 7, 1977, Congress substantially amended the Clean Air Act and outlined a rather detailed PSD program. On June 19, 1978, EPA revised the PSD regulations to comply with the 1977 Amendments. The June 1978 regulations were challenged in a lengthy judicial review process. As a result of the judicial process on August 7, 1980, EPA extensively revised both the PSD and NAA regulations. Five sets of regulations resulted from those revisions. These regulations and subsequent modifications represent the current NSR regulatory requirements.

The first set of regulations, 40 CFR 51.166, specifies the minimum requirements that a PSD air quality permit program under Part C of the Act must contain in order to warrant approval by EPA as a revision to a State implementation plan (SIP). The second set, 40 CFR 52.21, delineates the federal PSD permit program, which currently applies as part of the SIP, in approximately one third of States that have not submitted a PSD program meeting the requirements of 40 CFR 51.166. In other words, roughly two thirds of the States are implementing their own PSD program which has been approved by EPA as meeting the minimal requirements for such a program, while the remaining States have been delegated the authority to implement the federal PSD program.

The basic goals of the PSD regulations are: (1) to ensure that economic growth will occur in harmony with the preservation of existing clean air resources to prevent the development of any new nonattainment problems; (2) to protect the public health and welfare from any adverse effect which might occur even at air pollution levels better than the national ambient air quality standards (NAAQS); and (3) to preserve, protect, and enhance the air quality in areas of special natural recreational, scenic, or historic value, such as national parks and wilderness areas. The primary provisions of the

PSD regulations require that new major stationary sources and major modifications be carefully reviewed prior to construction to ensure compliance with the NAAQS, the applicable PSD air quality increments, and the requirement to apply the BACT on the project's emissions of air pollutants.

The third set, 40 CFR 51.165(a) and (b), specifies the elements of an approvable State permit program for preconstruction review for nonattainment purposes under Part D of the Act. A major new source or major modification which would locate in an area designated as nonattainment and subject to a NAA permit must meet stringent conditions designed to ensure that the new source's emissions will be controlled to the greatest degree possible; that more than equivalent offsetting emissions reductions ("emission offsets") will be obtained from existing sources; and that there will be progress toward achievement of the NAAQS.

The forth and fifth sets, 40 CFR Part 51, Appendix S (Offset Ruling) and 40 CFR 52.24 (construction moratorium) respectively, can apply in certain circumstances where a nonattainment area SIP has not been fully approved by EPA as meeting the requirements of Part D of the Act.

Briefly, the requirements of the PSD regulations apply to new major stationary sources and major modifications. A "major stationary source" is any source type belonging to a list of 28 source categories which emits or has the potential to emit 100 tons per year or more of any pollutant subject to regulation under the Act, or any other source type which emits or has the potential to emit such pollutants in amounts equal to or greater than 250 tons per year. A stationary source generally includes all pollutant-emitting activities which belong to the same industrial grouping, are located on contiguous or adjacent properties, and are under common control.

A "major modification" is generally a physical change or a change in the method of operation of a major stationary source which would result in a contemporaneous significant net emissions increase in the emissions of any regulated pollutant. In determining if a proposed increase would cause a significant net increase to occur, several detailed calculations must be performed.

If a source or modification thus qualifies as major, its prospective location or existing location must also qualify as a PSD area, in order for PSD review to apply. A PSD area is one formally designated by the state as "attainment" or "unclassifiable" for any pollutant for which a national ambient air quality standard exists.

No source or modification subject to PSD review may be constructed without a permit. To obtain a PSD permit an applicant must:

1. apply the best available control technology (BACT);

A BACT analysis is done on a case-by-case basis, and considers energy, environmental, and economic impacts in determining the maximum degree of reduction achievable for the proposed source or modification. In no event can the determination of BACT result in an emission limitation which would not meet any applicable standard of performance under 40 CFR Parts 60 and 61.

2. conduct an ambient air quality analysis;

Each PSD source or modification must perform an air quality analysis to demonstrate that its new pollutant emissions would not violate either the applicable NAAQS or the applicable PSD increment.

3. analyze impacts to soils, vegetation, and visibility;

An applicant is required to analyze whether its proposed emissions increases would impair visibility, or impact on soils or vegetation. Not only must the applicant look at the direct effect of source emissions on these resources, but it also must consider the impacts from general commercial, residential, industrial, and other growth associated with the proposed source or modification.

4. not adversely impact a Class I area; and

If the reviewing authority receives a PSD permit application for a source that could impact a Class I area, it notifies the Federal Land Manager and the federal official charged with direct responsibility for managing these lands. These officials are responsible for protecting the air quality-related values in Class I areas and for consulting with the reviewing authority to determine whether any proposed construction will adversely affect such values. If the Federal Land Manager demonstrates that emissions from a proposed source or modification would impair air quality-related values, even though the emissions levels would not cause a violation of the allowable air quality increment, the Federal Land Manager may recommend that the reviewing authority deny the permit.

5. undergo adequate public participation by applicant.

Specific public notice requirements and a public comment period are required before the PSD review agency takes final action on a PSD application.

CHAPTER A
PSD APPLICABILITY

I. INTRODUCTION

An applicability determination, as discussed in this section, is the process of determining whether a preconstruction review should be conducted by, and a permit issued to, a proposed new source or a modification of an existing source by the reviewing authority, pursuant to prevention of significant deterioration (PSD) requirements.

There are three basic criteria in determining PSD applicability. The first and primary criterion is whether the proposed project is sufficiently large (in terms of its emissions) to be a "major" stationary source or "major" modification. Source size is defined in terms of "potential to emit," which is its capability at maximum design capacity to emit a pollutant, except as constrained by federally-enforceable conditions (which include the effect of installed air pollution control equipment and restrictions on the hours of operation, or the type or amount of material combusted, stored or processed).

A new source is major if it has the potential to emit any pollutant regulated under the Act in amounts equal to or exceeding specified major source thresholds [100 or 250 tons per year (tpy)] which are predicated on the source's industrial category. A major modification is a physical change or change in the method of operation at an existing major source that causes a significant "net emissions increase" at that source of any pollutant regulated under the Act.

The second criterion for PSD applicability is that a new major source would locate, or the modified source is located, in a PSD area. A PSD area is one formally designated, pursuant to section 107 of the ACT and 40 CFR 81, by a State as "attainment" or "unclassifiable" for any criteria pollutant, i.e., an air pollutant for which a national ambient air quality standard exists.

The third criterion is that the pollutants emitted in, or increased by, "significant" amounts by the project are subject to PSD. A source's location can be attainment or unclassified for some pollutants and simultaneously nonattainment for others. If the project would emit only pollutants for which the area has been designated nonattainment, PSD would not apply.

The purposes of a PSD applicability determination are therefore:

(1) to determine whether a proposed new source is a "major stationary source," or if a proposed modification to an existing source is a "major modification;"

(2) to determine if proposed conditions and restrictions, which will limit emissions from a new source or an existing source that is proposing modification to a level that avoids preconstruction review requirements, are legitimate and federally-enforceable; and

(3) to determine for a major new source or a major modification to an existing source which pollutants are subject to preconstruction review.

In order to perform a satisfactory applicability determination, numerous pieces of information must be compiled and evaluated. Certain information and analyses are common to applicability determinations for both new sources and modified sources; however, there are several major differences. Consequently, two detailed discussions follow in this section: PSD applicability determinations for major new sources and PSD applicability determinations for modifications of existing sources. The common elements will be covered in the discussion of new source applicability. They are the following:

* defining the source;
* determining the source's potential to emit;
* determining which major source threshold the source is subject to; and
* assessing the impact on applicability of the local air quality, i.e., the attainment designation, in conjunction with the pollutants emitted by the source.

II. NEW SOURCE PSD APPLICABILITY DETERMINATIONS

II.A. DEFINITION OF SOURCE

For the purposes of PSD a stationary source is any building, structure, facility, or installation which emits or may emit any air pollutant subject to regulation under the Clean Air Act (the Act). "Building, structure, facility, or installation" means all the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties and are under common ownership or control. An emissions unit is any part of a stationary source that emits or has the potential to emit any pollutant subject to regulation under the Act.

The term "same industrial grouping" refers to the "major groups" identified by two-digit codes in the Standard Industrial Classification (SIC)

Manual, which is published by the Office of Management and Budget. The 1972 edition of the SIC Manual, as amended in 1977, is cited in the current PSD regulations as the basis for classifying sources. Sources not found in that edition or the 1977 supplement may be classified according to the most current edition.

> *For example a chemical complex under common ownership manufactures polyethylene, ethylene dichloride, vinyl chloride, and numerous other chlorinated organic compounds. Each product is made in separate processing equipment with each piece of equipment containing several emission units. All of the operations fall under SIC Major Group 28, "Chemicals and Allied Products;" therefore, the complex and all its associated emissions units constitute one source.*

In most cases, the property boundary and ownership are easily determined. A frequent question, however, particularly at large industrial complexes, is how to deal with multiple emissions units at a single location that do not fall under the same two-digit SIC code. In this situation the source is classified according to the primary activity at the site, which is determined by its principal product (or group of products) produced or distributed, or by the services it renders. Facilities that convey, store, or otherwise assist in the production of the principal product are called <u>support facilities</u>.

> *For example, a coal mining operation may include a coal cleaning plant, which is located at the mine. If the sole purpose of the cleaning plant is to process the coal produced by the mine, then it is considered to be a support facility for the mining operation. If, however, the cleaning plant is collocated with a mine, but accepts more than half of its feedstock from other mines (indicating that the activities of the collocated mine are incidental) then coal cleaning would be the primary activity and the basis for the classification.*
>
> *Another common situation is the collocation of power plants with manufacturing operations. An example would be a silicon wafer and semiconductor manufacturing plant that generates its own steam and electricity with fossil fuel-fired boilers. The boilers would be considered part of the source because the power plant supports the primary activity of the facility.*

An emissions unit serving as a support facility for two or more primary activities (sources) is to be considered part of the primary activity that relies most heavily on its support.

For example, a steam boiler jointly owned and operated by two sources would be included with the source that consumes the most steam.

As a corollary to the examples immediately above, suppose a power plant, is co-owned by the semiconductor plant and a chemical manufacturing plant. The power plant provides 70 percent of its total output (in Btu's per hour) as steam and electricity to the semiconductor plant. It sells only steam to the chemical plant. In the case of co-generation, the support facility should be assigned to a primary activity based on pro rata fuel consumption that is required to produce the energy bought by each of the support facility's customers, since the emission rates in pounds per Btu are different for steam and electricity. In this example then, the power plant would be considered part of the semiconductor plant.

It is important to note that if a new support facility would by itself be a major source based on its source category classification and potential to emit, it would be subject to PSD review even though the primary source, of which it is a part, is not major and therefore exempt from review. The conditions surrounding such a determination is discussed further in the section on major source thresholds (see Section II.C.).

II.B. POTENTIAL TO EMIT

II.B.1. BASIC REQUIREMENTS

The potential to emit of a stationary source is of primary importance in establishing whether a new or modified source is major. Potential to emit is the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, provided the limitation or its effect on emissions is federally-enforceable, shall be treated as part of its design. Example limitations include:

(1) *Requirements to install and operate air pollution control equipment at prescribed efficiencies;*

(2) *Restrictions on design capacity utilization [note that these types of limitations are not explicitly mentioned in the regulations, but in certain instances do meet the criteria for limiting potential to emit];*

(3) *Restrictions on hours of operation; and*

(4) *Restrictions on the types or amount of material processed, combusted or stored.*

II.B.2. ENFORCEABILITY OF LIMITS

For any limit or condition to be a legitimate restriction on potential to emit, that limit or condition must be federally-enforceable, which in turn requires practical enforceability (see Appendix A) [see U.S. v. Louisiana-Pacific Corporation, 682 F. Supp. 1122, Civil Action No. 86-A-1880 (D. Colorado, March 22, 1988). Practical enforceability means the source and/or enforcement authority must be able to show continual compliance (or noncompliance) with each limitation or requirement. In other words, adequate testing, monitoring, and record-keeping procedures must be included either in an applicable federally issued permit, or in the applicable federally approved SIP or the permit issued under same.

For example, a permit that limits actual source emissions on an annual basis only (e.g., the facility is limited solely to 249 tpy) cannot be considered in determining potential to emit. It contains none of the basic requirements and is therefore not capable of ensuring continual compliance, i.e., it is not enforceable as a practical matter.

The term "federally-enforceable" refers to all limitations and conditions which are enforceable by the Administrator, including:

! *requirements developed pursuant to any new source performance standards (NSPS) or national emission standards for hazardous air pollutants (NESHAP),*

- *requirements within any applicable federally-approved State implementation plan, and*

- *any requirements contained in a permit issued pursuant to federal PSD regulations (40 CFR 52.21), or pursuant to PSD or operating permit provisions in a SIP which has been federally approved in accordance with 40 CFR 51 Subpart I.*

Federally-enforceable permit conditions that may be used to limit potential to emit can be expressed in a variety of terms and usually include a combination of two or more of the following four requirements in conjunction with appropriate record-keeping requirements for verification of compliance:

(1) Installation and continuous operation and maintenance of air pollution controls, usually expressed as both a required abatement efficiency of the maximum uncontrolled emission rate and a maximum outlet concentration or hourly emission rate (flow rate x concentration);

A typical example might be a 255 tpy limit on a stone crushing operation. The enforceable permit conditions could be a maximum emission rate of 58 lbs/hr, a maximum concentration of 0.1 grains per dry standard cubic foot (gr/dSCF) and a maximum flow rate of 67,000 dSCFM based on nameplate capacity and 8760 hours per year. In addition, the permit should also stipulate a minimum 90 percent overall reduction of particulate matter (PM) emissions on an hourly basis via capture hoods and a baghouse.

(2) Capacity limitations;

The stone crusher decides to limit its potential to emit to 180 tpy by limiting the feed rate to 70 percent of the nameplate capacity. One of the enforceable limits becomes a stone feed rate (tons/hr.) based on 70 percent of nameplate capacity with a federally-enforceable requirement for a method or device for measuring the feed rate on an hourly basis. Another approach is to limit the PM emissions rate to 41 lbs/hr. A third alternative is to retain a maximum concentration of 0.1 gr./dSCF, but limit the maximum exhaust rate to 47,000 dSCFM due to the decrease in feed rate. In all these cases, the 90 percent overall reduction of particulate matter (PM) emissions on an hourly basis via capture hoods and baghouse would also be maintained.

In another example, the potential to emit of a boiler with a design input capacity of 200 million Btu/hour is limited to a 100-million-Btu/hr fuel input rate by the permit, which *requires that the boiler's heat input not exceed 50 percent of its rated capacity. The permit would further require that compliance be demonstrated with a continuously recording fuel meter and concurrent monitoring and recording of fuel heating value to show that the fuel input does not exceed 100-million-Btu/hr.*

(3) Restrictions on hours of operation, including seasonal operation; and

In the stone crusher example, the operator may choose to limit the hours of operation per year to keep the potential to emit below the major source threshold of 250 tpy. For example, using the same maximum concentration and flow rate and minimum overall control efficiency limitations as in (1) above, a restriction on the number of 8-hour shifts to two, i.e., 16 hours per day would reduce the potential uncontrolled emissions by 33 percent to 170 tpy.

In another example, a citrus dryer that only operates during the growing season could have its potential to emit limited by a permit restriction on the hours of operation, and further, by prohibiting the dryer from operating between March and November.

(4) Limitations on raw materials used (including fuel combusted) and stored.

An example of this type of limit would be a maximum 1 percent sulfur content in the coal feed for a power plant. Another would be a condition that a surface coater only use water-based or higher solids coatings with a maximum VOC content of 2.0 pounds VOC per gallon solids deposited on the substrate with requisite limits on coating usage (gallons/hr or gallons/yr on a 12-month rolling time period).

In addition to limits in major source construction permits or federally approved SIP limits for major sources, terms and conditions contained in State operating permits will be considered federally-enforceable under the following conditions:

(1) the State's operating permit program is approved by EPA and incorporated into the applicable SIP under section 110 of the Act;

(2) the operating permits are legally binding on the source under the SIP and the SIP specifically provides that permits that

are not legally binding may be deemed not "federally-enforceable;"

(3) *all emissions limitations, controls, and other requirements imposed by such permits are no less stringent than any counterpart limitations and requirements in the SIP, or in standards established under sections 111 and 112 of the ACT;*

(4) *the limitations, controls and requirements in the operating permits are permanent, quantifiable, and otherwise enforceable as a practical matter; and*

(5) *the permits are issued subject to public participation, i.e., timely notice, opportunity for public comment, etc.*

(See also, 54 FR 27281, June 28, 1989.)

A minor (i.e., a non-major) source construction permit issued to a source by a State may be used to determine the potential to emit if:

! *the State program under which the permit was issued has been approved by EPA as meeting the requirements of 40 C.F.R. Parts 51.160 through 51.164, and*

! *the provisions of the permit are federally-enforceable and enforceable as a practical matter.*

Note, however, that a permit condition that temporarily restricts production to a level at which the source does not intend to operate for any extensive time is not valid if it appears to be intended to circumvent the preconstruction review requirements for major source by making the source temporarily minor. Such permit limits cannot be used in the determination of potential to emit. Another situation that should receive careful scrutiny is the construction of a manufacturing facility with a physical capacity far greater than the limits specified in a permit condition. See also 54 FR 27280, which specifically discusses "sham" minor source permits.

An example is construction of an electric power generating unit, which is proposed to be operated as a peaking unit but which by its nature can only be economical if it is used as a base-load facility.

Remember, if the permit or SIP requirements, conditions or limits on a source are not federally-enforceable (which includes enforceable as a practical matter), potential to emit is based on full capacity and year-round operation. For additional information on federally enforceability and limiting potential to emit see Appendix A.

II.B.3. FUGITIVE EMISSIONS

As defined in the federal PSD regulations, fugitive emissions are those "...which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening." To the extent they are quantifiable, fugitive emissions are included in the potential to emit (and increases in same due to modification), if they occur at one of the following stationary sources:

- Any belonging to one of the 28 named PSD source categories listed in Table A-1, which were explicitly identified in Section 169 of the Act as being subject to a 100-tpy emissions threshold for classification of major sources;

- Any belonging to a stationary source category that as of August 7, 1980, is regulated (effective date of proposal) by New Source Performance Standards (NSPS) pursuant to Section 111 of the Act (listed in Table A-2); and

- Any belonging to a stationary source category that as of August 7, 1980, is regulated (effective date of promulgation) by National Emissions Standards for Hazardous Air Pollutants (NESHAP) pursuant to Section 112 of the Act (listed in Table A-2).

Note also that, if a source has been determined to be major, fugitive emissions, to the extent they are quantifiable, are considered in any subsequent analyses (e.g., air quality impact).

Fugitive emissions may vary widely from source to source. Examples of common sources of fugitive emission include:

- coal piles - particulate matter (PM);

- road dust - PM;

- quarries - PM; and

- leaking valves and flanges at refineries and organic chemical processing equipment - volatile organic compounds (VOC).

TABLE A-1. PSD SOURCE CATEGORIES WITH
100 tpy MAJOR SOURCE THRESHOLDS

1. Fossil fuel-fired steam electric plants of more than 250 million Btu/hr heat input
2. Coal cleaning plants (with thermal dryers)
3. Kraft pulp mills
4. Portland cement plants
5. Primary zinc smelters
6. Iron and steel mill plants
7. Primary aluminum ore reduction plants
8. Primary copper smelters
9. Municipal incinerators capable of charging more than 250 tons of refuse per day
10. Hydrofluoric acid plants
11. Sulfuric acid plants
12. Nitric acid plants
13. Petroleum refineries
14. Lime plants
15. Phosphate rock processing plants
16. Coke oven batteries
17. Sulfur recovery plants
18. Carbon black plants (furnace plants)
19. Primary lead smelters
20. Fuel conversion plants
21. Sintering plants
22. Secondary metal production plants
23. Chemical process plants
24. Fossil fuel boilers (or combinations thereof) totaling more than 250 million Btu/hr heat input
25. Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels
26. Taconite ore processing plants
27. Glass fiber processing plants
28. Charcoal production plants

TABLE A-2. NEW SOURCE PERFORMANCE STANDARDS PROPOSED AND NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS PROMULGATED PRIOR TO August 7, 1980

New Source Performance Standards 40 CFR 60

Source	Subpart	Affected Facility	Proposed Date
Phosphate rock plants	NN	Grinding, drying and calcining facilities	09/21/79
Ammonium sulfate manufacture	Pp	Ammonium sulfate dryer	02/04/80

National Emission Standards for Hazardous Air Pollutants 40 CFR 61

Pollutant	Subpart	Affected Facility	Promulgated Date
Beryllium	C	Extraction plants, ceramic plants, foundries, incinerators, propellant plants, machining operations	04/06/73
Beryllium, rocket motor firing	D	Rocket motor firing	04/06/73
Mercury	E	Ore processing, chloralkali manufacturing, sludge incinerators	04/06/73
Vinyl chloride	F	Ethylene dichloride manufacture via 02 HC1, vinyl chloride manufacture, polyvinyl chloride manufacture	10/21/76
Asbestos	M	Asbestos mills; roadway surfacing (asbestos tailings); demolition; spraying, fabri cation, waste disposal and insulting	04/06/73
		Manufacture of shotgun shells, renovation, fabrication, asphalt concrete, products containing asbestos	06/19/78

TABLE A-2. NEW SOURCE PERFORMANCE STANDARDS PROPOSED AND NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS PROMULGATED PRIOR TO August 7, 1980

New Source Performance Standards 40 CFR 60

Source	Subpart	Affected Facility	Proposed Date
Fossil-fuel fired steam generators for which construction is commenced after 08/17/71 and before 09/19/78	D	Utility and industrial (coal, oil, gas, wood, lignite)	08/17/71
Elect. utility steam generating units for which construction is commenced after 09/18/78	Da	Utility boilers (solid, liquid, and gaseous fuels)	09/19/78
Municipal incinerators (≥50 tons/day)	E	Incinerators	08/17/71
Portland cement plants	F	Kiln, clinker cooler	08/17/71
Nitric acid plants	G	Process equipment	08/17/71
Sulfuric acid plants	H	Process equipment	08/17/71
Asphalt concrete plants	I	Process equipment	06/11/73
Petroleum refineries	J	Fuel gas combustion devices Claus sulfur recovery	06/11/73
Storage vessels for petroleum liquids construction after 06/11/73 and prior to 05/19/78	K	Gasoline, crude oil, and distillate storage tanks ≥40,000 gallons capacity	06/11/73
Storage vessels for petroleum liquids construction after 05/18/78	Ka	Gasoline, crude oil, and distillate storage tanks ≥40,000 gallons capacity, vapor pressure ≥1.5	05/18/78
Secondary lead smelters and refineries	L	Blast and reverberatory furnaces, pot furnaces	06/11/73

TABLE A-2. NEW SOURCE PERFORMANCE STANDARDS PROPOSED AND NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS PROMULGATED PRIOR TO August 7, 1980

New Source Performance Standards 40 CFR 60

Source	Subpart	Affected Facility	Proposed Date
Secondary brass and bronze ingot production plants	M	Reverberatory and electric furnaces and blast furnaces	06/11/73
Iron and steel mills	N	Basic oxygen process furnaces (BOPF) Primary emission sources	06/11/73
Sewage treatment plants	O	Sludge incinerators	06/11/73
Primary copper smelters	P	Roaster, smelting furnace, converter dryers	10/16/74
Primary zinc smelters	Q	Roaster sintering machine	10/16/74
Primary lead smelters	R	Sintering machine, electric smelting furnace, converter Blast or reverberatory furnace, sintering machine discharge end	10/16/74
Primary aluminum reduction plants	S	Pot lines and anode bake plants	10/23/74
Primary aluminum reduction plants 111(d)		Pot lines and anode bake plants	04/11/79
Phosphate fertilizer industry	T	Wet process phosphoric	10/22/74
	U	Superphosphoric acid	
	V	Diammonium phosphate	
	W	Triple superphosphate products	
	X	Granular triple superphosphate products	
Coal preparation plants	Y	Air tables and thermal dryers	10/24/74
Ferroalloy production facilities	Z	Specific furnaces	10/21/74

TABLE A-2. NEW SOURCE PERFORMANCE STANDARDS PROPOSED AND NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS PROMULGATED PRIOR TO August 7, 1980

New Source Performance Standards 40 CFR 60

Source	Subpart	Affected Facility	Proposed Date
Steel plants: electric arc furnaces	AA	Electric arc furnaces	10/21/74
Kraft pulp mills	BB	Digesters, lime kiln recovery furnace, washer, evaporator, strippers, smelt and BLO tanks Recovery furnace, lime, kiln, smelt tank	09/24/76
Glass manufacturing plants	CC	Glass melting furnace	06/15/79
Grain elevators	DD	Truck loading and unloading stations, barge or ship loading and unloading stations railcar loading and unloading stations, and grain handling operations	01/13/77
Stationary gas turbines	GG	Each gas turbine	10/03/77
Lime manufacturing plants	HH	Rotary kiln, hydrator	05/03/77
Degreasers (organic solvent cleaners)	JJ	Cold cleaner, vapor degreaser, conveyorized degreaser	06/11/80
Lead acid battery manufacturing plants	KK	Lead oxide production grid casting, paste mixing, three-process operation and lead reclamation	01/14/80
Automobile and light-duty truck surface coating operations	MM	Prime, guide coat, and top coat operations at assembly plants	10/05/79

Due to the variability even among similar sources, fugitive emissions should be quantified through a source-specific engineering analysis. Suggested (but by no means all of the useful) references for fugitive emissions data and associated analytic techniques are listed in Table A-3.

Remember, if emissions can be "reasonably" captured and vented through a stack they are not considered "fugitive" under EPA regulations. In such cases, these emissions, to the extent they are quantifiable, would count toward the potential to emit regardless of source or facility type.

For example, the emissions from a rock crushing operation that could reasonably be equipped with a capture hood are not considered fugitive and would be included in the source's potential to emit.

As another example, VOC emissions, even if in relatively small quantities, coming from leaking valves inside a large furniture finishing plant, are typically captured and exhausted through the building ventilation system. They are, therefore, measurable and should be included in the potential to emit.

As a counter example, however, it may be unreasonable to expect that relatively small quantities of VOC emissions, caused by leaking valves at outside storage tanks of the large furniture finishing operation, could be captured and vented to a stack.

II.B.4. SECONDARY EMISSIONS

Secondary emissions are not considered in the potential emissions accounting procedure. Secondary emissions are those emissions which, although associated with a source, <u>are not emitted from the source itself</u>. Secondary emissions occur from any facility that is not a part of the source being reviewed, but which would not be constructed or increase its emissions except as a result of the construction or operation of the major stationary source or major modification. Secondary emissions do not include any emissions from any off-site facility which would be constructed or increase its emissions for some reason other than the construction or operation of the major stationary source or major modification.

TABLE A-3. SUGGESTED REFERENCES FOR ESTIMATING FUGITIVE EMISSIONS

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1. Emission Factors and Frequency of Leak Occurrence for Fittings in Refinery Process Units. Radian Corporation. EPA-600/2-79-044. February 1979.

2. Protocols for Generating Unit - Specific Emission Estimates for Equipment Leaks of VOC and VHAP. U.S. Environmental Protection Agency. EPA-450/3-88-0100.

3. Improving Air Quality: Guidance for Estimating Fugitive Emissions From Equipment. Chemical Manufacturers Association. January 1989.

4. Compilation of Air Pollutant Emission Factors, 3rd ed. U.S. Environmental Protection Agency. AP-42 (including Supplements 1-8). May 1978.

5. Technical Guidance for Control of Industrial Process Fugitive Particulate Emissions. Pedco Environmental, Inc. EPA-450/3-77-010. March 1977.

6. Fugitive Emissions From Integrated Iron and Steel Plants. Midwest Research Institute, Inc. EPA-600/2-78-050. March 1978.

7. Survey of Fugitive Dust from Coal Mines. Pedco Environmental, Inc. EPA-908/1-78-003. February 1978.

8. Workbook on Estimation of Emissions and Dispersion Modeling for Fugitive Particulate Sources. Utility Air Regulatory Group. September 1981.

9. Improved Emission factors for Fugitive Dust from Weston Surface Coal Mining Sources, Volumes I and II. U.S. Environmental Protection Agency. EPA-600/7-84-048.

10. Control of Open Fugitive Dust Sources. Midwest Research Institute. EPA-450/3-88-008. September 1988.

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> *An example is the emissions from an existing quarry owned by one company that doubles its production to supply aggregate to a cement plant proposed for construction as a major source on adjacent property by another company. The quarry's increase in emissions would be secondary emissions which the cement plant's ambient impacts analysis must consider.*

Secondary emissions do not include any emissions which come directly from a mobile source, such as emissions from the tailpipe of a motor vehicle or from the propulsion unit of a train or a vessel. This exclusion is limited, however, to only those mobile sources that are regulated under Title II of the Act (see 43 FR 26403 - note #9). Most off-road vehicles are not regulated under Title II and are usually treated as area sources. [As a result of a court decision in NRDC v. EPA, 725 F.2d 761 (D.C. Circuit 1984), emissions from vessels at berth ("dockside") not to be included in the determination of secondary emissions but are considered primary emissions for applicability purposes.]

Although secondary emissions are excluded from the potential emissions estimates used for applicability determinations, they must be considered in PSD analyses if PSD review is required. In order to be considered, however, secondary emissions must be specific, well-defined, quantifiable, and impact the same general area as the stationary source or modification undergoing review.

II.B.5. REGULATED POLLUTANTS

The potential to emit must be determined separately for each pollutant regulated by the Act and emitted by the new or modified source. Twenty-six compounds, 6 criteria and 20 noncriteria, are regulated as air pollutants by the Act as of December 31, 1989. They are listed in Table A-4. Note that EPA has designated PM-10 (particulate matter with an aerodynamic diameter less than 10 microns) as a criteria pollutant by promulgating NAAQS for this pollutant as a replacement for total PM. Thus, the determination of potential to emit for PM-10 emissions as well as total PM emissions (which are still regulated by many NSPS) is required in applicability determinations. Several halons and chlorofluorocarbon (CFC) compounds have been added to the list of regulated pollutants as a result of the ratification of the Montreal Protocol by the United States in January 1989.

II.B.6. METHODS FOR DETERMINING POTENTIAL TO EMIT

In determining a source's potential to emit, two parameters must be measured, calculated, or estimated in some way. They are:

- *the worst case uncontrolled emissions rate, which is based on the dirtiest fuels, and/or the highest emitting materials and operating conditions that the source is or will be permitted to use under federally-enforceable requirements, and*

- *the efficiency of the air pollution control system, if any, in use or contemplated for the worst case conditions, where the use of such equipment is federally-enforceable.*

TABLE A-4. SIGNIFICANT EMISSION RATES OF POLLUTANTS REGULATED UNDER THE CLEAN AIR ACT

	Pollutant	Emissions rate (tons/year)
	Pollutants listed at 40 CFR 52.21(b)(23)	
*	Carbon monoxide	100
*	Nitrogen oxides[a]	40
*	Sulfur dioxide[b]	40
*	Particulate matter (PM/PM-10)	25/15
*	Ozone (VOC)	40 (of VOC's)
*	Lead	0.6
	Asbestos	0.007
	Beryllium	0.0004
	Mercury	0.1
	Vinyl chloride	1
	Fluorides	3
	Sulfuric acid mist	7
	Hydrogen sulfide (H_2S)	10
	Total Reduced sulfur compounds (including H_2S)	10

* Criteria Pollutants

[a] Nitrogen dioxide is the compound regulated as a criteria pollutant; however, significant emissions are based on the sum of all oxides of nitrogen.

[b] Sulfur dioxide is the measured surrogate for the criteria pollutant sulfur oxides. Sulfur oxides have been made subject to regulation explicitly through the proposal of 40 CFR 60 Subpart J as of August 17, 1989.

TABLE A-4. (Concluded) SIGNIFICANT EMISSION RATES OF POLLUTANTS REGULATED UNDER THE CLEAN AIR ACT

Pollutant	Emissions rate (tons/year)
Other pollutants regulated by the Clean Air Act:[cd]	
Benzene	Any emission rate
Arsenic	Any emission rate
Radionuclides	Any emission rate
Radon-222	Any emission rate
Polonium-210	Any emission rate
CFC's 11,12, 112, 114, 115	Any emission rate
Halons 1211, 1301, 2402	Any emission rate

[c] Significant emission rates have not been promulgated for these pollutants, and until such time, any emissions by a new major sources or any increase in emissions at an existing major source due to modification, are "significant."

[d] Regulations covering several pollutants such as cadmium, coke oven emissions, and municipal waste incinerator emissions have recently been proposed. Applicants should, therefore, verify what pollutants have been regulated under the Act at the time of application.

Sources of the worst-case uncontrolled emissions and applicable control system efficiencies could be any of the following:

- *Emissions data from compliance tests or other source tests,*
- *Equipment vendor emissions data and guarantees;*
- *Emission limits and test data from EPA documents, including background information documents for new source performance standards, national emissions standards for hazardous air pollutants, and Section 111d standards for designated pollutants;*
- *AP-42 emission factors (see Table A-3, Reference 2);*
- *Emission factors from technical literature; and*
- *State emission inventory questionnaires for comparable sources.*

The effect of other restrictions (federally-enforceable and practically-enforceable) should also be factored into the results. The potential to emit of each pollutant, including fugitive emissions if applicable, is estimated for each individual emissions unit. The individual estimates are then summed by pollutant over all the emissions units at the stationary source.

II.C. EMISSIONS THRESHOLDS FOR PSD APPLICABILITY

II.C.1. MAJOR SOURCES

A source is a "major stationary source" or "major emitting facility" if:

(1) It can be classified in one of the 28 named source categories listed in Section 169 of the CAA (see Table A-1) and it emits or has the potential to emit 100 tpy or more of any pollutant regulated by the Act, or

(2) it is any other stationary source that emits or has the potential to emit 250 tons per year or more of any pollutant regulated by the CAA.

For example, one of the 28 PSD source categories subject to the 100-tpy threshold is fossil fuel-fired steam generators with a heat input greater than 250 million Btu/hr. Consequently, a 300 million Btu/hr boiler that is designed and *permitted to burn any fossil fuel, i.e., coal, oil, natural gas or lignite, that emits 100 tpy or more of any regulated pollutant, e.g., SO_2, is a major stationary source. If, however, the boiler were designed and permitted to burn wood only, it would not be classified as one of the 28 PSD sources and would instead be subject to the 250 tpy threshold.*

A single, fossil fuel-fired boiler with a maximum heat input capacity of 300 million Btu/hr takes a federally-enforceable design limitation that restricts heat input to 240 million Btu/hr. Consequently, this source would not be classified within one of the 28 categories and would therefore be subject to the 250-tpy, rather than the 100-tpy, emissions threshold.

A situation frequently occurs in which an emissions unit that is included in the 28 listed source categories (and so is subject to a 100 tpy threshold), is located within a parent source whose primary activity is not on the list (and is therefore subject to a 250 tpy threshold). A source which, when considered alone, would be major (and hence subject to PSD) cannot "hide" within a different and less restrictive source category in order to escape applicability.

As an example, a proposed coal mining operation will use an on-site coal cleaning plant with a thermal dryer. The source will be defined as a coal mine because the cleaning plant will only treat coal from the mine. The mine's potential to emit (including emissions from the thermal dryer) is less than 250 tpy for every regulated pollutant; therefore, it is a "minor" source. The estimated emissions from the thermal dryer, however, will be 150 tpy particulate matter. Thermal dryers are included in the list of 28 source categories that are subject to the 100 tpy major source threshold. Consequently, the thermal dryer would be considered an emissions unit that by itself is a major source and therefore is subject to PSD review, even though the primary activity is not.

Furthermore, when a "minor" source, i.e., one that does not meet the definition of "major," makes a physical change or change in the method of operation that is by itself a major source, that physical or operational change constitutes a major stationary source that is subject to PSD review.

To illustrate, consider the following scenarios at an existing glass fiber processing plant, which proposes to add new equipment to increase production. Glass fiber processing plants are included in the list of 28 source categories that are subject to the 100-tpy major source threshold. The existing plant emits 40 tpy particulate, which is both its potential to emit and permitted allowable rate. It also has a potential to emit all other pollutants in less than major quantities; therefore it is a minor source.

> *Scenario 1 - The physical change will increase the source's potential to emit particulate matter by 50 tpy. Since the plant is a minor source and the increase is not major by itself, the change is not subject to PSD review.*
>
> *Scenario 2 - The physical change will increase the source's potential to emit particulate matter by 65 tpy. Since the plant is a minor source and the increase is not major by itself, neither is subject to PSD review. However, the source's potential to emit after the change will exceed the 100-tpy major source threshold, so future modifications will be scrutinized under the netting provisions (see section A.3.2).*
>
> *Scenario 3 - The physical change will increase the source's potential to emit particulate matter by 110 tpy. Since the existing plant is a minor source and the change by itself results in an emissions increase greater than the major source threshold, that change is subject to PSD review. Furthermore, the physical change makes the entire plant a major source, so future physical changes or changes in the method of operation will be scrutinized against the criteria for major modifications (see section II.A.3.2).*

II.C.2. SIGNIFICANT EMISSIONS

A PSD review is triggered in certain instances when emissions associated with a new major source or emissions increases resulting from a major modification are "significant." "Significant" emissions thresholds are defined two ways. The first is in terms of emission rates (tons/year). Table A-4 listed the pollutants for which significant emissions rates have been established.

Significant increases in emission rates are subject to PSD review in two circumstances:

(1) For a new source which is major for at least one regulated attainment or noncriteria pollutant, i.e., is subject to PSD review, all pollutants for which the area is not classified as nonattainment and which are emitted in amounts equal to or greater than those specified in Table A-4 are also subject to PSD review for its VOC emissions.

For example, an automotive assembly plant is planned for an attainment area for all criteria pollutants. The plant has a potential to emit 350 tpy VOC, 50 tpy NO_x, 60 tpy SO_2, and 10 tpy PM including 5 tpy PM-10. The 350 tpy VOC exceeds the major source threshold, and therefore subjects the plant to PSD review. The "significant" emissions thresholds for NO_x and SO_2 are 40 tpy; therefore, the NO_x and SO_2 emissions, also, will be subject to PSD review. The PM and PM-10 emissions will not exceed their significant emissions thresholds; therefore they are not subject to review.

(2) For a modification to an existing major stationary source, if both the potential increase in emissions due to the modification itself, and the resulting net emissions increase of any regulated, attainment or noncriteria pollutants are equal to or greater than the respective pollutants' significant emissions rates listed in Table A-4, the modification is "major," and subject to PSD review. Modifications are discussed in detail in Section II.D.

The second type of "significant" emissions threshold is defined as any emissions rate at a new major stationary source (or any net emissions increase associated with a modification to an existing major stationary source) that is constructed within 10 kilometers of a Class I area, and which would increase the 24-hour average concentration of any regulated pollutant in that area by 1 $\mu g/m^3$ or greater. Exceedence of this threshold triggers PSD review.

II.D. LOCAL AIR QUALITY CONSIDERATIONS FOR CRITERIA POLLUTANTS

The air quality, i.e., attainment status, of the area of a proposed new source or modified existing source will impact the applicability determination in regard to the pollutants that are subject to PSD review. As previously stated, if a new source locates in an area designated attainment or unclassifiable for any criteria pollutant, PSD review will apply to any pollutant for which the potential to emit is major (or significant, if the source is major) so long as the area is not nonattainment for that pollutant.

> *For example, a kraft pulp mill is proposed for an attainment area for SO_2, and its potential to emit SO_2 equals 55 tpy. Its potential to emit total reduced sulfur (TRS) a noncriteria pollutant, equals 295 tpy. Its potential to emit VOC will be 45 tpy and PM/PM-10, 30/5 tpy; however, the area is designated nonattainment for ozone and PM. Applicability would be assessed as follows:*
>
> > *The source would be major and subject to PSD review due to the noncriteria TRS emissions.*
> >
> > *The SO_2 emissions would therefore be subject to PSD because they are significant and the area is attainment for SO_2.*
> >
> > *The VOC emission and PM emissions would not be subject to PSD, even though their emissions are significant, because the area is designated nonattainment for those pollutants.*
> >
> > *The PM-10 emissions are neither major nor significant and would therefore not be subject to review.*

Similarly, if the modification of an existing major source, which is located in an attainment area for any criteria pollutant, results in a significant increase in potential to emit and a significant net emissions increase, the modification is subject to PSD, unless the location is designated as nonattainment for that pollutant.

Note that if the source is major for a pollutant for which an area is designated nonattainment, all significant emissions or significant emissions increases of pollutants for which the area is attainment or unclassifiable are still subject to PSD review.

II.E. SUMMARY OF MAJOR NEW SOURCE APPLICABILITY

The elements and associated information necessary for determining PSD applicability to **new** sources are outlined as follows:

Element 1 - Define the source

! includes all related activities classified under the same 2-digit SIC Code number

! must have the same owner or operator

! must be located on contiguous or adjacent properties

! includes all support facilities

Element 2 - Define applicability thresholds for major source as a whole (primary activity)

! 100 tpy for individual emissions units or groups of units that are included in the list of 28 source categories identified in Section 169 of the CAA

! 250 tpy for all other sources

Element 3 - Define project emissions (potential to emit)

! Reflects federally-enforceable air pollution control efficiency, operating conditions, and permit limitations

! Determined for each pollutant by each emissions unit

! Summed by pollutant over all emissions units

! Includes fugitive emissions for 28 listed source categories and sources subject to NSPS or NESHAPS as of August 7, 1980

Element 4 - Assess local area attainment status

! Area must be attainment or unclassifiable for at least one criteria pollutant for PSD to apply

Element 5 - Determine if source is major by comparing its potential emissions to appropriate major source threshold

- Major if <u>any</u> pollutant emitted by defined source exceeds thresholds, regardless of area designation, i.e., attainment, nonattainment, or noncriteria pollutants

- Individual unit is major if classified as a source in one of the 28 regulated source categories and emissions exceed an applicable 100-tpy threshold

Element 6 - Determine pollutants subject to PSD review

- Each attainment area and noncriteria pollutant emitted in "significant" quantities

- Any emissions or emissions increase from a major source that results in an increase of 1 $\mu g/m^3$ (24 hour average) or more in a Class I area if the major source is located or constructed within 10 kilometers of that Class I area.

II.F. NEW SOURCE APPLICABILITY EXAMPLE

The following example provided is for illustration only. The example source is fictitious and has been created to highlight many of the aspects of the PSD applicability process for a new source.

In this example the proposed project is a new coal-fired electric plant. The plant will have two 600-MW lignite-fired boilers. The proposed location is near a separately-owned surface lignite mine, which will supply the fuel requirements of the power plant, and will therefore, have to increase its mining capacity with new equipment. The lignite coal will be mined and then transported to the power plant to be crushed, screened, stored, pulverized and fed to the boilers. The power plant has informed the lignite coal mine that the coal will not have to be cleaned, so the mine will not expand its coal cleaning capacity. The power plant will have on-site coal and limestone storage and handling facilities. In addition, a comparatively small auxiliary boiler will be installed to provide steam for the facility when the main boilers are inoperable. The area is designated attainment for all criteria pollutants.

The applicant proposes pollution control devices for the two 600-MW boilers which include:

- an electrostatic precipitator (ESP) for PM/PM-10 emissions control,
- a limestone scrubber flue gas desulfurization (FGD) system for SO_2 emissions control;
- low-nitrogen oxide (NO_x) burners and low-excess-air firing for NO_x emissions control; and
- controlled combustion for CO emissions control.

The first step is to determine what constitutes the source (or sources). A source is defined as all pollutant-emitting activities associated with the same industrial grouping, located on contiguous or adjacent sites, and under common control or ownership. Industrial groupings are generally defined by two-digit SIC codes. The power plant is classified as SIC major group 49; the nearby mine is SIC major group 12. They are neither under the same SIC major group number nor have the same owners, so they constitute separate sources.

The second step is to establish which major source thresholds are applicable in this case. The proposed power plant is a fossil fuel-fired steam electric plant with more than 250 million Btu/hr of heat input, making it a source included in one of the 28 PSD-listed categories. It is therefore subject to both the 100 ton per year criterion for any regulated pollutant used to determine whether a source is major and to the requirement that quantifiable fugitive emissions be included in determining potential to emit.

The emissions units at the mine are neither classified within one of the 28 PSD source categories nor regulated under Sections 111 or 112 of the Act. Therefore, the mine is compared against the 250 tpy major source threshold and fugitive emissions from the mining operations are exempt from consideration in determining whether the mine is a major stationary source.

The third step is to define the project emissions. To arrive at the potential to emit of the proposed power plant, the applicant must consider all quantifiable stack and fugitive emissions of each regulated pollutant (i.e., SO_2, NO_x, PM, PM-10, CO, VOC, lead, and the noncriteria pollutants). Therefore, fugitive PM/PM-10 emissions from haul roads, disturbed areas, coal piles, and other sources must be included in calculating the power plant's potential to emit.

All stack and fugitive emissions estimates have been obtained through detailed engineering analysis of each emissions unit using the best available data or estimating technique. Fugitive emissions are added to the emissions from the two main boilers and the auxiliary boiler in order to arrive at the total potential to emit of each regulated pollutant. The auxiliary boiler in this case is restricted by enforceable limits on operating hours proposed to be included in the source's PSD permit. If the auxiliary boiler were not limited in hours of operation, its contribution would be based on full, continuous operation, and the resulting potential emissions estimates would be higher.

The potential to emit SO_2, NO_x, PM, CO, and sulfuric acid mist each exceeds 100 tons per year. From data collected at other lignite fired power plants it is known that emissions of lead, beryllium, mercury, fluorides, sulfuric acid mist and arsenic should also be quantified. It is known that fluoride compounds are contained in the coal in significant quantities; however, engineering analyses show fluoride removal in the proposed limestone scrubber will result in insignificant stack emissions. Similarly, liquid absorption, absorption of fly ash removed in the ESP, and removal of bottom ash have been shown to maintain emissions of lead and the other regulated noncriteria pollutants below significance levels.

The only emissions at the existing mine, and consequently the only emissions increase that will occur from the expansion to serve the power plant, are fugitive PM/PM-10 emissions from mining operations. The mine's potential to emit, for PSD applicability purposes, is zero and the mine is not subject to a PSD review. The increase in fugitive emissions from the mine, however, will be classified as secondary emissions with respect to the power plant and, therefore, must be considered in the air quality analysis and additional impacts analysis for the proposed power plant if the power plant is subject to PSD review.

The next step is to compare the potential emissions of the power plant to the 100 ton per year major source threshold. If the potential to emit of any regulated pollutant is 100 tons per year or more, the power plant is classified as a major stationary source for PSD purposes. In this case, the plant is classified as a major source because SO_2, NO_x, PM, CO, and sulfuric acid mist emissions each exceed 100 tons per year. (Note that emissions of any one of these pollutants classifies the source as major.)

Once it has been determined that the proposed source is major, any regulated pollutant (for which the location of the source is not classified as nonattainment) with significant emissions is subject to a PSD review. The applicant quantified, through coal and captured fly ash analyses and through performance test results from existing sources burning equivalent coals, emissions of fluorides, beryllium, lead, mercury, and the other regulated noncriteria pollutants to determine if their emissions exceed the significance levels (see Table A-4.). Pollutants with less than significant emissions are not subject to PSD review requirements (assuming the proposed controls are accepted as BACT for SO_2, or the application of BACT for SO_2 results in equivalent or lower noncriteria pollutant emissions).

Note that, because the proposed construction site is not within 10 kilometers of a Class I area, the source's emissions are not subject to the Class I area significance criteria.

III. MAJOR MODIFICATION APPLICABILITY

A modification is subject to PSD review only if (1) the existing source that is modified is "major," and (2) the net emissions increase of any pollutant emitted by the source, as a result of the modification, is "significant," i.e., equal to or greater than the emissions rates given on Table A-4 (unless the source is located in a nonattainment area for that pollutant). Note also that any net emissions increase in a regulated pollutant at a major stationary source that is located within 10 kilometers of a Class I area, and which will cause an increase of 1 $\mu g/m^3$ (24 hour average) or more in the ambient concentration of that pollutant within that Class I area, is "significant".

Typical examples of modifications include (but are not limited to) replacing a boiler at a chemical plant, construction of a new surface coating line at an assembly plant, and a switch from coal to gas requiring a physical change to the plant, e.g., new piping, etc.

As discussed earlier, when a "minor" source, i.e., one that does not meet the definition of "major," makes a physical change or change in the method of operation that is by itself a major source, that physical or operational change constitutes a major stationary source that is subject to PSD review. Also, if an existing minor source becomes a major source as a result of a SIP relaxation, then it becomes subject to PSD requirements just as if construction had not yet commenced on the source or the modification.

III.A. ACTIVITIES THAT ARE NOT MODIFICATIONS

The regulations do not define "physical change" or "change in the method of operation" precisely; however, they exclude from those activities certain specific types of events described below.

(1) Routine maintenance, repair and replacement.

[Sources should discuss any project that will significantly increase actual emissions to the atmosphere with their respective permitting authority, as to whether that project is considered routine maintenance, repair or replacement.]

(2) A fuel switch due to an order under the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or due to a natural gas curtailment plan under the Federal Power Act.

(3) A fuel switch due to an order or rule under section 125 of the CAA.

(4) A switch at a steam generating unit to a fuel derived in whole or in part from municipal solid waste.

(5) A switch to a fuel or raw material which (a) the source was capable of accommodating before January 6, 1975, so long as the switch would not be prohibited by any federally-enforceable permit condition established after that date under a federally approved SIP (including any PSD permit condition) or a federal PSD permit, or (b) the source is approved to make under a PSD permit.

(6) Any increase in the hours or rate of operation of a source, so long as the increase would not be prohibited by any federally-enforceable permit condition established after January 6, 1975 under a federally approved SIP (including any PSD permit condition) or a federal PSD permit.

(7) A change in the ownership of a stationary source.

For more details see 40 CFR 52.21(b)(2)(iii).

Notwithstanding the above, if a significant increase in actual emissions of a regulated pollutant occurs at an existing major source as a result of a physical change or change in the method of operation of that source, the "<u>net</u> emissions increase" of that pollutant must be determined.

III.B. EMISSIONS NETTING

Emissions netting is a term that refers to the process of considering certain previous and prospective emissions changes at an existing major source to determine if a "net emissions increase" of a pollutant will result from a proposed physical change or change in method of operation. If a net emissions increase is shown to result, PSD applies to each pollutant's emissions for which the net increase is "significant", as shown in Table A-4.

The process used to determine whether there will be a net emissions increase will result uses the following equation:

Net Emissions Change

EQUALS

Emissions <u>increases</u> associated with the proposed modification

MINUS

Source-wide creditable contemporaneous emissions <u>decreases</u>

PLUS

Source-wide creditable contemporaneous emissions <u>increases</u>

Consideration of contemporaneous emissions changes is allowed <u>only</u> in cases involving <u>existing</u> <u>major</u> <u>sources</u>. In other words, minor sources are not eligible to net emissions changes. As discussed earlier, existing minor sources are subject to PSD review only when proposing to increase emissions by "major" (e.g., 100 or 250 tpy, as applicable) amounts, which, for PSD purposes, are considered and reviewed as a major new source.

For example, an existing minor source (subject to the 100 tpy major source cutoff) is proposing a modification which involves the shutdown and removal of an old emissions unit (providing an actual contemporaneous reduction in NOx emissions of 75 tpy) and the construction of two new units with total potential NOx emissions of 110 tpy. Since the existing source is minor, the 75 tpy reduction is not considered for PSD applicability purposes. Consequently, PSD applies to the new units because the emissions increase of 110 tpy is itself "major". The new units are then subject to a PSD review for NOx and for any other regulated pollutant with a "significant" potential to emit.

The consideration of contemporaneous emissions changes is also source specific. Netting must take place at the same stationary source; emissions reductions cannot be traded between stationary sources.

III.B.1. ACCUMULATION OF EMISSIONS

If the proposed emissions increase at a major source is by itself (without considering any decreases) less than "significant", EPA policy does not require consideration of previous contemporaneous small (i.e., less than significant) emissions increases at the source. In other words, the netting equation (the summation of contemporaneous emissions increases and decreases) is not triggered unless there will be a significant emissions increase from the proposed modification.

For example, a major source experienced less than significant increases of NO_x (30 tpy) and SO_2 (15 tpy) 2 years ago, and a decrease of SO_2 (50 tpy) 3 years ago. The source now proposes to add a new process unit with an associated emissions increase of 35 tpy NO_x and 80 tpy SO_2. For SO_2, the proposed 80 tpy increase from the modification by itself (before netting) is significant. The contemporaneous net emissions change is determined, by taking the algebraic sum of (-50) and (+15) and (+80), which equals +45 tpy. Therefore, the proposed modification is a major modification and a PSD review for SO_2 is required. However, the NO_x increase from the proposed modification is by itself less than significant. Consequently, netting for PSD applicability purposes is not performed for NO_x (even though the modification is major for SO_2) and a PSD review is not needed for NO_x.

It is important to note that when <u>any</u> emissions decrease is claimed (including those associated with the proposed modification), <u>all</u> source-wide creditable and contemporaneous emissions increases and decreases of the pollutant subject to netting must be included in the PSD applicability determination.

A deliberate decision to split an otherwise "significant" project into two or more smaller projects to avoid PSD review would be viewed as circumvention and would subject the entire project to enforcement action if construction on any of the small projects commences without a valid PSD permit.

For example, an automobile and truck tire manufacturing plant, an existing major source, plans to increase its production of both types of tires by *"debottlenecking" its production processes. For its passenger tire line, the source applies for and is granted a "minor" modification permit for a new extruder that will increase VOC emissions by 39 tons/yr. A few months later, the source applies for a "minor" modification permit to construct a new tread-end cementer on the same line which will increase VOC emissions by 12 tons/yr. The EPA would likely consider these proposals as an attempt to circumvent the regulations because the two proposals are related in terms of an overall project to increase source-wide production capacity. The important point in this example is that the two proposals are sufficiently related that the PSD regulations would consider them a single project.*

Usually, at least two basic questions should be asked when evaluating the construction of multiple minor projects to determine if they should have been considered a single project. First, were the projects proposed over a relatively short period of time? Second, could the changes be considered as part of a single project?

III.B.2. CONTEMPORANEOUS EMISSIONS CHANGES

The PSD definition of a net emissions increase [40 CFR 52.21(b)(3)(i)] consists of two <u>additive</u> components as follows:

(a) Any <u>increases</u> in actual emissions <u>from</u> a particular physical change or change in method of operation at a stationary source; and

(b) Any other <u>increase</u> <u>and</u> <u>decreases</u> <u>in</u> <u>actual</u> <u>emissions</u> at the source that are contemporaneous with the particular change and are otherwise creditable.

The first component narrowly includes only the emissions increases associated with a particular change at the source. The second component more broadly includes all contemporaneous, source-wide (occurring anywhere at the entire source), creditable emission increases and decreases.

To be <u>contemporaneous</u>, changes in <u>actual</u> emissions must have occurred after January 6, 1975. The changes must also occur within a period beginning 5 years before the date construction is expected to commence on the proposed modification (reviewing agencies may use the date construction is <u>scheduled</u> to commence provided that it is reasonable considering the time needed to issue a final permit) and ending when the emissions increase from the modification occurs. An increase resulting from a physical change at a source occurs when the new emissions unit becomes operational and begins to emit a pollutant. A replacement that requires a shakedown period becomes operational only after a reasonable shakedown period, not to exceed 180 days. Since the date construction actually will commence is unknown at the time the applicability determination takes place and is simply a scheduled date projected by the source, the contemporaneous period may shift if construction does not commence as scheduled. Many States have developed PSD regulations that allow different time frames for definitions of contemporaneous. Where approved by EPA, the time periods specified in these regulations govern the contemporaneous timeframe.

III.B.3. CREDITABLE CONTEMPORANEOUS EMISSIONS CHANGES

There are further restrictions on the contemporaneous emissions changes that can be credited in determining net increases. To be creditable, <u>a contemporaneous reduction must be federally-enforceable</u> on and after the date construction on the proposed modification begins. The actual reduction must take place before the date that the emissions increase from any of the new or modified emissions units occurs. In addition, the reviewing agency must ensure that the source has maintained any contemporaneous decrease which the source claims has occurred in the past. The source must either demonstrate that the decrease was federally-enforceable at the time the source claims it occurred, or it must otherwise demonstrate that the decrease was maintained until the present time and will continue until it becomes federally-enforceable. <u>An emissions decrease cannot occur at, and therefore, cannot be credited from an emissions unit which was never constructed or operated, including units that received a PSD permit.</u>

Reductions must be of the same pollutant as the emissions increase from the proposed modification and must be qualitatively equivalent in their effects on public health and welfare to the effects attributable to the proposed increase. Current EPA policy is to assume that an emissions decrease will have approximately the same qualitative significance for public health and welfare as that attributed to an increase, unless the reviewing agency has reason to believe that the reduction in ambient concentrations from the emissions decrease will not be sufficient to prevent the proposed emissions increase from causing or contributing to a violation of any NAAQS or PSD increment. In such cases, the applicant must demonstrate that the proposed netting transaction will not cause or contribute to an air quality violation before the emissions reduction may be credited. Also, in situations where a State is implementing an air toxics program, proposed netting transactions may be subject to additional tests regarding the health and welfare equivalency demonstration. For example, a State may prohibit netting between certain groups of toxic subspecies or apply netting ratios greater than the normally required 1:1 between certain groups of toxic pollutants.

A contemporaneous emissions increase occurs as the result of a physical change or change in the method of operation at the source and is creditable to the extent that the new emissions level exceeds the old emissions level. The "old" emissions level for an emissions unit equals the average rate (in tons per year) at which the unit actually emitted the pollutant during the 2-year period just prior to the physical or operational change which resulted in the emissions increase. In certain limited situations where the applicant adequately demonstrates that the prior 2 years is not representative of normal source operation, a different (2 year) time period may be used upon a determination by the reviewing agency that it is more representative of normal source operation. Normal source operations may be affected by strikes, retooling, major industrial accidents and other catastrophic occurrences. The "new" emissions levels for a new or modified emissions unit which has not begun normal operation is its potential to emit.

An emissions increase or decrease is creditable only if the relevant reviewing authority has <u>not</u> relied on it in issuing a PSD permit for the source, and the permit is still in effect when the increase in actual emissions from the proposed modification occurs. A reviewing authority relies on an increase or decrease when, after taking the increase or decrease into account, it concludes that a proposed project would not cause or contribute to a violation of an increment or ambient standard. In other words, an emissions change at an emissions point which was considered in the issuance of a previous PSD permit for the source is not included in the source's "net emissions increase" calculation. This is done to avoid "double counting" of emissions changes.

> *For example, an emissions increase or decrease already considered in a source's PSD permit (state or federal) can not be considered a contemporaneous increase or decrease since the increases or decrease was obviously relied upon for the purpose of issuing the permit. Otherwise the increase or decrease would not have been specified in the permit. In another example, a decrease in emissions from having previously switched to a less polluting fuel (e.g., oil to gas) at an existing emissions unit would not be creditable if the source had, in obtaining a PSD permit (which is still in effect) for a new emissions unit, modeled the source's ambient impact using the less polluting fuel.*

Changes in PM (PM/PM-10), SO_2 and NO_x emissions are a subset of creditable contemporaneous changes that also affect the available increment. For these pollutants, emissions changes which do not affect allowable PSD increment consumption are not creditable.

III.B.4. CREDITABLE AMOUNT

As mentioned above, only contemporaneous and creditable emissions changes are considered in determining the source-wide net emissions change. All contemporaneous and creditable emissions increases and decreases at the source must, however, be considered. The amount of each contemporaneous and creditable emissions increase or decrease involves determining old and new actual annual emissions levels for each affected emission unit.

The following basic criteria should be used when quantifying the increase or decrease:

- For proposed new or modified units which have not begun normal operations, the potential to emit must be used to determine the <u>increase</u> from the units.

- For an existing unit, actual emissions just prior to either a physical or operational change are based on the lower of the actual or allowable emissions levels. This "old" emissions level equals the average rate (in tons per year) at which the unit actually emitted the pollutant during the 2-year period just prior to the change which resulted in the emissions increase. These emissions are calculated using the <u>actual</u> hours of operation, capacity, fuel combusted and other parameters which affected the unit's emissions over the 2-year averaging period. In certain limited circumstances, where sufficient representative operating data do not exist to determine historic actual emissions and the reviewing agency has reason to believe that the source is operating at or near its allowable emissions level, the reviewing agency may presume that source-specific allowable emissions [or a fraction thereof] are equivalent to (and therefore are used in place of) actual emissions at the unit. For determining the difference in emissions from the change at the unit, emissions after the change are the potential to emit from the units.

- A source cannot receive emission reduction credit for reducing any portion of actual emissions which resulted because the source was operating out of compliance.

- An emissions decrease cannot be credited from a unit that has not been constructed or operated.

Examples of how to apply these creditability criteria for prospective emissions reductions is shown in Figure A-1. As shown in Case I of Figure A-1, the potential to emit for an existing emissions unit (which is based on the existing allowable emission rate) is greater than the actual emissions, which are based on actual operating data (e.g., type and amount of fuel combusted at the unit) for the past 2 years. The source proposes to switch to a lower sulfur fuel. The amount of the reduction in this case is the difference between the actual emissions and the revised allowable emissions. (Recall that *for reductions to be creditable, the revised allowable emission rate must be ensured with federally-enforceable limits.)*

Figure A-1 also illustrates in Case II that the previous allowable emissions were much higher than the potential to emit. Common examples are PM sources permitted according to process weight tables contained in most SIPs. Since process weight tables apply to a range of source types, they often overpredict actual emission rates for individual sources. In such cases, as in the previous case, the <u>*only*</u> *creditable contemporaneous reduction is the difference between the actual emissions and the revised allowable emission rate for the existing emissions unit.*

Case III in Figure A-1 illustrates a potential violation situation where the actual emissions level exceeds allowable limit. The creditable reduction in this case is the difference between what the emissions would have been from the unit had the source been in compliance with its old allowable limits (considering its actual operations) and its revised allowable emissions level.

Consider a more specific example, where a source has an emissions unit with an annual allowable emissions rate of 200 tpy based on full capacity year-round operation and an <u>*hourly*</u> *unit-specific allowable emission rate. The source is, however, out of compliance with the allowable hourly emission rate by a factor of two. Consequently, if the unit were to be operated year-round at full capacity it would emit 400 tpy. However, in this case, although the unit operated at full capacity, it was operated on the average 75 percent of the time for the past 2 years. Consequently, for the past 2 years average actual emissions were 300 tpy. The unit is now to be shutdown. Assuming the reduction is otherwise creditable, the reduction from the shutdown is its allowable emissions prorated by its operating factor (200 tpy x .75 = 150 tpy).*

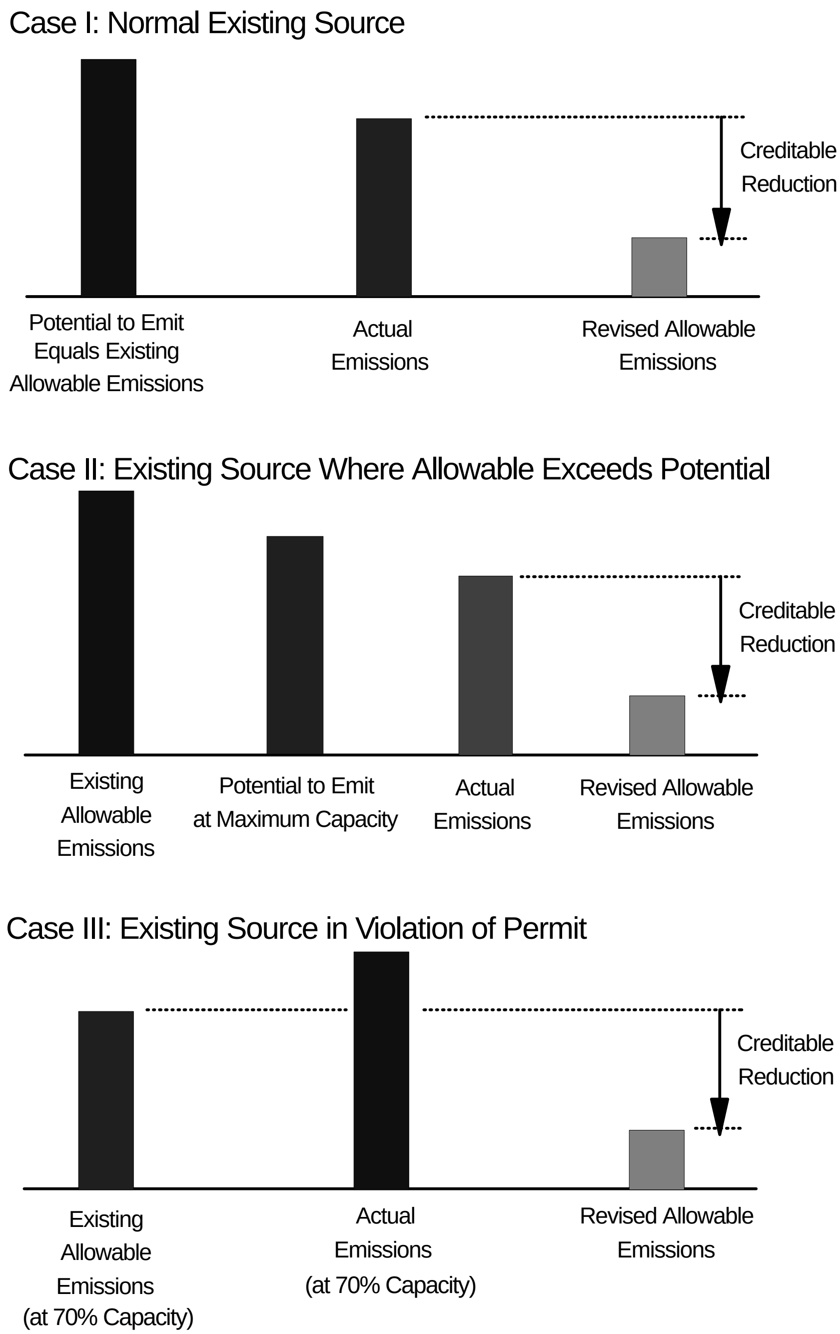

Figure A-1. Creditable Reductions in Actual Emissions

III.B.5. SUGGESTED EMISSIONS NETTING PROCEDURE

Through its review of many emissions netting transactions, EPA has found that, either because of confusion or misunderstanding, sources have used various netting procedures, some of which result in cases where projects should have been subjected to PSD but were not. Some of the most common errors include:

- Not including contemporaneous emissions increases when considering decreases;
- Improperly using <u>allowable</u> emissions instead of <u>actual</u> emissions level for the "old" emissions level for existing units;
- Using prospective (proposed) unrelated emissions decreases to counterbalance proposed emission increases without also examining all previous contemporaneous emissions changes;
- Not considering a contemporaneous increase creditable because the increase previously netted out of review by relying on a past decrease which was, <u>but is no longer</u>, contemporaneous. If contemporaneous and otherwise creditable, the increase must be considered in the netting calculus.
- Not properly documenting all contemporaneous emissions changes; and
- Not ensuring that emissions decreases are covered by federally-enforceable restrictions, which is a requirement for creditability.

For the purpose of minimizing confusion and improper applicability determinations, the six-step procedure shown in Table A-5 and described below is recommended in applying the emissions netting equation. Already assumed in this procedure is that the existing source has been defined, its major source status has been confirmed and the air quality status in the area is attainment for at least one criteria pollutant.

TABLE A-5. Procedures for Determining the Net Emissions Change at a Source

Determine the emissions increases (but not any decreases) from the proposed project. If increases are significant, proceed; if not, the sources is not subject to review.

Determine the beginning and ending dates of the contemporaneous period as it relates to the proposed modification.

Determine which emissions units at the source experienced (or will experience, including any proposed decreases resulting from the proposed project) a creditable increase or decrease in emissions during the contemporaneous period.

Determine which emissions changes are creditable.

Determine, on a pollutant-by-pollutant basis, the amount of each contemporaneous and creditable emissions increase and decrease.

Sum all contemporaneous and creditable increases and decreases with the increase from the proposed modification to determine if a significant net emissions increase will occur.

Step 1. Determine the emissions increases from the proposed project.

First, only the emissions increases expected to result from the proposed project are examined. This includes emissions increases from the new and modified emissions units and any other plant-wide emissions increases (e.g., debottlenecking increases) that will occur as a result of the proposed modification. [Proposed emissions decreases occurring elsewhere at the source are not considered at this point. Emission decreases associated with a proposed project (such as a boiler replacement) are contemporaneous and may be considered along with other contemporaneous emissions changes at the source. However, they are <u>not</u> considered at this point in the analysis.]

A PSD review applies only to those regulated pollutants with a significant emissions increase from the proposed modification. If the proposed project will not result in a significant emissions increase of any regulated pollutant, the project is exempt from PSD review and the PSD applicability process is completed. However, if this is not the case, each regulated pollutant to be emitted in a significant amount is subject to a PSD review unless the source can demonstrate (using steps 2-6) that the sum of all other source-wide contemporaneous and creditable emissions increases and decreases would be less than significant.

Step 2 Determine the beginning and ending dates of the contemporaneous period as it relates to the proposed modification.

The period begins on the date 5 years (some States may have a different time period) before construction commences on the proposed modification. It ends on the date the emissions increase from the proposed modification occurs.

Step 3 Determine which emissions units at the source have experienced an increase or decrease in emissions during the contemporaneous period.

Usually, creditable emissions increases are associated with a physical change or change in the method of operation at a source which did not require a PSD permit. For example, creditable emissions increases may come from the construction of a new unit, a fuel switch or an increase in operation that (a) would have otherwise been subject to PSD but instead netted out of review (per steps 1-6) or (b) resulted in a less than significant emissions increase (per step 1).

Decreases are creditable reductions in actual emissions from an emissions unit that are, or can be made, federally-enforceable. A physical change or change in the method of operation is also associated with the types of decreases that are creditable. Specifically, in the case of an emissions decrease, once the decrease has been made federally-enforceable, any proposed increase above the federally-enforceable level must constitute a physical change or change in the method of operation at the source or the reduction is not considered creditable. For example, a source could only receive an emissions decrease for netting purposes from a unit that has been taken out of operation if, due to the imposition of federally-enforceable restrictions preventing the use of the unit, a proposal to reactivate the unit would constitute a physical change or change in the method of operation at the source. If operating the unit was not considered a physical or operational change, the unit could go back to its prior level of operation at any time, thereby producing only a "paper" reduction, which is not creditable.

Step 4 Determine which emissions changes are creditable.

The following basic rules apply:

1) A increase or decrease is creditable only if the relevant reviewing authority has not relied upon it in previously issuing a PSD permit and the permit is in effect when the increase from the proposed modification occurs. As stated earlier, a reviewing authority "relies" on an increase or decrease when, after taking the increase or decrease into account, it concludes in issuing a PSD permit that a project would not cause or contribute to a violation of a PSD increment or ambient standard.

2) For pollutants with PSD increments (i.e., SO2, particulate matter and NOx), an increase or decrease in actual emissions which occurs before the baseline date in an area is creditable only if it would be considered in calculating how much of an increment remains available for the pollutant in question. An example of this situation is a 39 tpy NO_x emissions increase resulting from a new heater at a major source in 1987, prior to the NO_x increment baseline date. Because these emissions do not affect the allowable PSD increment, they need not be considered in 1990 when the source proposes another unrelated project. The new emissions level for the heater (up to 39 tpy) would be adjusted downward to the old level (zero) in the accounting exercise. Likewise, decreases which occurred before the baseline date was triggered cannot be credited after the baseline date. Such reductions are included in the baseline concentration and are not considered in calculating PSD increment consumption.

3) A decrease is creditable only to the extent that it is "federally-enforceable" from the moment that the actual construction begins on the proposed modification to the source. The decrease

must occur before the proposed emissions increase occurs. An increase occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period not to exceed 180 days.

4) A decrease is creditable only to the extent that it has the same health and welfare significance as the proposed increase from the source.

5) A source cannot take credit for a decrease that it has had to make, or will have to make, in order to bring an emissions unit into compliance.

6) A source cannot take credit for an emissions reduction from potential emissions from an emissions unit which was permitted but never built or operated.

Step 5 Determine, on a pollutant-by-pollutant basis, the amount of each contemporaneous and creditable emissions increase and decrease.

An emissions increase is the amount by which the new level of "actual emissions" at the emissions unit exceeds the old level. The old level of "actual emissions" is that which prevailed just prior (i.e., prior 2 year average) to the physical or operational change at that unit which caused the increase. The new level is that which prevails just after the change. In most cases, the old level is calculated from the unit's actual operating data from a 2 year period which directly preceded the physical change. The new "actual emissions" level us the lower of the unit's "potential" or "allowable" emissions after the change. In other words, a contemporaneous emission increase is calculated as the positive difference between an emissions unit's potential to emit just after a physical or operation change at that unit (not the unit's current actual emissions) and the unit's actual emissions just prior to the change.

An emissions decrease is the amount by which the old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of "actual" emissions. Like emissions increases, the old level is calculated from the unit's actual operating data from a 2 year period which preceded the decrease, and the new emissions level will be the lower of the unit's "potential" or "allowable" emissions after the change.

Figure A-2 shows a example of how old and new actual S02 emissions levels are established for an existing emissions unit at a source. The applicant met with the reviewing agency in January 1988, proposing to commence construction on a new emissions unit in mid-1988. The contemporaneous time frame in this case is from mid-1983 (using EPA's 5-year definition) to the expected date of the new boiler start-up, about January 1990.

In mid-1984 an existing boiler switched to a low sulfur fuel oil. The applicant wishes to use the fuel switch as a netting credit. The time period for establishing the old S02 emissions level for the fuel switch is the 2 year period preceding the change [mid-1982 to mid-1984, when emissions were 600 tpy (mid-1982 through mid-1983) and 500 tpy (mid-1982 through mid-1983)]. The new S02 emissions level, 300 tpy, is established by the new allowable emissions level (which will be made federally-enforceable). The old level of emissions is 550 tpy (the average of 600 tpy and 500 tpy). Thus, if this is the only existing S02 emissions unit at the source, a decrease of 250 tpy S02 emissions (550 tpy minus 300 tpy) is creditable towards the emissions proposed for the new boiler. This example assumes that the reduction meets all other applicable criteria for a creditable emissions decrease.

Step 6 ***Sum all contemporaneous and creditable increases and decreases with the increase from the proposed modification to determine if a significant net emissions increase will occur.***

The proposed project is subject to PSD review for each regulated pollutant for which the sum of all creditable emissions increases and decreases results in a significant net emissions increase.

If available, the applicant may consider proposing additional prospective and creditable emissions reductions sufficient to provide for a less than significant net emissions increase at the source and thus avoid PSD review. These reductions can be achieved through either application of emissions controls or placing restrictions on the operation of existing emissions units. These additional reductions would be added to the sum of all other creditable increases and decreases. As with all contemporaneous emissions reductions, these additional decreases must be based on actual emissions changes, federally-enforceable prior to the commencement of construction and occur before the new unit begins operation. They must also affect the allowable PSD increment, where applicable.

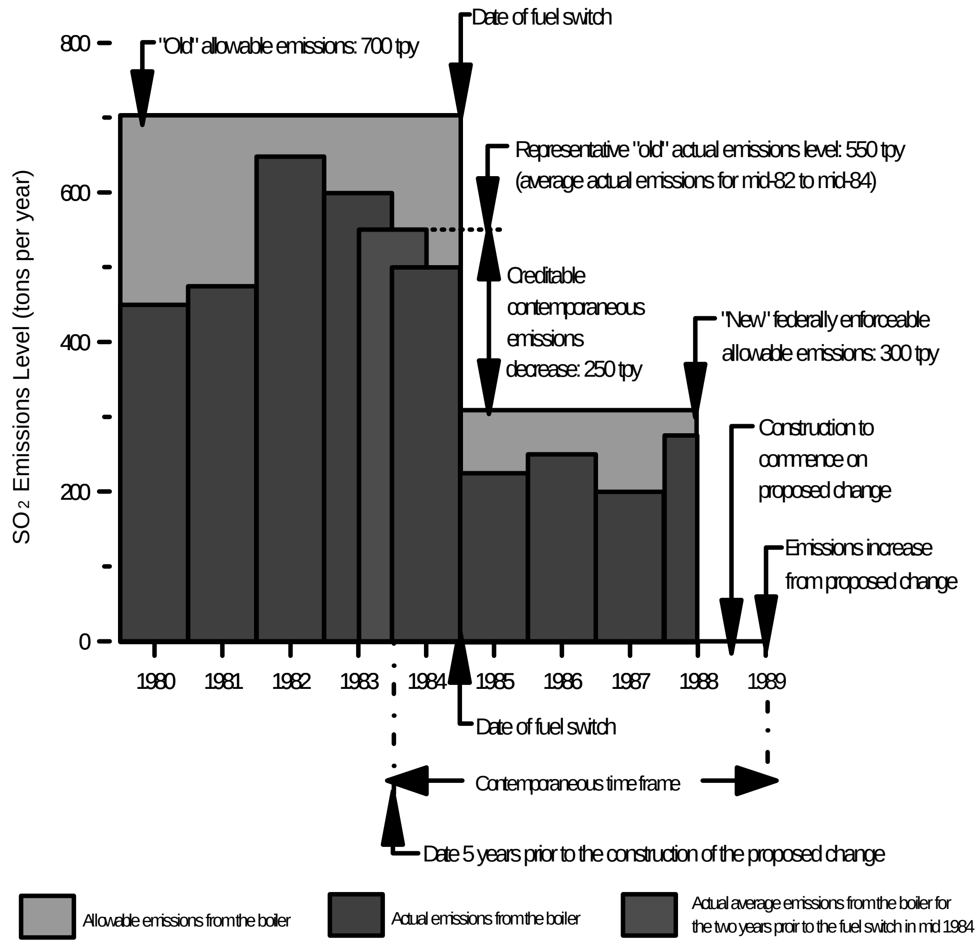

Figure A-2. Establishing "Old" and "New" Representative Actual SO_2 Emissions

III.B.6. NETTING EXAMPLE

An existing source has informed the local air pollution control agency that they are planning to construct a new emissions unit "G". The existing source is a major source and the construction of unit G will constitute a modification to the source. Unit G will be capable of emitting 80 tons per year (tpy) of the pollutant after installation of controls. The PSD significant emissions level for the pollutant in question is 40 tpy. Existing emissions units "A" and "B" at the source are presently permitted at 150 tpy each. The applicant has proposed to limit the operation of units A and B, in order to net out of PSD review, to 7056 hours per year (42 weeks) by accepting federally-enforceable conditions. The applicant has calculated that there will be an emissions reduction of -29.2 tpy [150 - 150x(7056/8760)] per unit for a total reduction of 58.4 tpy. Thus, the net emissions increase, as calculated by the applicant, will be +21.6 tpy (80-58.36). The applicant proposes to net out of PSD review citing the +21.6 tpy increase as less than the applicable 40 tpy PSD significance level for the pollutant.

The reviewing agency informed the source that 1) the emissions reductions being claimed from units A and B must be based on the prior actual emissions, not their allowable emissions and (2) because the increase from the modification will be greater than significant, <u>all</u> contemporaneous changes must be accounted for (not just proposed decreases) in order to determine the net emission change at the source.

To verify if, indeed, the source will be able to net out of PSD review, the reviewing agency requested information on the other emissions points at the source, including their actual monthly emissions. For illustrative purposes, the actual annual emissions of the pollutant in question from the existing emissions points (in this example all emissions points are associated with an emissions unit) are given as follows:

	Actual Emissions (tpy)					
Year	Unit A	Unit B	Unit C	Unit D	Unit E	Unit F
1983	70	130	60	85	50	0
1984	75	130	75	75	60	0
1985	80	150	65	80	65	0
1986	110	90	0	0	70	0
1987	115	85	0	0	75	75
1988	105	75	0	0	65	70
1989	90	90	0	0	60	65

The applicant's response indicates that units A and B will not be physically modified. However, the information does show that the modification will result in the removal of a bottleneck at the plant and that the proposed modification will result in an increase in the operation of these units.

The PSD baseline for the pollutant was triggered in 1978. The history of the emissions units at the source is as follows:

Emissions Unit(s)	History
A and B	Built in 1972 and still operational
C and D	Built in 1972 and retired from operation 01/86
E	Built in 1972 and still operational
F	PSD permitted unit; construction commenced 01/86 and the unit became operational on 01/87
G	New modification; construction scheduled to commence 01/90 and the unit is expected to be operational on 01/92

The contemporaneous period extends from 01/85 (5 years prior to 01/90, the projected construction date of the modification) until 01/92 (the date the emissions increase from the modification). The net emissions change at the source can be formulated in terms of the sum of the unit-by-unit emissions changes which are creditable and contemporaneous with the planned modification. Emission changes that are not associated with physical/ operational changes are not considered.

In assessing the creditable contemporaneous changes the permit agency considered the following (all numbers are in tpy):

- Potential to emit is used for a new unit. The new unit will receive a federally-enforceable permit restricting allowable emissions to 80 tpy, which then becomes its potential to emit. Therefore, the new unit represents an increase of +80.

- Even though units A and B will not be modified, their emissions are expected to increase as a result of the modification and the anticipated increase must be included as part of the increase from the proposed modification. The emissions change for these units is based on their allowable emissions after the change minus their current actual emissions. Current actual emissions are based on the average emissions over the last 2 years. [Note that only the operations of exiting units A and B are expected to be affected by the modification.] The emissions changes at A and B are calculated as follows:

Unit A's change = +23.3

{new allowable [150x(7056/8760)] - old actual [(105+90)/2]}

Unit B's change = +38.3

{new allowable [150x(7056/8760)] - old actual [(75+90)/2]}

The federally-enforceable restriction on the hours of operation for units A and B act to reduce the amount of the emissions increase at the units due to the modification. However, contrary to the applicant's analysis, the restrictions did not restrict the units' emissions sufficiently to prevent an actual emissions increase.

- The emissions increase from unit F was permitted under PSD. Therefore, having been "relied upon" in the issuance of a PSD permit which is still in effect, the permitted emissions increase is not creditable and cannot be used in the netting equation.

- The operation of unit E is not projected to be affected by the proposed modification. It has not undergone any physical or operational change during the contemporaneous period which would otherwise trigger a creditable emissions change at the unit. Consequently, unit E's emissions are not considered for netting purposes by the reviewing agency.

- The retirement (a physical/operational change) of units C and D occurred within the contemporaneous period and may provide creditable decreases for the applicant. However, if the retirement of the units was relied upon in the issuance of the PSD permit for unit F (e.g, if the emissions of units C or D were modeled at zero in the PSD application) then the reductions would not be creditable. If they were not modeled as retired (zero emissions), then the reduction would be available as an emissions reduction. The reduction credit would be based on the last 2 years of actual data prior to retirement. As with all reductions, to be creditable the retirement of the units must be made federally-enforceable prior to construction of the modification to and start-up of the source. Upon checking the PSD permit application for unit F, the reviewing agency determined that units C and D were not considered retired and their emissions were included in the ambient impact analysis for unit F. Consequently, the emissions reduction from the retirement of unit C and D (should the reductions be made federally-enforceable) was determined as followed:

Unit C's change = -70

{its new allowable [0] - its old actual [(75+65)/2]}

Unit D's change = -77.5

{its new allowable [0] - its old actual [(75+80)/2]}

- The netting transaction would not cause or contribute to a violation of the applicable PSD increment or ambient standards.

The applicant, however, is only willing to accept federally-enforceable conditions on the retirement of unit C. Unit D is to be kept as a standby unit and the applicant is unwilling to have its potential operation limited. Consequently, the reduction in emissions at unit D is not creditable.

The net contemporaneous emissions change at the source is calculated by the reviewing agency as follows:

Emissions Change (tpy)

+80.0 increase from unit G.
+23.3 increase at A from modification at source.
+38.8 increase at B from modification at source.
-70.0 creditable decrease from retirement of unit C
+72.1 total contemporaneous net emissions increase at the source.

The +72.1 tpy net increase is greater than the +40 tpy PSD significance level; consequently the proposed modification is subject to PSD review for that pollutant.

If the applicant is willing to agree to federally-enforceable conditions limiting the allowable emissions from unit D (but not necessarily requiring the unit's permanent retirement), a sufficient reduction may be available to net unit G out of a PSD review. For example, the applicant could agree to accept federally-enforceable conditions limiting the operation of unit D to 672 hours a year (4 weeks), which (for illustrative purposes) equates to an allowable emissions of 15 tpy. The creditable reduction from the unit D would then amount to -62.5 tpy (-77.5 +15). This brings the total contemporaneous net emissions change for the proposed modification to +9.6 tpy (+72.1 - 62.5). The construction of Unit G would then not be considered a major modification subject to PSD review. It is important to note, however, that if unit D is permanently taken out of service after January 1991 and had not operated in the interim, the source would not be allowed an emissions reduction credit because there would have been no actual emissions decrease during the contemporaneous period. In addition, if the source later requests removal of restrictions on units which allowed unit G to net out of review, unit G then becomes subject to PSD review as though construction had not yet commenced.

IV. GENERAL EXEMPTIONS

IV.A. SOURCES AND MODIFICATIONS AFTER AUGUST 7,1980

Certain sources may be exempted from PSD review or certain PSD requirements. Nonprofit health or educational sources that would otherwise be subject to PSD review can be exempted if requested by the Governor of the State in which they are located. A portable, major stationary source that has previously received a PSD permit and is to be relocated is exempt from a second PSD review if (1) emissions at the new location will not exceed previously allowed emission rates, (2) the emissions at the new location are temporary, and (3) the source will not, because of its new location, adversely affect a Class I area or contribute to any known increment or national ambient air quality standard (NAAQS) violation. However, the source must provide reasonable advance notice to the reviewing authority.

IV.B. SOURCES CONSTRUCTED PRIOR TO AUGUST 7,1980

The 1980 PSD regulations do not apply to certain sources affected by previous PSD regulations. For example, sources for which construction began before August 7, 1977 are exempt from the 1980 PSD regulations and are instead reviewed for applicability under the PSD regulations as they existed before August 7, 1977. Several exemptions also exist for sources for which construction began after August 7, 1977, but before the August 7, 1980 promulgation of the PSD regulations (45 FR 52676). These exemptions and the criteria associated nonapplicability are detailed in paragraph (i) of 40 CFR 52.21.

CHAPTER B

BEST AVAILABLE CONTROL TECHNOLOGY

I. INTRODUCTION

Any major stationary source or major modification subject to PSD must conduct an analysis to ensure the application of best available control technology (BACT). The requirement to conduct a BACT analysis and determination is set forth in section 165(a)(4) of the Clean Air Act (Act), in federal regulations at 40 CFR 52.21(j), in regulations setting forth the requirements for State implementation plan approval of a State PSD program at 40 CFR 51.166(j), and in the SIP's of the various States at 40 CFR Part 52, Subpart A - Subpart FFF. The BACT requirement is defined as:

> "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."

During each BACT analysis, which is done on a case-by-case basis, the reviewing authority evaluates the energy, environmental, economic and other costs associated with each alternative technology, and the benefit of reduced emissions that the technology would bring. The reviewing authority then specifies an emissions limitation for the source that reflects the maximum degree of reduction achievable for each pollutant regulated under the Act. In no event can a technology be recommended which would not meet any applicable standard of performance under 40 CFR Parts 60 (New Source Performance Standards) and 61 (National Emission Standards for Hazardous Air Pollutants).

In addition, if the reviewing authority determines that there is no economically reasonable or technologically feasible way to accurately measure the emissions, and hence to impose an enforceable emissions standard, it may require the source to use design, alternative equipment, work practices or operational standards to reduce emissions of the pollutant to the maximum extent.

On December 1, 1987, the EPA Assistant Administrator for Air and Radiation issued a memorandum that implemented certain program initiatives designed to improve the effectiveness of the NSR programs within the confines of existing regulations and state implementation plans. Among these was the "top-down" method for determining best available control technology (BACT).

In brief, the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent--or "top"--alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

The purpose of this chapter is to provide a detailed description of the top-down method in order to assist permitting authorities and PSD applicants in conducting BACT analyses.

II. BACT APPLICABILITY

The BACT requirement applies to each individual new or modified affected emissions unit and pollutant emitting activity at which a net emissions increase would occur. Individual BACT determinations are performed for each pollutant subject to a PSD review emitted from the same emission unit. Consequently, the BACT determination must separately address, for each regulated pollutant with a significant emissions increase at the source, air pollution controls for each emissions unit or pollutant emitting activity subject to review.

III. A STEP BY STEP SUMMARY OF THE TOP-DOWN PROCESS

Table B-1 shows the five basic steps of the top-down procedure, including some of the key elements associated with each of the individual steps. A brief description of each step follows.

III.A. STEP 1--IDENTIFY ALL CONTROL TECHNOLOGIES

The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant. This includes technologies employed outside of the United States. As discussed later, in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives. The control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technologies. Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and must also be included as control alternatives and usually represent the top alternative.

In the course of the BACT analysis, one or more of the options may be eliminated from consideration because they are demonstrated to be technically infeasible or have unacceptable energy, economic, and environmental impacts on a case-by-case (or site-specific) basis. However, at the outset, applicants

TABLE B-1. - KEY STEPS IN THE "TOP-DOWN" BACT PROCESS

STEP 1: IDENTIFY ALL CONTROL TECHNOLOGIES.

- LIST is comprehensive (LAER included).

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS.

- A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS.

Should include:

- control effectiveness (percent pollutant removed);
- expected emission rate (tons per year);
- expected emission reduction (tons per year);
- energy impacts (BTU, kWh);
- environmental impacts (other media and the emissions of toxic and hazardous air emissions); and
- economic impacts (total cost effectiveness, incremental cost effectiveness).

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS.

- Case-by-case consideration of energy, environmental, and economic impacts.
- If top option is not selected as BACT, evaluate next most effective control option.

STEP 5: SELECT BACT

- Most effective option not rejected is BACT.

should initially identify all control options with potential application to the emissions unit under review.

III.B. STEP 2--ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

In the second step, the technical feasibility of the control options identified in step one is evaluated with respect to the source-specific (or emissions unit-specific) factors. A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

For example, in cases where the level of control in a permit is not expected to be achieved in practice (e.g., a source has received a permit but the project was cancelled, or every operating source at that permitted level has been physically unable to achieve compliance with the limit), and supporting documentation showing why such limits are not technically feasible is provided, the level of control (but not necessarily the technology) may be eliminated from further consideration. However, a permit requiring the application of a certain technology or emission limit to be achieved for such technology usually is sufficient justification to assume the technical feasibility of that technology or emission limit.

III.C. STEP 3--RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

In step 3, all remaining control alternatives not eliminated in step 2 are ranked and then listed in order of over all control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis. The list should present the array of control technology alternatives and should include the following types of information:

- ! control efficiencies (percent pollutant removed);
- ! expected emission rate (tons per year, pounds per hour);
- ! expected emissions reduction (tons per year);
- ! economic impacts (cost effectiveness);
- ! environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants);
- ! energy impacts.

However, an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document that the control option chosen is, indeed, the top, and review for collateral environmental impacts.

III.D. STEP 4--EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

After the identification of available and technically feasible control technology options, the energy, environmental, and economic impacts are considered to arrive at the final level of control. At this point the analysis presents the associated impacts of the control option in the listing. For each option the applicant is responsible for presenting an objective evaluation of each impact. Both beneficial and adverse impacts should be discussed and, where possible, quantified. In general, the BACT analysis should focus on the direct impact of the control alternative.

If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT.

III.E. STEP 5--SELECT BACT

The most effective control option not eliminated in step 4 is proposed as BACT for the pollutant and emission unit under review.

IV. TOP-DOWN ANALYSIS DETAILED PROCEDURE

IV.A. IDENTIFY ALTERNATIVE EMISSION CONTROL TECHNIQUES (STEP 1)

The objective in step 1 is to identify all control options with potential application to the source and pollutant under evaluation. Later, one or more of these options may be eliminated from consideration because they are determined to be technically infeasible or to have unacceptable energy, environmental or economic impacts.

Each new or modified emission unit (or logical grouping of new or modified emission units) subject to PSD is required to undergo BACT review. BACT decisions should be made on the information presented in the BACT analysis, including the degree to which effective control alternatives were identified and evaluated. Potentially applicable control alternatives can be categorized in three ways.

- ***Inherently Lower-Emitting Processes/Practices***, including the use of materials and production processes and work practices that prevent emissions and result in lower "production-specific" emissions; and
- ***Add-on Controls***, such as scrubbers, fabric filters, thermal oxidizers and other devices that control and reduce emissions after they are produced.
- ***Combinations of Inherently Lower Emitting Processes and Add-on Controls***. For example, the application of combustion and post-combustion controls to reduce NOx emissions at a gas-fired turbine.

The top-down BACT analysis should consider potentially applicable control techniques from all three categories. Lower-polluting processes should be considered based on demonstrations made on the basis of manufacturing identical or similar products from identical or similar raw materials or fuels. Add-on controls, on the other hand, should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream. Thus, candidate add-on controls may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emissions unit undergoing BACT review.

IV.A.1. DEMONSTRATED AND TRANSFERABLE TECHNOLOGIES

Applicants are expected to identify all demonstrated and potentially applicable control technology alternatives. Information sources to consider include:

- EPA's BACT/LAER Clearinghouse and Control Technology Center;
- Best Available Control Technology Guideline - South Coast Air Quality Management District;
- control technology vendors;
- Federal/State/Local new source review permits and associated inspection/performance test reports;
- environmental consultants;
- technical journals, reports and newsletters (e.g., JAPCA and the McIvaine reports), air pollution control seminars; and
- EPA's New Source Review (NSR) bulletin board.

The applicant should make a good faith effort to compile appropriate information from available information sources, including any sources specified as necessary by the permit agency. The permit agency should review the background search and resulting list of control alternatives presented by the applicant to check that it is complete and comprehensive.

In identifying control technologies, the applicant needs to survey the range of potentially available control options. Opportunities for technology transfer lie where a control technology has been applied at source categories other than the source under consideration. Such opportunities should be identified. Also, technologies in application outside the United States to the extent that the technologies have been successfully demonstrated in practice on full scale operations. Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice.

To satisfy the legislative requirements of BACT, EPA believes that the applicant must focus on technologies with a demonstrated potential to achieve the highest levels of control. For example, control options incapable of meeting an applicable New Source Performance Standard (NSPS) or State Implementation Plan (SIP) limit would not meet the definition of BACT under any circumstances. The applicant does not need to consider them in the BACT analysis.

The fact that a NSPS for a source category does not require a certain level of control or particular control technology does not preclude its consideration in the top-down BACT analysis. For example, post combustion NOx controls are not required under the Subpart GG of the NSPS for Stationary Gas Turbines. However, such controls must still be considered available technologies for the BACT selection process and be considered in the BACT analysis. An NSPS simply defines the minimal level of control to be considered in the BACT analysis. The fact that a more stringent technology was not selected for a NSPS (or that a pollutant is not regulated by an NSPS) does not exclude that control alternative or technology as a BACT candidate. When developing a list of possible BACT alternatives, the only reason for comparing control options to an NSPS is to determine whether the control option would result in an emissions level less stringent than the NSPS. If so, the option is unacceptable.

IV.A.2. INNOVATIVE TECHNOLOGIES

Although not required in step 1, the applicant may also evaluate and propose innovative technologies as BACT. To be considered innovative, a control technique must meet the provisions of 40 CFR 52.21(b)(19) or, where appropriate, the applicable SIP definition. In essence, if a developing technology has the potential to achieve a more stringent emissions level than otherwise would constitute BACT or the same level at a lower cost, it may be proposed as an innovative control technology. Innovative technologies are distinguished from technology transfer BACT candidates in that an innovative technology is still under development and has not been demonstrated in a commercial application on identical or similar emission units. In certain instances, the distinction between innovative and transferable technology may not be straightforward. In these cases, it is recommended that the permit agency consult with EPA prior to proceeding with the issuance of an innovative control technology waiver.

In the past only a limited number of innovative control technology waivers for a specific control technology have been approved. As a practical matter, if a waiver has been granted to a similar source for the same technology, granting of additional waivers to similar sources is highly unlikely since the subsequent applicants are no longer "innovative".

IV.A.3. CONSIDERATION OF INHERENTLY LOWER POLLUTING PROCESSES/PRACTICES

Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives. For example, applicants proposing to construct a coal-fired electric generator, have not been required by EPA as part of a BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product (in this case electricity). However, this is an aspect of the PSD permitting process in which states have the discretion to engage in a broader analysis if they so desire. Thus, a gas turbine normally would not be included in the list of control alternatives for a coal-fired boiler. However, there may be instances where, in the permit authority's judgment, the consideration of alternative production processes is warranted and appropriate for consideration in the BACT analysis. A production process is defined in terms of its physical and chemical unit operations used to produce the desired product from a specified set of raw materials. In such cases, the permit agency may require the applicant to include the inherently lower-polluting process in the list of BACT candidates.

In many cases, a given production process or emissions unit can be made to be inherently less polluting (e.g; the use of water-based versus solvent based paints in a coating operation or a coal-fired boiler designed to have a low emission factor for NOx). In such cases the ability of design considerations to make the process inherently less polluting must be considered as a control alternative for the source. Inherently lower-polluting processes/practice are usually more environmentally effective because of lower amounts of solid wastes and waste water than are generated with add-on controls. These factors are considered in the cost, energy and environmental impacts analyses in step 4 to determine the appropriateness of the additional add-on option.

Combinations of inherently lower-polluting processes/practices (or a process made to be inherently less polluting) and add-on controls are likely to yield more effective means of emissions control than either approach alone. Therefore, the option to utilize a inherently lower-polluting process does not, in and of itself, mean that no additional add-on controls need be included in the BACT analysis. These combinations should be identified in step 1 of the top down process for evaluation in subsequent steps.

IV.A.4. EXAMPLE

The process of identifying control technology alternatives (step 1 in the top-down BACT process) is illustrated in the following hypothetical example.

Description of Source

A PSD applicant proposes to install automated surface coating process equipment consisting of a dip-tank priming stage followed by a two-step spray application and bake-on enamel finish coat. The product is a specialized electronics component (resistor) with strict resistance property specifications that restrict the types of coatings that may be employed.

List of Control Options

The source is not covered by an applicable NSPS. A review of the BACT/LAER Clearinghouse and other appropriate references indicates the following control options may be applicable:

Option #1: **water-based primer and finish coat;**

[The water-based coatings have never been used in applications similar to this.]

Option #2: **low-VOC solvent/high solids coating for primer and finish coat;**

[The high solids/low VOC solvent coatings have recently been applied with success with similar products (e.g., other types of electrical components).]

Option #3: **electrostatic spray application to enhance coating transfer efficiency;** and

[Electrostatically enhanced coating application has been applied elsewhere on a clearly similar operation.]

Option #4: **emissions capture with add-on control via incineration or carbon adsorber equipment.**

[The VOC capture and control option (incineration or carbon adsorber) has been used in many cases involving the coating of different products and the emission stream characteristics are similar to the proposed resistor coating process and is identified as an option available through technology transfer.]

Since the low-solvent coating, electrostatically enhanced application, and ventilation with add-on control options may reasonably be considered for use in combination to achieve greater emissions reduction efficiency, a total of eight control options are eligible for further consideration. The options include each of the four options listed above and the following four combinations of techniques:

Option #5: **low-solvent coating with electrostatic applications without ventilation and add-on controls;**

Option #6: **low-solvent coating without electrostatic applications with ventilation and add-on controls;**

Option #7: **electrostatic application with add-on control;** and

Option #8: **a combination of all three technologies.**

A "no control" option also was identified but eliminated because the applicant's State regulations require at least a 75 percent reduction in VOC emissions for a source of this size. Because "no control" would not meet the State regulations it could not be BACT and, therefore, was not listed for consideration in the BACT analysis.

Summary of Key Points

The example illustrates several key guidelines for identifying control options. These include:

! All available control techniques must be considered in the BACT analysis.

! Technology transfer must be considered in identifying control options. The fact that a control option has never been applied to process emission units similar or identical to that proposed does not mean it can be ignored in the BACT analysis if the potential for its application exists.

! Combinations of techniques should be considered to the extent they result in more effective means of achieving stringent emissions levels represented by the "top" alternative, particularly if the "top" alternative is eliminated.

IV.B. TECHNICAL FEASIBILITY ANALYSIS (STEP 2)

In step 2, the technical feasibility of the control options identified in step 1 is evaluated. This step should be straightforward for control technologies that are demonstrated--if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible. For control technologies that are not demonstrated in the sense indicated above, the analysis is somewhat more involved.

Two key concepts are important in determining whether an undemonstrated technology is feasible: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

Availability in this context is further explained using the following process commonly used for bringing a control technology concept to reality as a commercial product:

! concept stage;

! research and patenting;

! bench scale or laboratory testing;

! pilot scale testing;

! licensing and commercial demonstration; and

! commercial sales.

A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development. A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in the pilot scale testing stages of development would not be considered available for BACT review. An exception would be if the technology were proposed and permitted under the qualifications of an innovative control device consistent with the provisions of 40 CFR 52.21(v) or, where appropriate, the applicable SIP.

Commercial availability by itself, however, is not necessarily sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or "applicable" to the source type under consideration.

Technical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on an existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary.

For process-type control alternatives the decision of whether or not it is applicable to the source in question would have to be based on an assessment of the similarities and differences between the proposed source and other sources to which the process technique had been applied previously. Absent an explanation of unusual circumstances by the applicant showing why a particular process cannot be used on the proposed source the review authority may presume it is technically feasible.

In practice, decisions about technical feasibility are within the purview of the review authority. Further, a presumption of technical feasibility may be made by the review authority based solely on technology transfer. For example, in the case of add-on controls, decisions of this type would be made by comparing the physical and chemical characteristics of the exhaust gas stream from the unit under review to those of the unit from which the technology is to be transferred. Unless significant differences between source types exist that are pertinent to the successful operation of the control device, the control option is presumed to be technically feasible unless the source can present information to the contrary.

Within the context of the top-down procedure, an applicant addresses the issue of technical feasibility in asserting that a control option identified in Step 1 is technically infeasible. In this instance, the applicant should make a factual demonstration of infeasibility based on commercial unavailability and/or unusual circumstances which exist with application of the control to the applicant's emission units. Generally, such a demonstration would involve an evaluation of the pollutant-bearing gas stream characteristics and the capabilities of the technology. Also a showing of unresolvable technical difficulty with applying the control would constitute a showing of technical infeasibility (e.g., size of the unit, location of the proposed site, and operating problems related to specific circumstances of the source). Where the resolution of technical difficulties is a matter of cost, the applicant should consider the technology as technically feasible. The economic feasibility of a control alternative is reviewed in the economic impacts portion of the BACT selection process.

A demonstration of technical infeasibility is based on a technical assessment considering physical, chemical and engineering principles and/or empirical data showing that the technology would not work on the emissions unit under review, or that unresolvable technical difficulties would preclude the successful deployment of the technique. Physical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility. However, the cost of such modifications can be considered in estimating cost and economic impacts which, in turn, may form the basis for eliminating a control technology (see later discussion at V.D.2).

Vendor guarantees may provide an indication of commercial availability and the technical feasibility of a control technique and could contribute to a determination of technical feasibility or technical infeasibility, depending on circumstances. However, EPA does not consider a vendor guarantee alone to be sufficient justification that a control option will work. Conversely, lack of a vendor guarantee by itself does not present sufficient justification that a control option or an emissions limit is technically infeasible. Generally, decisions about technical feasibility will be based on chemical, and engineering analyses (as discussed above) in conjunction with information about vendor guarantees.

A possible outcome of the top-down BACT procedures discussed in this document is the evaluation of multiple control technology alternatives which result in essentially equivalent emissions. It is not EPA's intent to encourage evaluation of unnecessarily large numbers of control alternatives for every emissions unit. Consequently, judgment should be used in deciding what alternatives will be evaluated in detail in the impacts analysis (Step 4) of the top-down procedure discussed in a later section. For example, if two or more control techniques result in control levels that are essentially identical considering the uncertainties of emissions factors and other parameters pertinent to estimating performance, the source may wish to point this out and make a case for evaluation and use only of the less costly of these options. The scope of the BACT analysis should be narrowed in this way only if there is a negligible difference in emissions and collateral environmental impacts between control alternatives. Such cases should be discussed with the reviewing agency before a control alternative is dismissed at this point in the BACT analysis due to such considerations.

It is encouraged that judgments of this type be discussed during a preapplication meeting between the applicant and the review authority. In this way, the applicant can be better assured that the analysis to be conducted will meet BACT requirements. The appropriate time to hold such a meeting during the analysis is following the completion of the control hierarchy discussed in the next section.

Summary of Key Points

In summary, important points to remember in assessing technical feasibility of control alternatives include:

! A control technology that is "demonstrated" for a given type or class of sources is assumed to be technically feasible unless source-specific factors exist and are documented to justify technical infeasibility.

! Technical feasibility of technology transfer control candidates generally is assessed based on an evaluation of pollutant-bearing gas stream characteristics for the proposed source and other source types to which the control had been applied previously.

! Innovative controls that have not been demonstrated on any source type similar to the proposed source need not be considered in the BACT analysis.

! The applicant is responsible for providing a basis for assessing technical feasibility or infeasibility and the review authority is responsible for the decision on what is and is not technically feasible.

IV.C. RANKING THE TECHNICALLY FEASIBLE ALTERNATIVES TO ESTABLISH A CONTROL HIERARCHY (STEP 3)

Step 3 involves ranking all the technically feasible control alternatives which have been previously identified in Step 2. For the regulated pollutant and emissions unit under review, the control alternatives are ranked-ordered from the most to the least effective in terms of emission reduction potential. Later, once the control technology is determined, the focus shifts to the specific limits to be met by the source.

Two key issues that must be addressed in this process include:

- What common units should be used to compare emissions performance levels among options?
- How should control techniques that can operate over a wide range of emission performance levels (e.g., scrubbers, etc.) be considered in the analysis?

IV.C.1. CHOICE OF UNITS OF EMISSIONS PERFORMANCE TO COMPARE LEVELS AMONGST CONTROL OPTIONS

In general, this issue arises when comparing inherently lower-polluting processes to one another or to add-on controls. For example, direct comparison of powdered (and low-VOC) coatings and vapor recovery and control systems at a metal furniture finishing operation is difficult because of the different units of measure for their effectiveness. In such cases, it is generally most effective to express emissions performance as an average steady state emissions level per unit of product produced or processed. Examples are:

- pounds VOC emission per gallons of solids applied,
- pounds PM emission per ton of cement produced,
- pounds SO2 emissions per million Btu heat input, and
- pounds SO2 emission per kilowatt of electric power produced,

Calculating annual emissions levels (tons/yr) using these units becomes straightforward once the projected annual production or processing rates are known. The result is an estimate of the annual pollutant emissions that the source or emissions unit will emit. Annual "potential" emission projections are calculated using the source's maximum design capacity and full year round operation (8760 hours), unless the final permit is to include federally enforceable conditions restricting the source's capacity or hours of operation. However, emissions estimates used for the purpose of calculating and comparing the cost effectiveness of a control option are based on a different approach (see section V.D.2.b. COST EFFECTIVENESS).

IV.C.2. CONTROL TECHNIQUES WITH A WIDE RANGE OF EMISSIONS PERFORMANCE LEVELS

The objective of the top-down BACT analysis is to not only identify the best control technology, but also a corresponding performance level (or in some cases performance range) for that technology considering source-specific factors. Many control techniques, including both add-on controls and inherently lower polluting processes can perform at a wide range of levels. Scrubbers, high and low efficiency electrostatic precipitators (ESPs), and low-VOC coatings are examples of just a few. It is not the EPA's intention to require analysis of each possible level of efficiency for a control technique, as such an analysis would result in a large number of options. Rather, the applicant should use the most recent regulatory decisions and performance data for identifying the emissions performance level(s) to be evaluated in all cases.

The EPA does not expect an applicant to necessarily accept an emission limit as BACT solely because it was required previously of a similar source type. While the most effective level of control must be considered in the

BACT analysis, different levels of control for a given control alternative can be considered.[1] For example, the consideration of a lower level of control for a given technology may be warranted in cases where past decisions involved different source types. The evaluation of an alternative control level can also be considered where the applicant can demonstrate to the satisfaction of the permit agency demonstrate that other considerations show the need to evaluate the control alternative at a lower level of effectiveness.

Manufacturer's data, engineering estimates and the experience of other sources provide the basis for determining achievable limits. Consequently, in assessing the capability of the control alternative, latitude exists to consider any special circumstances pertinent to the specific source under review, or regarding the prior application of the control alternative. However, the basis for choosing the alternate level (or range) of control in the BACT analysis must be documented in the application. In the absence of a showing of differences between the proposed source and previously permitted sources achieving lower emissions limits, the permit agency should conclude that the lower emissions limit is representative for that control alternative.

In summary, when reviewing a control technology with a wide range of emission performance levels, it is presumed that the source can achieve the same emission reduction level as another source unless the applicant demonstrates that there are source-specific factors or other relevant information that provide a technical, economic, energy or environmental justification to do otherwise. Also, a control technology that has been eliminated as having an adverse economic impact at its highest level of performance, may be acceptable at a lesser level of performance. For example, this can occur when the cost effectiveness of a control technology at its

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[1] In reviewing the BACT submittal by a source the permit agency may determine that an applicant should consider a control technology alternative otherwise eliminated by the applicant, if the operation of that control technology at a lower level of control (but still higher than the next control alternative. For example, while scrubber operating at 98% efficiency may be eliminated as BACT by the applicant due to source specific economic considerations, the scrubber operating in the 90% to 95% efficiency range may not have an adverse economic impact.

highest level of performance greatly exceeds the cost of that control technology at a somewhat lower level (or range) of performance.

IV.C.3. ESTABLISHMENT OF THE CONTROL OPTIONS HIERARCHY

After determining the emissions performance levels (in common units) of each control technology option identified in Step 2, a hierarchy is established that places at the "top" the control technology option that achieves the lowest emissions level. Each other control option is then placed after the "top" in the hierarchy by its respective emissions performance level, ranked from lowest emissions to highest emissions (most effective to least stringent effective emissions control alternative).

From the hierarchy of control alternatives the applicant should develop a chart (or charts) displaying the control hierarchy and, where applicable,:

- expected emission rate (tons per year, pounds per hour);
- emissions performance level (e.g., percent pollutant removed, emissions per unit product, lb/MMbtu, ppm);
- expected emissions reduction (tons per year);
- economic impacts (total annualized costs, cost effectiveness, incremental cost effectiveness);
- environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and the relative ability of each control alternative to control emissions of toxic or hazardous air contaminants);
- energy impacts (indicate any significant energy benefits or disadvantages).

This should be done for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis. The chart is used in comparing the control alternatives during step 4 of the BACT selection process. Some sample charts are displayed in Table B-2 and Table B-3. Completed sample charts accompany the example BACT analyses provided in section VI.

At this point, it is recommended that the applicant contact the reviewing agency to determine whether the agency feels that any other applicable control alternative should be evaluated or if any issues require special attention in the BACT selection process.

IV.D. THE BACT SELECTION PROCESS (STEP 4)

After identifying and listing the available control options the next step is the determination of the energy, environmental, and economic impacts of each option and the selection of the final level of control. The applicant is responsible for presenting an evaluation of each impact along with appropriate supporting information. Consequently, both beneficial and adverse impacts should be discussed and, where possible, quantified. In general, the BACT analysis should focus on the direct impact of the control alternative.

Step 4 validates the suitability of the top control option in the listing for selection as BACT, or provides clear justification why the top candidate is inappropriate as BACT. If the applicant accepts the top alternative in the listing as BACT from an economic and energy standpoint, the applicant proceeds to consider whether collateral environmental impacts (e.g., emissions of unregulated air pollutants or impacts in other media) would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate

TABLE B-2. SAMPLE BACT CONTROL HIERARCHY

Pollutant	Technology	Range of control (%)	Control level for BACT analysis (%)	Emissions limit
SO_2	First Alternative	80-95	95	15 ppm
	Second Alternative	80-95	90	30 ppm
	Third Alternative	70-85	85	45 ppm
	Fourth Alternative	40-80	75	75 ppm
	Fifth Alternative	50-85	70	90 ppm
	Baseline Alternative	-	-	-

TABLE B-3. SAMPLE SUMMARY OF TOP-DOWN BACT IMPACT ANALYSIS RESULTS

				Economic Impacts			Environmental Impacts		Energy Impacts
Pollutant/ Emissions Unit	Control alternative	Emissions (lb/hr,tpy)	Emissions reduction(a) (tpy)	Total annualized cost(b) ($/yr)	Average Cost effectiveness(c) ($/ton)	Incremental cost effectiveness(d) ($/ton)	Toxics impact(e) (Yes/No)	Adverse environmental impacts(f) (Yes/No)	Incremental increase over baseline(g) (MMBtu/yr)
NOx/Unit A	Top Alternative								
	Other Alternative(s)								
	Baseline								
NOx/Unit B	Top Alternative								
	Other Alternative(s)								
	Baseline								
SO2/Unit A	Top Alternative								
	Other Alternative(s)								
	Baseline								
SO2/Unit B	Top Alternative								
	Other Alternative(s)								
	Baseline								

(a) Emissions reduction over baseline level.
(b) Total annualized cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation) is used to express capital costs in present-day annual costs.
(c) Average Cost Effectiveness is total annualized cost for the control option divided by the emissions reductions resulting from the option.
(d) The incremental cost effectiveness is the difference in annualized cost for the control option and the next most effective control option divided by the difference in emissions reduction resulting from the respective alternatives.
(e) Toxics impact means there is a toxics impact consideration for the control alternative.
(f) Adverse environmental impact means there is an adverse environmental impact consideration with the control alternative.
(g) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline expressed in equivalent millions of Btus per year.

is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding needs to be fully documented for the public record. Then, the next most effective alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the control technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that the alternative is inappropriate as BACT.

The determination that a control alternative to be inappropriate involves a demonstration that circumstances exist at the source which distinguish it from other sources where the control alternative may have been required previously, or that argue against the transfer of technology or application of new technology. Alternately, where a control technique has been applied to only one or a very limited number of sources, the applicant can identify those characteristic(s) unique to those sources that may have made the application of the control appropriate in those case(s) but not for the source under consideration. In showing unusual circumstances, objective factors dealing with the control technology and its application should be the focus of the consideration. The specifics of the situation will determine to what extent an appropriate demonstration has been made regarding the elimination of the more effective alternative(s) as BACT. In the absence of unusual circumstance, the presumption is that sources within the same category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category.

IV.D.1. ENERGY IMPACTS ANALYSIS

Applicants should examine the energy requirements of the control technology and determine whether the use of that technology results in any significant or unusual energy penalties or benefits. A source may, for example, benefit from the combustion of a concentrated gas stream rich in volatile organic compounds; on the other hand, more often extra fuel or electricity is required to power a control device or incinerate a dilute gas stream. If such benefits or penalties exist, they should be quantified. Because energy penalties or benefits can usually be quantified in terms of additional cost or income to the source, the energy impacts analysis can, in most cases, simply be factored into the economic impacts analysis. However, certain types of control technologies have inherent energy penalties associated with their use. While these penalties should be quantified, so long as they are within the normal range for the technology in question, such penalties should not, in general, be considered adequate justification for nonuse of that technology.

Energy impacts should consider only direct energy consumption and not indirect energy impacts. For example, the applicant could estimate the direct energy impacts of the control alternative in units of energy consumption at the source (e.g., Btu, kWh, barrels of oil, tons of coal). The energy requirements of the control options should be shown in terms of total (and in certain cases also incremental) energy costs per ton of pollutant removed. These units can then be converted into dollar costs and, where appropriate, factored into the economic analysis.

As noted earlier, indirect energy impacts (such as energy to produce raw materials for construction of control equipment) generally are not considered. However, if the permit authority determines, either independently or based on a showing by the applicant, that the indirect energy impact is unusual or significant and that the impact can be well quantified, the indirect impact may be considered. The energy impact should still focus on the application of the control alternative and not a concern over general energy impacts associated with the project under review as compared to alternative projects for which a permit is not being sought, or as compared to a pollution source which the project under review would replace (e.g., it would be inappropriate to argue that a cogeneration project is more efficient in the production of electricity than the powerplant production capacity it would displace and, therefore, should not be required to spend equivalent costs for the control of the same pollutant).

The energy impact analysis may also address concerns over the use of locally scarce fuels. The designation of a scarce fuel may vary from region to region, but in general a scarce fuel is one which is in short supply locally and can be better used for alternative purposes, or one which may not be reasonably available to the source either at the present time or in the near future.

IV.D.2. COST/ECONOMIC IMPACTS ANALYSIS

Average and incremental cost effectiveness are the two economic criteria that are considered in the BACT analysis. Cost effectiveness, is the dollars per ton of pollutant emissions reduced. Incremental cost is the cost per ton reduced and should be considered in conjunction with total average effectiveness.

In the economical impacts analysis, primary consideration should be given to quantifying the cost of control and not the economic situation of the individual source. Consequently, applicants generally should not propose elimination of control alternatives on the basis of economic parameters that provide an indication of the affordability of a control alternative relative to the source. BACT is required by law. Its costs are integral to the overall cost of doing business and are not to be considered an afterthought. Consequently, for control alternatives that have been effectively employed in the same source category, the economic impact of such alternatives on the particular source under review should be not nearly as pertinent to the BACT decision making process as the average and, where appropriate, incremental cost effectiveness of the control alternative. Thus, where a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if **any,** between the application of the control technology on those other sources and the particular source under review.

Cost effectiveness (dollars per ton of pollutant reduced) values above the levels experienced by other sources of the same type and pollutant, are taken as an indication that unusual and persuasive differences exist with respect to the source under review. In addition, where the cost of a control alternative for the specific source reviewed is within the range of normal costs for that control alternative, the alternative, in certain limited circumstances, may still be eligible for elimination. To justify elimination of an alternative on these grounds, the applicant should demonstrate to the satisfaction of the permitting agency that costs of pollutant removal for the control alternative are disproportionately high when compared to the cost of control for that particular pollutant and source in recent BACT determinations. If the circumstances of the differences are adequately documented and explained in the application and are acceptable to the reviewing agency they may provide a basis for eliminating the control alternative.

In all cases, economic impacts need to be considered in conjunction with energy and environmental impacts (e.g., toxics and hazardous pollutant considerations) in selecting BACT. It is possible that the environmental impacts analysis or other considerations (as described elsewhere) would override the economic elimination criteria as described in this section. However, absent overriding environmental impacts concerns or other considerations, an acceptable demonstration of a adverse economic impact can be adequate basis for eliminating the control alternative.

IV.D.2.a. ESTIMATING THE COSTS OF CONTROL

Before costs can be estimated, the control system design parameters must be specified. The most important item here is to ensure that the design parameters used in costing are consistent with emissions estimates used in other portions of the PSD application (e.g., dispersion modeling inputs and permit emission limits). In general, the BACT analysis should present vendor-supplied design parameters. Potential sources of other data on design parameters are BID documents used to support NSPS development, control technique guidelines documents, cost manuals developed by EPA, or control data in trade publications. Table B-4 presents some example design parameters which are important in determining system costs.

To begin, the limits of the area or process segment to be costed specified. This well defined area or process segment is referred to as the control system battery limits. The second step is to list and cost each major piece of equipment within the battery limits. The top-down BACT analysis should provide this list of costed equipment. The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source [such as the OAQPS Control Cost Manual (Fourth Edition), EPA 450/3-90-006, January 1990, Table B-4]. Inadequate documentation of battery limits is one of the most common reasons for confusion in comparison of costs of the same controls applied to similar sources. For control options that are defined as inherently lower-polluting processes (and not add-on controls), the battery limits may be the entire process or project.

Design parameters should correspond to the specified emission level. The equipment vendors will usually supply the design parameters to the applicant, who in turn should provide them to the reviewing agency. In order to determine if the design is reasonable, the design parameters can be compared with those shown in documents such as the <u>OAQPS Control Cost Manual</u>, <u>Control Technology for Hazardous Air Pollutants (HAPS) Manual</u> (EPA 625/6-86-014, September 1986), and background information documents for NSPS and NESHAP regulations. If the design specified does not appear reasonable, then the applicant should be requested to supply performance test data for the control technology in question applied to the same source, or a similar source.

TABLE B-4. EXAMPLE CONTROL SYSTEM DESIGN PARAMETERS

Control	Example Design parameters
Wet Scrubbers	Scrubber liquor (water, chemicals, etc.) Gas pressure drop Liquid/gas ratio
Carbon Absorbers	Specific chemical species Gas pressure drop lbs carbon/lbs pollutant
Condensers	Condenser type Outlet temperature
Incineration	Residence time Temperature
Electrostatic Precipitator	Specific collection area (ft2/acfm) Voltage density
Fabric Filter	Air to cloth ratio Pressure drop
Selective Catalytic Reduction	Space velocity Ammonia to NOx molar ratio Pressure drop Catalyst life

Once the control technology alternatives and achievable emissions performance levels have been identified, capital and annual costs are developed. These costs form the basis of the cost and economic impacts (discussed later) used to determine and document if a control alternative should be eliminated on grounds of its economic impacts.

Consistency in the approach to decision-making is a primary objective of the top-down BACT approach. In order to maintain and improve the consistency of BACT decisions made on the basis of cost and economic considerations, procedures for estimating control equipment costs are based on EPA's OAQPS Control cost Manual and are set forth in Appendix B of this document. Applicants should closely follow the procedures in the appendix and any deviations should be clearly presented and justified in the documentation of the BACT analysis.

Normally the submittal of very detailed and comprehensive project cost data is not necessary. However, where initial control cost projections on the part of the applicant appear excessive or unreasonable (in light of recent cost data) more detailed and comprehensive cost data may be necessary to document the applicant's projections. An applicant proposing the top alternative usually does not need to provide cost data on the other possible control alternatives.

Total cost estimates of options developed for BACT analyses should be on order of plus or minus 30 percent accuracy. If more accurate cost data are available (such as specific bid estimates), these should be used. However, these types of costs may not be available at the time permit applications are being prepared. Costs should also be site specific. Some site specific factors are costs of raw materials (fuel, water, chemicals) and labor. For example, in some remote areas costs can be unusually high. For example, remote locations in Alaska may experience a 40-50 percent premium on installation costs. The applicant should document any unusual costing assumptions used in the analysis.

IV.D.2.b. COST EFFECTIVENESS

Cost effectiveness is the economic criterion used to assess the potential for achieving an objective at least cost. Effectiveness is measured in terms of tons of pollutant emissions removed. Cost is measured in terms of annualized control costs.

The Cost effectiveness calculations can be conducted on an average, or incremental basis. The resultant dollar figures are sensitive to the number of alternatives costed as well as the underlying engineering and cost parameters. There are limits to the use of cost-effectiveness analysis. For example, cost-effectiveness analysis should not be used to set the environmental objective. Second, cost-effectiveness should, in and of itself, not be construed as a measure of adverse economic impacts. There are two measures of cost-effectiveness that will be discussed in this section: (1) average cost-effectiveness, and (2) incremental cost-effectiveness.

<u>Average Cost Effectiveness</u>

Average cost effectiveness (total annualized costs of control divided by annual emission reductions, or the difference between the baseline emission rate and the controlled emission rate) is a way to present the costs of control. Average cost effectiveness is calculated as shown by the following formula:

$$\text{Average cost Effectiveness (dollars per ton removed)} = \frac{\text{Control option annualized cost}}{\text{Baseline emissions rate - Control option emissions rate}}$$

Costs are calculated in (annualized) dollars per year ($/yr) and emissions
rates are calculated in tons per year (tons/yr). The result is a cost effectiveness number in (annualized) dollars per ton ($/ton) of pollutant removed.

Calculating Baseline Emissions

The baseline emissions rate represents a realistic scenario of upper boundary uncontrolled emissions for the source. The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with State or local air pollution regulations, are not considered in calculating the baseline emissions. In other words, baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions. When calculating the cost effectiveness of adding post process emissions controls to certain inherently lower polluting processes, baseline emissions may be assumed to be the emissions from the lower polluting process itself. In other words, emission reduction credit can be taken for use of inherently lower polluting processes.

Estimating realistic upper-bound case scenario does not mean that the source operates in an absolute worst case manner all the time. For example, in
developing a realistic upper boundary case, baseline emissions calculations can also consider inherent physical or operational constraints on the source. Such constraints should accurately reflect the true upper boundary of the source's ability to physically operate and the applicant should submit documentation to verify these constraints. If the applicant does not adequately verify these constraints, then the reviewing agency should not be compelled to consider these constraints in calculating baseline emissions. In addition, the reviewing agency may require the applicant to calculate cost

effectiveness based on values exceeding the upper boundary assumptions to determine whether or not the assumptions have a deciding role in the BACT determination. If the assumptions have a deciding role in the BACT determination, the reviewing agency should include enforceable conditions in the permit to assure that the upper bound assumptions are not exceeded.

For example, VOC emissions from a storage tank might vary significantly with temperature, volatility of liquid stored, and throughput. In this case, potential emissions would be overestimated if annual VOC emissions were estimated by extrapolating over the course of a year VOC emissions based solely on the hottest summer day. Instead, the range of expected temperatures should be considered in determining annual baseline emissions. Likewise, potential emissions would be overestimated if one assumed that gasoline would be stored in a storage tank being built to feed an oil-fired power boiler or such a tank will be continually filled and emptied. On the other hand, an upper bound case for a storage tank being constructed to store and transfer liquid fuels at a marine terminal should consider emissions based on the most volatile liquids at a high annual throughput level since it would not be unrealistic for the tank to operate in such a manner.

In addition, historic upper bound operating data, typical for the source or industry, may be used in defining baseline emissions in evaluating the cost effectiveness of a control option for a specific source. For example, if for a source or industry, historical upper bound operations call for two shifts a day, it is not necessary to assume full time (8760 hours) operation on an annual basis in calculating baseline emissions. For comparing cost effectiveness, the same realistic upper boundary assumptions must, however, be used for both the source in question and other sources (or source categories) that will later be compared during the BACT analysis.

For example, suppose (based on verified historic data regarding the industry in question) a given source can be expected to utilize numerous colored inks over the course of a year. Each color ink has a different VOC content ranging from a high VOC content to a relatively low VOC content. The source verifies that its operation will indeed call for the application of numerous color inks. In this case, it is more realistic for the baseline emission calculation for the source (and other similar sources) to be based on the expected mix of inks that would be expected to result in an upper boundary case annual VOC emissions rather than an assumption that only one color (i.e, the ink with the highest VOC content) will be applied exclusively during the whole year.

In another example, suppose sources in a particular industry historically operate at most at 85 percent capacity. For BACT cost effectiveness purposes (but **not** for applicability), an applicant may calculate cost effectiveness using 85 percent capacity. However, in comparing costs with similar sources, the applicant must consistently use an 85 percent capacity factor for the cost effectiveness of controls on those other sources.

Although permit conditions are normally used to make operating assumptions enforceable, the use of "standard industry practice" parameters for cost effectiveness calculations (but **not** applicability determinations) can be acceptable without permit conditions. However, when a source projects operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) that are lower than standard industry practice or which have a deciding role in the BACT determination, then these parameters or assumptions must be made enforceable with permit conditions. If the applicant will not accept enforceable permit conditions, then the reviewing agency should use the absolute worst case uncontrolled emissions in calculating baseline emissions. This is necessary to ensure that the permit reflects the conditions under which the source intends to operate.

For example, the baseline emissions calculation for an emergency standby generator may consider the fact that the source does not intend to operate more than 2 weeks a year. On the other hand, baseline emissions associated with a base-loaded turbine would not consider limited hours of operation. This produces a significantly higher level of baseline emissions than in the case of the emergency/standby unit and results in more cost effective controls. As a consequence of the dissimilar baseline emissions, BACT for the two cases could be very different. Therefore, it is important that the applicant confirm that the operational assumptions used to define the source's baseline emissions (and BACT) are genuine. As previously mentioned, this is usually done through enforceable permit conditions which reflect limits on the source's operation which were used to calculate baseline emissions.

In certain cases, such explicit permit conditions may not be necessary. For example, a source for which continuous operation would be a physical impossibility (by virtue of its design) may consider this limitation in estimating baseline emissions, without a direct permit limit on operations. However, the permit agency has the responsibility to verify that the source is constructed and operated consistent with the information and design specifications contained in the permit application.

For some sources it may be more difficult to define what emissions level actually represents uncontrolled emissions in calculating baseline emissions. For example, uncontrolled emissions could theoretically be defined for a spray coating operation as the maximum VOC content coating at the highest possible rate of application that the spray equipment could physically process, (even though use of such a coating or application rate would be unrealistic for the source). Assuming use of a coating with a VOC content and application rate greater than expected is unrealistic and would result in an overestimate in the amount of emissions reductions to be achieved by the installation of various control options. Likewise, the cost effectiveness of the options could consequently be greatly underestimated. To avoid these problems, uncontrolled emission factors should be represented by the highest realistic VOC content of
the types of coatings and highest realistic application rates that would be used by the source, rather than by highest VOC based coating materials or rate of application in general.

Conversely, if uncontrolled emissions are underestimated, emissions reductions to be achieved by the various control options would also be underestimated and their cost effectiveness overestimated. For example, this type of situation occurs in the previous example if the baseline for the above coating operation was based on a VOC content coating or application rate that is too low [when the source had the ability and intent to utilize (even infrequently) a higher VOC content coating or application rate].

Incremental Cost Effectiveness

In addition to the average cost effectiveness of a control option, incremental cost effectiveness between control options should also be calculated. The incremental cost effectiveness should be examined in combination with the total cost effectiveness in order to justify elimination of a control option. The incremental cost effectiveness calculation compares the costs and emissions performance level of a control option to those of the next most stringent option, as shown in the following formula:

$$\text{Incremental Cost (dollars per incremental ton removed)} = \frac{\text{Total costs (annualized) of control option - Total costs (annualized) of next control option}}{\text{Next control option emission rate - Control option emissions rate}}$$

Care should be exercised in deriving incremental costs of candidate control options. Incremental cost-effectiveness comparisons should focus on annualized cost and emission reduction differences between **dominant** alternatives. Dominant set of control alternatives are determined by generating what is called the envelope of least-cost alternatives. This is a graphical plot of total annualized costs for a total emissions reductions for all control alternatives identified in the BACT analysis (see Figure B-1).

For example, assume that eight technically available control options for analysis are listed in the BACT hierarchy. These are represented as A through H in Figure B-1. In calculating incremental costs, the analysis should only be conducted for control options that are dominant among all possible options. In Figure B-1, the dominant set of control options, A, B, D, F, G, and H, represent the least-cost envelope depicted by the curvilinear line connecting them. Points C and E are inferior options and should not be considered in the

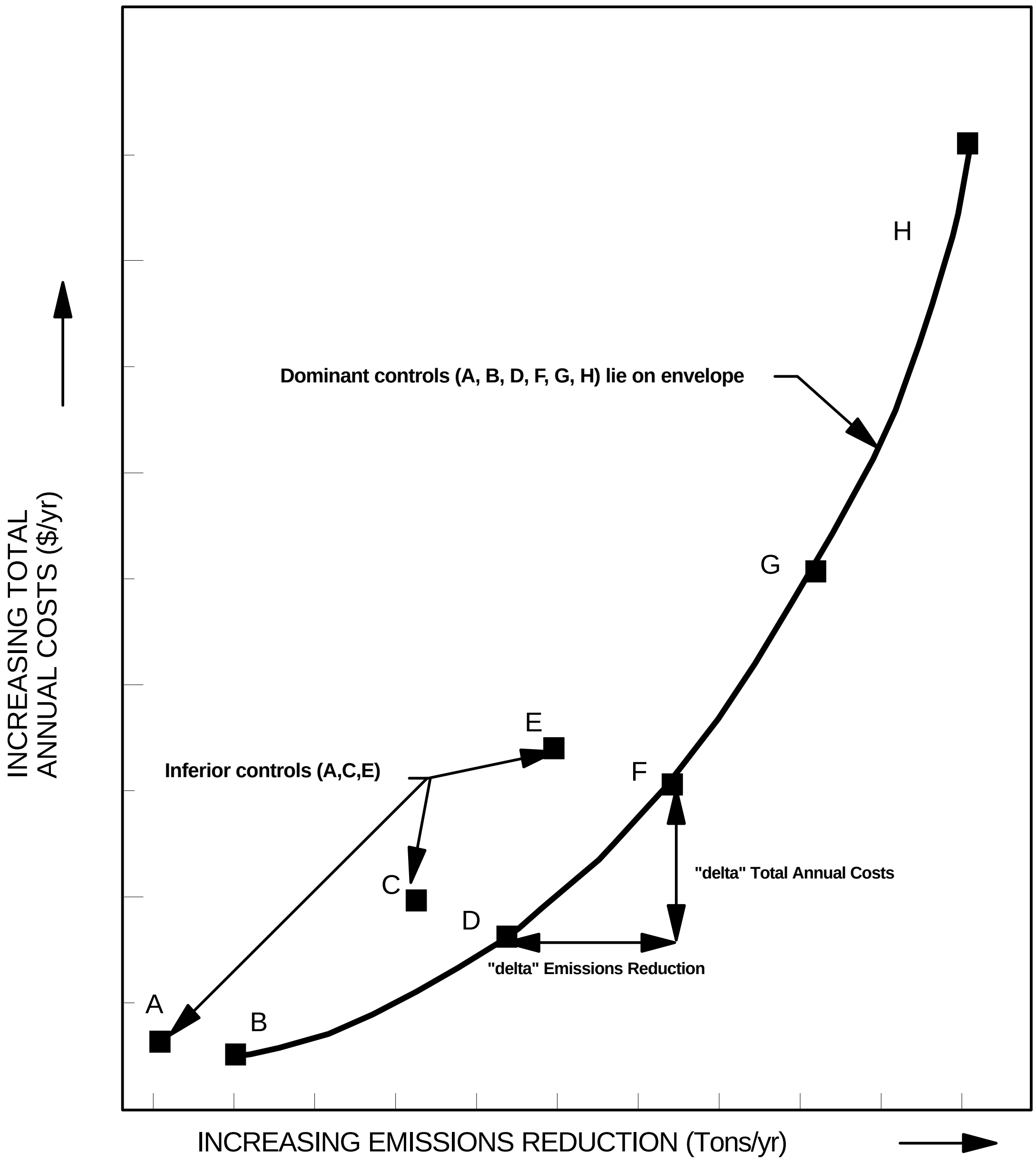

Figure B-1. LEAST-COST ENVELOPE

derivation of incremental cost effectiveness. Points A, C and E represent inferior controls because B will buy more emissions reduction for less money than A; and similarly, D and F will by more reductions for less money than E, respectively.

Consequently, care should be taken in selecting the dominant set of controls when calculating incremental costs. First, the control options need to be rank ordered in ascending order of annualized total costs. Then, as Figure B-1 illustrates, the most reasonable smooth curve of the control options is plotted. The incremental cost effectiveness is then determined by the difference in total annual costs between two contiguous options divided by the difference in emissions reduction. An example is illustrated in Figure B-1 for the incremental cost effectiveness for control option F. The vertical distance, "delta" Total Costs Annualized, divided by the horizontal distance, "delta" Emissions Reduced (tpy), would be the measure of the incremental cost effectiveness for option F.

A comparison of incremental costs can also be useful in evaluating the economic viability of a specific control option over a range of efficiencies. For example, depending on the capital and operational cost of a control device, total and incremental cost may vary significantly (either increasing or decreasing) over the operation range of a control device.

As a precaution, differences in incremental costs among dominant alternatives cannot be used by itself to argue one dominant alternative is preferred to another. For example, suppose dominant alternative is preferred to another. For example, suppose dominant alternatives B, D and F on the least-cost envelope (see Figure B-1) are identified as alternatives for a BACT analysis. We may observe the incremental cost effectiveness between dominant alternative B and D is $500 per ton whereas between dominant alternative D and F is $1000 per ton. Alternative D does <u>not</u> dominate alternative F. Both alternatives are dominant and hence on the least cost envelope. Alternative D cannot legitimately be preferred to F on grounds of incremental cost effectiveness.

In addition, when evaluating the total or incremental cost effectiveness of a control alternative, reasonable and supportable assumptions regarding control efficiencies should be made. An unrealistically low assessment of the emission reduction potential of a certain technology could result in inflated cost effectiveness figures.

The final decision regarding the reasonableness of calculated cost effectiveness values will be made by the review authority considering previous regulatory decisions. Study cost estimates used in BACT are typically accurate to ± 20 to 30 percent. Therefore, control cost options which are within ± 20 to 30 percent of each other should generally be considered to be indistinguishable when comparing options.

IV.D.2.c. DETERMINING AN ADVERSE ECONOMIC IMPACT

It is important to keep in mind that BACT is primarily a technology-based standard. In essence, if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT. However, unusual circumstances may greatly affect the cost of controls in a specific application. If so they should be documented. An example of an unusual circumstance might be the unavailability in an arid region of the large amounts of water needed for a scrubbing system. Acquiring water from a distant location might add unreasonable costs to the alternative, thereby justifying its elimination on economic grounds. Consequently, where unusual factors exist that result in cost/economic impacts beyond the range normally incurred by other sources in that category, the technology can be eliminated provided the applicant has adequately identified the circumstances, including the cost or other analyses, that show what is significantly different about the proposed source.

Where the cost of a control alternative for the specific source being reviewed is within the range of normal costs for that control alternative, the alternative may also be eligible for elimination in limited circumstances. This may occur, for example, where a control alternative has not been required as BACT (or its application as BACT has been extremely limited) and there is a clear demarcation between recent BACT control costs in that source category and the control costs for sources in that source category which have been driven by other constraining factors (e.g., need to meet a PSD increment or a NAAQS).

To justify elimination of an alternative on these grounds, the applicant should demonstrate to the satisfaction of the permitting agency that costs of pollutant removal (e.g., dollars per total ton removed) for the control alternative are disproportionately high when compared to the cost of control for the pollutant in recent BACT determinations. Specifically, the applicant should document that the cost to the applicant of the control alternative is significantly beyond the range of recent costs normally associated with BACT for the type of facility (or BACT control costs in general) for the pollutant. This type of analysis should demonstrate that a technically and economically feasible control option is nevertheless, by virtue of the magnitude of its associated costs and limited application, unreasonable or otherwise not "achievable" as BACT in the particular case. Total and incremental cost effectiveness numbers are factored into this type of analysis. However, such economic information should be coupled with a comprehensive demonstration, based on objective factors, that the technology is inappropriate in the specific circumstance.

The economic impact portion of the BACT analysis should not focus on inappropriate factors or exclude pertinent factors, as the results may be misleading. For example, the capital cost of a control option may appear excessive when presented by itself or as a percentage of the total project cost. However, this type of information can be misleading. If a large emissions reduction is projected, low or reasonable cost effectiveness numbers may validate the option as an appropriate BACT alternative irrespective of the apparent high capital costs. In another example, undue focus on incremental cost effectiveness can give an impression that the cost of a control alternative is unreasonably high, when, in fact, the total cost effectiveness, in terms of dollars per total ton removed, is well within the normal range of acceptable BACT costs.

IV.D.3. ENVIRONMENTAL IMPACTS ANALYSIS

The environmental impacts analysis is not to be confused with the air quality impact analysis (i.e., ambient concentrations), which is an independent statutory and regulatory requirement and is conducted separately from the BACT analysis. The purpose of the air quality analysis is to demonstrate that the source (using the level of control ultimately determined to be BACT) will not cause or contribute to a violation of any applicable national ambient air quality standard or PSD increment. Thus, regardless of the level of control proposed as BACT, a permit cannot be issued to a source that would cause or contribute to such a violation. In contrast, the environmental impacts portion of the BACT analysis concentrates on impacts other than impacts on air quality (i.e., ambient concentrations) due to emissions of the regulated pollutant in question, such as solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, or emissions of unregulated pollutants.

Thus, the fact that a given control alternative would result in only a slight decrease in ambient concentrations of the pollutant in question when compared to a less stringent control alternative should not be viewed as an adverse **environmental** impact justifying rejection of the more stringent control alternative. However, if the cost effectiveness of the more stringent alternative is exceptionally high, it may (as provided in section V.D.2.) be considered in determining the existence of an adverse **economic** impact that would justify rejection of the more stringent alternative.

The applicant should identify any significant or unusual environmental impacts associated with a control alternative that have the potential to affect the selection or elimination of a control alternative. Some control technologies may have potentially significant secondary (i.e., collateral) environmental impacts. Scrubber effluent, for example, may affect water quality and land use. Similarly, emissions of water vapor from technologies using cooling towers may affect local visibility. Other examples of secondary environmental impacts could include hazardous waste discharges, such as spent catalysts or contaminated carbon. Generally, these types of environmental concerns become important when sensitive site-specific receptors exist or when the incremental emissions reduction potential of the top control is only marginally greater than the next most effective option. However, the fact that a control device creates liquid and solid waste that must be disposed of does not necessarily argue against selection of that technology as BACT, particularly if the control device has been applied to similar facilities elsewhere and the solid or liquid waste problem under review is similar to those other applications. On the other hand, where the applicant can show that unusual circumstances at the proposed facility create greater problems than experienced elsewhere, this may provide a basis for the elimination of that control alternative as BACT.

The procedure for conducting an analysis of environmental impacts should be made based on a consideration of site-specific circumstances. In general, however, the analysis of environmental impacts starts with the identification and quantification of the solid, liquid, and gaseous discharges from the control device or devices under review. This analysis of environmental impacts should be performed for the entire hierarchy of technologies (even if the applicant proposes to adopt the "top", or most stringent, alternative). However, the analysis need only address those control alternatives with any significant or unusual environmental impacts that have the potential to affect the selection or elimination of a control alternative. Thus, the relative environmental impacts (both positive and negative) of the various alternatives can be compared with each other and the "top" alternative.

Initially, a qualitative or semi-quantitative screening is performed to narrow the analysis to discharges with potential for causing adverse environmental effects. Next, the mass and composition of any such discharges should be assessed and quantified to the extent possible, based on readily available information. Pertinent information about the public or environmental consequences of releasing these materials should also be assembled.

IV.D.3.a. EXAMPLES (Environmental Impacts)

The following paragraphs discuss some possible factors for considerations in evaluating the potential for an adverse other media impact.

! Water Impact

Relative quantities of water used and water pollutants produced and discharged as a result of use of each alternative emission control system relative to the "top" alternative would be identified. Where possible, the analysis would assess the effect on ground water and such local surface water quality parameters as ph, turbidity, dissolved oxygen, salinity, toxic chemical levels, temperature, and any other important considerations. The analysis should consider whether applicable water quality standards will be met and the availability and effectiveness of various techniques to reduce potential adverse effects.

! Solid Waste Disposal Impact

The quality and quantity of solid waste (e.g., sludges, solids) that must be stored and disposed of or recycled as a result of the application of each alternative emission control system would be compared with the quality and quantity of wastes created with the "top" emission control system. The composition and various other characteristics of the solid waste (such as permeability, water retention, rewatering of dried material, compression strength, leachability of dissolved ions, bulk density, ability to support vegetation growth and hazardous characteristics) which are significant with regard to potential surface water pollution or transport into and contamination of subsurface waters or aquifers would be appropriate for consideration.

! Irreversible or Irretrievable Commitment of Resources

The BACT decision may consider the extent to which the alternative emission control systems may involve a trade-off between short-term environmental gains at the expense of long-term environmental losses and the extent to which the alternative systems may result in irreversible or irretrievable commitment of resources (for example, use of scarce water resources).

! Other Environmental Impacts

Significant differences in noise levels, radiant heat, or dissipated static electrical energy may be considered.

One environmental impact that could be examined is the trade-off between emissions of the various pollutants resulting from the application of a specific control technology. The use of certain control technologies may lead to increases in emissions of pollutants other than those the technology was designed to control. For example, the use of certain volatile organic compound (VOC) control technologies can increase nitrogen oxides (NOx) emissions. In this instance, the reviewing authority may want to give consideration to any relevant local air quality concern relative to the secondary pollutant (in this case NOx) in the region of the proposed source. For example, if the region in the example were nonattainment for NOx, a premium could be placed on the potential NOx impact. This could lead to elimination of the most stringent VOC technology (assuming it generated high quantities of NOx) in favor of one having less of an impact on ambient NOx concentrations. Another example is the potential for higher emissions of toxic and hazardous pollutants from a municipal waste combustor operating at a low flame temperature to reduce the formation of NOx. In this case the real concern to mitigate the emissions of toxic and hazardous emissions (via high combustion temperatures) may well take precedent over mitigating NOx emissions through the use of a low flame temperature. However, in most cases (unless an overriding concern over the formation and impact of the secondary pollutant is clearly present as in the examples given), it is not expected that this type impact would affect the outcome of the decision.

Other examples of collateral environmental impacts would include hazardous waste discharges such as spent catalysts or contaminated carbon. Generally these types of environmental concerns become important when site-specific sensitive receptors exist or when the incremental emissions reduction potential of the top control option is only marginally greater than the next most effective option.

IV.D.3.b. CONSIDERATION OF EMISSIONS OF TOXIC AND HAZARDOUS AIR POLLUTANTS

The generation or reduction of toxic and hazardous emissions, including compounds not regulated under the Clean Air Act, are considered as part of the environmental impacts analysis. Pursuant to the EPA Administrator's decision in North County Resource Recovery Associates, PSD Appeal No. 85-2 (Remand Order, June 3, 1986), a PSD permitting authority should consider the effects of a given control alternative on emissions of toxics or hazardous pollutants not regulated under the Clean Air Act. The ability of a given control alternative to control releases of unregulated toxic or hazardous emissions must be evaluated and may, as appropriate, affect the BACT decision. Conversely, hazardous or toxic emissions resulting from a given control technology should also be considered and may, as appropriate, also affect the BACT decision.

Because of the variety of sources and pollutants that may be considered in this assessment, it is not feasible for the EPA to provide highly detailed national guidance on performing an evaluation of the toxic impacts as part of the BACT determination. Also, detailed information with respect to the type and magnitude of emissions of unregulated pollutants for many source categories is currently limited. For example, a combustion source emits hundreds of substances, but knowledge of the magnitude of some of these emissions or the hazards they produce is sparse. The EPA believes it is appropriate for agencies to proceed on a case-by-case basis using the best information available. Thus, the determination of whether the pollutants would be emitted in amounts sufficient to be of concern is one that the permitting authority has considerable discretion in making. However, reasonable efforts should be made to address these issues. For example, such efforts might include consultation with the:

! EPA Regional Office;

! Control Technology Center (CTC);

! National Air Toxics Information Clearinghouse;

! Air Risk Information Support Center in the Office of Air Quality Planning and Standards (OAQPS); and

! Review of the literature, such as; EPA-prepared compilations of emission factors.

Source-specific information supplied by the permit applicant is often the best source of information, and it is important that the applicant be made aware of its responsibility to provide for a reasonable accounting of air toxics emissions.

Similarly, once the pollutants of concern are identified, the permitting authority has flexibility in determining the methods by which it factors air toxics considerations into the BACT determination, subject to the obligation to make reasonable efforts to consider air toxics. Consultation by the review authority with EPA's implementation centers, particularly the CTC, is again advised.

It is important to note that several acceptable methods, including risk assessment, exist to incorporate air toxics concerns into the BACT decision. The depth of the toxics assessment will vary with the circumstances of the particular source under review, the nature and magnitude of the toxic pollutants, and the locality. Emissions of toxic or hazardous pollutant of concern to the permit agency should be identified and, to the extent possible, quantified. In addition, the effectiveness of the various control alternatives in the hierarchy at controlling the toxic pollutant should be estimated and summarized to assist in making judgements about how potential emissions of toxic or hazardous pollutants may be mitigated through the selection of one control option over another. For example, the response to the Administrator made by EPA Region IX in its analysis of the North County permitting decision illustrates one of several approaches (for further information see the September 22, 1987 EPA memorandum from Mr. Gerald Emission titled "Implementation of North County Resource Recover PSD Remand" and July 28, 1988 EPA memorandum from Mr. John Calcagni titled "Supplemental guidance on Implementing the North County Prevention of Significant Deterioration (PSD) Remand").

Under a top-down BACT analysis, the control alternative selected as BACT will most likely reduce toxic emissions as well as the regulated pollutant. An example is the emissions of heavy metals typically associated with coal combustion. The metals generally are a portion of, or adsorbed on, the fine particulate in the exhaust gas stream. Collection of the particulate in a high efficiency fabric filter rather than a low efficiency electrostatic precipitator reduces criteria pollutant particulate matter emissions and toxic heavy metals emissions. Because in most instances the interests of reducing toxics coincide with the interests of reducing the pollutants subject to BACT, consideration of toxics in the BACT analysis generally amounts to quantifying toxic emission levels for the various control options.

In limited other instances, though, control of regulated pollutant emissions may compete with control of toxic compounds, as in the case of certain selective catalytic reduction (SCR) NOx control technologies. The SCR technology itself results in emissions of ammonia, which increase, generally speaking, with increasing levels of NOx control. It is the intent of the toxics screening in the BACT procedure to identify and quantify this type of toxic effect. Generally, toxic effects of this type will not necessarily be overriding concerns and will likely not to affect BACT decisions. Rather, the intent is to require a screening of toxics emissions effects to ensure that a possible overriding toxics issue does not escape notice.

On occasion, consideration of toxics emissions may support the selection of a control technology that yields less than the maximum degree of reduction in emissions of the regulated pollutant in question. An example is the municipal solid waste combustor and resource recovery facility that was the subject of the North County remand. Briefly, BACT for SO2 and PM was selected to be a lime slurry spray drier followed by a fabric filter. The combination yields good SO2 control (approximately 83 percent), good PM control (approximately 99.5 percent) and also removes acid gases (approximately 95 percent), metals, dioxins, and other unregulated pollutants. In this instance, the permitting authority determined that good balanced control of regulated and unregulated pollutants took priority over achieving the maximum degree of emissions reduction for one or more regulated pollutants. Specifically, higher levels (up to 95 percent) of SO2 control could have been obtained by a wet scrubber.

IV.E. SELECTING BACT (STEP 5)

The most effective control alternative not eliminated in Step 4 is selected as BACT.

It is important to note that, regardless of the control level proposed by the applicant as BACT, the ultimate BACT decision is made by the permit issuing agency after public review. The applicant's role is primarily to provide information on the various control options and, when it proposes a less stringent control option, provide a detailed rationale and supporting documentation for eliminating the more stringent options. It is the responsibility of the permit agency to review the documentation and rationale presented and; (1) ensure that the applicant has addressed all of the most effective control options that could be applied and; (2) determine that the applicant has adequately demonstrated that energy, environmental, or economic impacts justify any proposal to eliminate the more effective control options. Where the permit agency does not accept the basis for the proposed elimination of a control option, the agency may inform the applicant of the need for more information regarding the control option. However, the BACT selection essentially should default to the highest level of control for which the applicant could not adequately justify its elimination based on energy, environmental and economic impacts. If the applicant is unable to provide to the permit agency's satisfaction an adequate demonstration for one or more control alternatives, the permit agency should proceed to establish BACT and prepare a draft permit based on the most effective control option for which an adequate justification for rejection was not provided.

IV.F. OTHER CONSIDERATIONS

Once energy, environmental, and economic impacts have been considered, BACT can only be made more stringent by other considerations outside the normal scope of the BACT analysis as discussed under the above steps. Examples include cases where BACT does not produce a degree of control stringent enough to prevent exceedances of a national ambient air quality standard or PSD increment, or where the State or local agency will not accept the level of control selected as BACT and requires more stringent controls to preserve a greater amount of the available increment. A permit cannot be issued to a source that would cause or contribute to such a violation, regardless of the outcome of the BACT analysis. Also, States which have set ambient air quality standards at levels tighter than the federal standards may demand a more stringent level of control at a source to demonstrate compliance with the State standards. Another consideration which could override the selected BACT are legal constraints outside of the Clean Air Act requiring the application of a more stringent technology (e.g., a consent decree requiring a greater degree of control). In all cases, regardless of the rationale for the permit requiring a more stringent emissions limit than would have otherwise been chosen as a result of the BACT selection process, the emission limit in the final permit (and corresponding control alternative) represents BACT for the permitted source on a case-by-case basis.

The BACT emission limit in a new source permit is not set until the final permit is issued. The final permit is not issued until a draft permit has gone through public comment and the permitting agency has had an opportunity to consider any new information that may have come to light during the comment period. Consequently, in setting a proposed or final BACT limit, the permit agency can consider new information it learns, including recent permit decisions, subsequent to the submittal of a complete application. This emphasizes the importance of ensuring that prior to the selection of a proposed BACT, all potential sources of information have been reviewed by the source to ensure that the list of potentially applicable control alternatives is complete (most importantly as it relates to any more effective control options than the one chosen) and that all considerations relating to economic, energy and environmental impacts have been addressed.

V. ENFORCEABILITY OF BACT

To complete the BACT process, the reviewing agency must establish an enforceable emission limit for each subject emission unit at the source and for each pollutant subject to review that is emitted from the source. If technological or economic limitations in the application of a measurement methodology to a particular emission unit would make an emissions limit infeasible, a design, equipment, work practice, operation standard, or combination thereof, may be prescribed. Also, the technology upon which the BACT emissions limit is based should be specified in the permit. These requirements should be written in the permit so that they are specific to the individual emission unit(s) subject to PSD review.

The emissions limits must be included in the proposed permit submitted for public comment, as well as the final permit. BACT emission limits or conditions must be met on a continual basis at all levels of operation (e.g., limits written in pounds/MMbtu or percent reduction achieved), demonstrate protection of short term ambient standards (limits written in pounds/hour) and be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements). Consequently, the permit must:

! be able to show compliance or noncompliance (i.e., through monitoring times of operation, fuel input, or other indices of operating conditions and practices); and

! specify a reasonable averaging time consistent with established reference methods, contain reference methods for determining compliance, and provide for adequate reporting and recordkeeping so that the permitting agency can determine the compliance status of the source.

VI. EXAMPLE BACT ANALYSES FOR GAS TURBINES

Note: The following example provided is for illustration only. The example source is fictitious and has been created to highlight many of the aspects of the top-down process. Finally, it must be noted that the cost data and other numbers presented in the example are used only to demonstrate the BACT decision making process. Cost data are used in a relative sense to compare control costs among sources in a source category or for a pollutant. Determination of appropriate costs is made on a case-by-case basis.

In this section a BACT analysis for a stationary gas turbine project is presented and discussed under three alternative operating scenarios:

- Example 1--Simple Cycle Gas Turbines Firing Natural Gas
- Example 2--Combined Cycle Gas Turbines Firing Natural Gas
- Example 3--Combined Cycle Gas Turbines Firing Distillate Oil

The purpose of the examples are to illustrate points to be considered in developing BACT decision criteria for the source under review and selecting BACT. They are intended to illustrate the process rather than provide universal guidance on what constitutes BACT for any particular source category. BACT must be determined on a case-by-case basis.

These examples are not based on any actual analyses performed for the purposes of obtaining a PSD permit. Consequently, the actual emission rates, costs, and design parameters used are neither representative of any actual case nor do they apply to any particular facility.

VI.A. EXAMPLE 1--SIMPLE CYCLE GAS TURBINES FIRING NATURAL GAS

VI.A.1 PROJECT SUMMARY

Table B-5 presents project data, stationary gas design parameters, and uncontrolled emission estimates for the new source in example 1. The gas turbine is designed to provide peaking service to an electric utility. The planned operating hours are less than 1000 hours per year. Natural gas fuel will be fired. The source will be limited through enforceable conditions to the specified hours of operation and fuel type. The area where the source is to be located is in compliance for all criteria pollutants. No other changes are proposed at this facility, and therefore the net emissions change will be equal to the emissions shown on Table B-5. Only NOx emissions are significant (i.e., greater than the 40 tpy significance level for NOx) and a BACT analysis is required for NOx emissions only.

VI.A.2. BACT ANALYSIS SUMMARY

VII.A.2.a. CONTROL TECHNOLOGY OPTIONS

The first step in evaluating BACT is identifying all candidate control technology options for the emissions unit under review. Table B-6 presents the list of control technologies selected as potential BACT candidates. The first three control technologies, water or steam injection and selective catalytic reduction, were identified by a review of existing gas turbine facilities in operation. Selective noncatalytic reduction was identified as a potential type of control technology because it is an add-on NOx control which has been applied to other types of combustion sources.

TABLE B-5. EXAMPLE 1--COMBUSTION TURBINE DESIGN PARAMETERS

Characteristics	
Number of emissions units	1
Unit Type	Gas Turbines
Cycle Type	Simple-cycle
Output	75 MW
Exhaust temperature,	1,000 °F
Fuel(s)	Natural Gas
Heat rate, Btu/kw hr	11,000
Fuel flow, Btu/hr	1,650 million
Fuel flow, lb/hr	83,300
Service Type	Peaking
Operating Hours (per year)	1,000
Uncontrolled Emissions, tpy(a)	
NO_x	564 (169 ppm)
SO_2	<1
CO	4.6 (6 ppm)
VOC	1
PM	5 (0.0097 gr/dscf)

(a) Based on 1000 hours per year of operation at full load

TABLE B-6. EXAMPLE 1--SUMMARY OF POTENTIAL NOx CONTROL TECHNOLOGY OPTIONS

		In Service On:			
Control technology(a)	Typical control efficiency range (% reduction)	Simple cycle turbines	Combined cycle gas turbines	Other combustion sources(c)	Technically feasible on simple cycle turbines
Selective Catalytic Reductions	40-90	No	Yes	Yes	Yes(b)
Water Injection	30-70	Yes	Yes	Yes	Yes
Steam Injection	30-70	No	Yes	Yes	No
Low NOx Burner	30-70	Yes	Yes	Yes	Yes
Selective Noncatalytic Reduction	20-50	No	Yes	Yes	No

(a) Ranked in order of highest to lowest stringency.
(b) Exhaust must be diluted with air to reduce its temperature to 600-750°F.
(c) Boiler incinerators, etc.

In this example, the control technologies were identified by the applicant based on a review of the BACT/LAER Clearinghouse, and discussions with State agencies with experience permitting gas turbines in NOx nonattainment areas. A preliminary meeting with the State permit issuing agency was held to determine whether the permitting agency felt that any other applicable control technologies should be evaluated and they agreed on the proposed control hierarchy.

VI.A.2.b. TECHNICAL FEASIBILITY CONSIDERATIONS

Once potential control technologies have been identified, each technology is evaluated for its technical feasibility based on the characteristics of the source. Because the gas turbines in this example are intended to be used for peaking service, a heat recovery steam generator (HRSG) will not be included. A HRSG recovers heat from the gas turbine exhaust to make steam and increase overall energy efficiency. A portion of the steam produced can be used for steam injection for NOx control, sometimes increasing the effectiveness of the net injection control system. However, the electrical demands of the grid dictate that the turbine will be brought on line only for short periods of time to meet peak demands. Due to the lag time required to bring a heat recovery steam generator on line, it is not technically feasible to use a HRSG at the facility. Use of an HRSG in this instance was shown to interfere with the performance of the unit for peaking service, which requires immediate response times for the turbine. Although it was shown that a HRSG was not feasible and therefore not available, water and steam are readily available for NOx control since the turbine will be located near an existing steam generating powerplant.

The turbine type and, therefore, the turbine model selection process, affects the achievability of NOx emissions limits. Factors which the customer considered in selecting the proposed turbine model were outlined in the application as: the peak demand which must be met, efficiency of the gas turbine, reliability requirements, and the experience of the utility with the operation and maintenance service of the particular manufacturer and turbine design. In this example, the proposed turbine is equipped with a combustor designed to achieve an emission level, at 15 percent O2, of 25 ppm NOx with steam injection or 42 ppm with water injection.[2]

Selective noncatalytic reduction (SNCR) was eliminated as technically infeasible and therefore not available, because this technology requires a flue gas temperature of 1300 to 2100°F. The exhaust from the gas turbines will be approximately 1000°F, which is below the required temperature range.

Selective catalytic reduction (SCR) was evaluated and no basis was found to eliminate this technology as technically infeasible. However, there are no known examples where SCR technology has been applied to a simple-cycle gas turbine or to a gas turbine in peaking service. In all cases where SCR has been applied, there was an HRSG which served to reduce the exhaust temperature to the optimum range of 600-750oF and the gas turbine was operated continuously. Consequently, application of SCR to a simple cycle turbine involves special circumstances. For this example, it is assumed that dilution air can be added to the gas turbine exhaust to reduce its temperature. However, the dilution air will make the system more costly due to higher gas flows, and may reduce the removal efficiency because the NOx concentration at the inlet will be reduced. Cost considerations are considered later in the analysis.

VI.A.2.c. CONTROL TECHNOLOGY HIERARCHY

After determining technical feasibility, the applicant selected the control levels for evaluation shown in Table B-7. Although the applicant

[2] For some gas turbine models, 25 ppm is not achievable with either water or steam injection.

TABLE B-7. EXAMPLE 1--CONTROL TECHNOLOGY HIERARCHY

	Emissions Limits	
Control Technology	ppm(a)	TPY
Steam Injection plus SCR	13	44
Steam Injection at maximum(b) design rate	25	84
Water Injection at maximum(b) design rate	42	140
Steam Injection to meet NSPS	93	312

(a) Corrected to 15 percent oxygen.

(b) Water to fuel ratio.

reported that some sites in California have achieved levels as low as 9 ppm, at this facility a 13 ppm level was determined to be the feasible limit with SCR. This decision is based on the lowest achievable level with steam injection of 25 ppm and an SCR removal efficiency of 50 percent. Even though the reported removal efficiencies for SCR are up to 90 percent at some facilities, at this facility the actual NOx concentration at the inlet to the SCR system will only be approximately 17 ppm (at actual conditions) due to the dilution air required. Also the inlet concentrations, flowrates, and temperatures will vary due to the high frequency of startups. These factors make achieving the optimum 90 percent NOx removal efficiency unrealistic. Based on discussions with SCR vendors, the applicant has established a 50 percent removal efficiency as the highest level achievable, thereby resulting in a 13 ppm level (i.e., 50 percent of 25 ppm).

The next most stringent level achievable would be steam injection at the maximum water-to-fuel ratio achievable by the unit within its design operating range. For this particular gas turbine model, that level is 25 ppm as supported by vendor NOx emissions guarantees and unit test data. The applicant provided documentation obtained from the gas turbine manufacturer[3] verifying ability to achieve this range.

After steam injection the next most stringent level of control would be water injection at the maximum water-to-fuel ratio achievable by the unit within its design operating range. For this particular gas turbine model, that level is 42 ppm as supported by vendor NOx emissions guarantees and actual unit test data. The applicant provided documentation obtained from the gas turbine manufacturer verifying ability to achieve this range.

The least stringent level evaluated by the applicant was the current NSPS for utility gas turbines. For this model, that level is 93 ppm at 15 percent O2. By definition, BACT can be no less stringent than NSPS.

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[3] It should be noted that achievability of the NO_x limits is dependent on the turbine model, fuel, type of wet injection (water or steam), and system design. Not all gas turbine models or fuels can necessarily achieve these levels.

Therefore, less stringent levels are not evaluated.

VI.A.2.d. IMPACTS ANALYSIS SUMMARY

The next steps completed by the applicant were the development of the cost, economic, environmental and energy impacts of the different control alternatives. Although the top-down process would allow for the selection of the top alternative without a cost analysis, the applicant felt cost/economic impacts were excessive and that appropriate documentation may justify the elimination of SCR as BACT and therefore chose to quantify cost and economic impacts. Because the technologies in this case are applied in combination, it was necessary to quantify impacts for each of the alternatives. The impact estimates are shown in Table B-8. Adequate documentation of the basis for the impacts was determined to be included in the PSD permit application.

The incremental cost impacts shown are the cost of the alternative compared to the next most stringent control alternative. Figure B-2 is a plot of the least-cost envelope defined by the list of control options.

VI.A.2.e. TOXICS ASSESSMENT

If SCR were applied, potential toxic emissions of ammonia could occur. Ammonia emissions resulting from application of SCR could be as large as 20 tons per year. Application of SCR would reduce NOx by an additional 20 tpy over steam injection alone (25 ppm)(not including ammonia emissions).

Another environmental impact considered was the spent catalyst which would have to be disposed of at certain operating intervals. The catalyst contains vanadium pentoxide, which is listed as a hazardous waste under RCRA regulations (40 CFR 261.3). Disposal of this waste creates an additional economic and environmental burden. This was considered in the applicant's proposed BACT determination.

TABLE B-8. EXAMPLE 1--SUMMARY OF TOP-DOWN BACT IMPACT ANALYSIS RESULTS FOR NO_x

	Emissions per Turbine			Economic Impacts				Energy Impacts	Environmental Impacts	
Control alternative	Emissions (lb/hr)	(tpy)	Emissions reduction(a) (tpy)	Installed capital cost(b) ($)	Total annualized cost(c) ($/yr)	Cost effectiveness over baseline(d) ($/ton)	Incremental cost effectiveness(e) ($/ton)	Incremental increase over baseline(f) (MMBtu/yr)	Toxics impact (Yes/No)	Adverse environmental impact (Yes/No)
13 ppm Alternative	44	22	260	11,470,000	1,717,000(g)	6,600	56,200	464,000	Yes	No
25 ppm Alternative	84	42	240	1,790,000	593,000	2,470	8,460	30,000	No	No
42 ppm Alternative	140	70	212	1,304,000	356,000	1,680	800	15,300	No	No
NSPS Alternative	312	156	126	927,000	288,000	2,285		8,000	No	No
Uncontrolled Baseline	564	282	-	-	-	-	-	-	-	-

(a) Emissions reduction over baseline control level.
(b) Installed capital cost relative to baseline.
(c) Total annualized cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation) is used to express capital costs in present-day annual costs.
(d) Cost Effectiveness over baseline is equal to total annualized cost for the control option divided by the emissions reductions resulting from the uncontrolled baseline.
(e) The optional incremental cost effectiveness criteria is the same as the total cost effectiveness criteria except that the control alternative is considered relative to the next most stringent alternative rather than the baseline control alternative.
(f) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline control alternative expressed in equivalent millions of Btus per year.
(g) Assued 10 year catalyst life since this turbine operates only 1000 hours per year. Assumptions made on catalyst life may have a profound affect upon cost effectiveness.

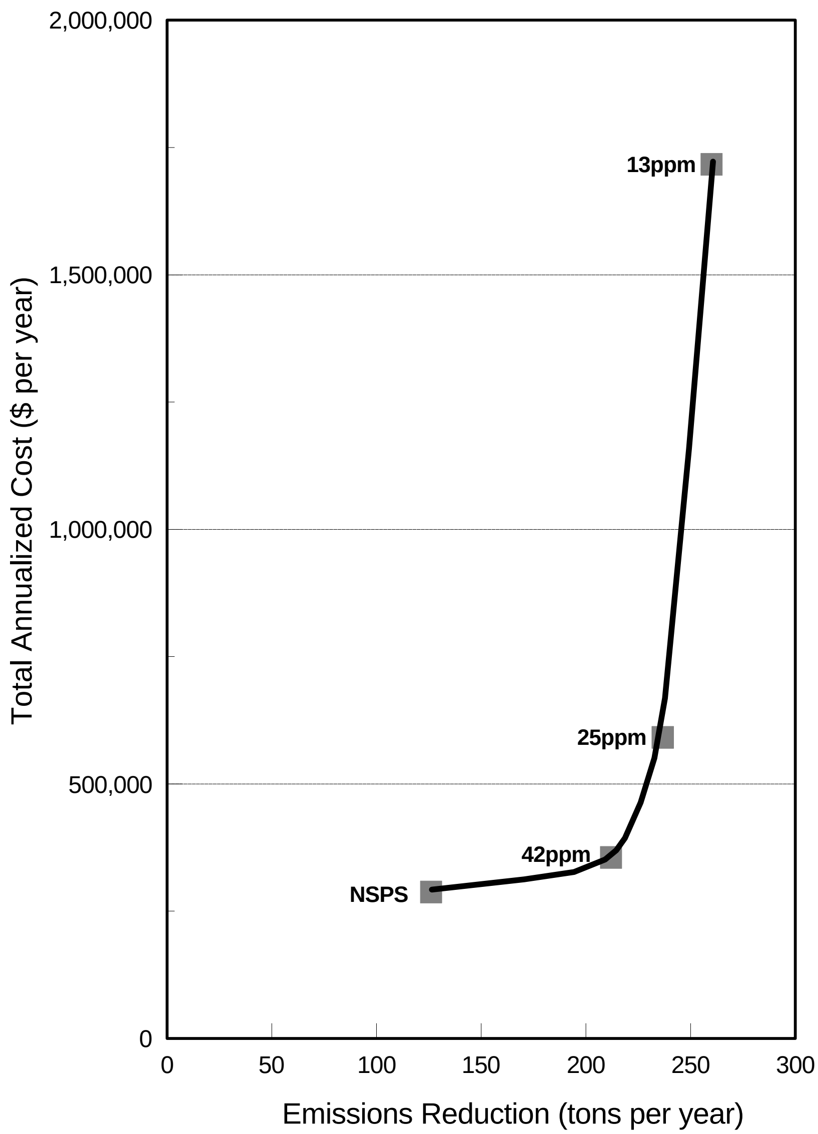

Figure B-2. Least-Cost Envelope for Example 1

VI.A.2.f. RATIONALE FOR PROPOSED BACT

Based on these impacts, the applicant proposed eliminating the 13 ppm alternative as economically infeasible. The applicant documented that the cost effectiveness is high at 6,600 $/ton, and well out of the range of recent BACT NOx control costs for similar sources. The incremental cost effectiveness of $56,200 also is high compared to the incremental cost effectiveness of the next option.

The applicant documented that the other combustion turbine sources which have applied SCR have much higher operating hours (i.e., all were permitted as base-loaded units). Also, these sources had heat recovery steam generators so that the cost effectiveness of the application of SCR was lower. For this source, dilution air must be added to cool the flue gas to the proper temperature. This increases the cost of the SCR system relative to the same gas turbine with a HRSG. Therefore, the other sources had much lower cost impacts for SCR relative to steam injection alone, and much lower cost effectiveness numbers. Application of SCR would also result in emission of ammonia, a toxic chemical, of possibly 20 tons per year while reducing NOx emissions by 20 tons per year. The applicant asserted that, based on these circumstances, to apply SCR in this case would be an unreasonable burden compared to what has been done at other similar sources.

Consequently, the applicant proposed eliminating the SCR plus steam injection alternative. The applicant then accepted the next control alternative, steam injection to 25 ppmv. The use of steam injection was shown by the applicant to be consistent with recent BACT determinations for similar sources. The review authority concurred with the proposed elimination of SCR and the selection of a 25 ppmv limit as BACT. The use of steam injection was shown by the applicant to be consistent with recent BACT determinations for similar sources. The review authority concurred with the proposed elimination of SCR and the selection of a 25 ppmv limit as BACT.

VI.B. EXAMPLE 2--COMBINED CYCLE GAS TURBINES FIRING NATURAL GAS

Table B-9 presents the design parameters for an alternative set of circumstances. In this example, two gas turbines are being installed. Also, the operating hours are 5000 per year and the new turbines are being added to meet intermediate loads demands. The source will be limited through enforceable conditions to the specified hours of operation and fuel type. In this case, HRSG units are installed. The applicable control technologies and control technology hierarchy are the same as the previous example except that no dilution is required for the gas turbine exhaust because the HRSG serves to reduce the exhaust temperature to the optimum level for SCR operation. Also, since there is no dilution required and fewer startups, the most stringent control option proposed is 9 ppm based on performance limits for several other natural gas fired baseload combustion turbine facilities.

Table B-10 presents the results of the cost and economic impact analysis for the example and Figure B-3 is a plot of the least-cost envelope defined by the list of control options. The incremental cost impacts shown are the cost of the alternative compared to the next most stringent control alternative. Due to the increased operating hours and design changes, the economic impacts of SCR are much lower for this case. There does not appear to be a persuasive argument for stating that SCR is economically infeasible. Cost effectiveness numbers are within the range typically required of this and other similar source types.

In this case, there would also be emissions of ammonia. However, now the magnitude of ammonia emissions, approximately 40 tons per year, is much lower than the additional NOx reduction achieved, which is 270 tons per year.

Under these alternative circumstances, PM emissions are also now above the significance level (i.e., greater than 25 tpy). The gas turbine

TABLE B-9. EXAMPLE 2--COMBUSTION TURBINE DESIGN PARAMETERS

Characteristics	
Number of emission units	2
Emission units	Gas Turbine
Cycle Type	Combined-cycle
Output	
Gas Turbines (2 @ 75 MW each)	150 MW
Steam Turbine (no emissions generated)	70 MW
Fuel(s)	Natural Gas
Gas Turbine Heat Rate, Btu/kw-hr	11,000 Btu/kw-hr
Fuel Flow per gas turbine, Btu/hr	1,650 million
Fuel Flow per gas turbine, lb/hr	83,300
Service Type	Intermediate
Hours per year of operation	5000
Uncontrolled Emissions per gas turbine, tpy (a)(b)	
NO_x	1,410 (169 ppm)
SO_2	<1
CO	23 (6 ppm)
VOC	5
PM	25 (0.0097 gr/dscf)

(a) Based on 5000 hours per year of operation.

(b) Total uncontrolled emissions for the proposed project is equal to the pollutants uncontrolled emission rate multiplied by 2 turbines. For example, total NO_x = (2 turbines) x 1410 tpy per turbine) = 2820 tpy.

TABLE B-10. EXAMPLE 2--SUMMARY OF TOP-DOWN BACT IMPACT ANALYSIS RESULTS FOR NO_x

	Emissions per Turbine			Economic Impacts				Energy Impacts	Environmental Impacts	
Control alternative	Emissions (lb/hr)	(tpy)	Emissions reduction(a,h) (tpy)	Installed capital cost(b) ($)	Total annualized cost(c) ($/yr)	Cost effectiveness over baseline(d) ($/ton)	Incremental cost effectiveness(e) ($/ton)	Incremental increase over baseline(f) (MMBtu/yr)	Toxics impact (Yes/No)	Adverse environmental impact (Yes/No)
9 ppm Alternative	30	75	1,335	10,980,000	3,380,000(g)	2,531	12,200	160,000	Yes	No
25 ppm Alternative	84	210	1,200	1,791,000	1,730,000	1,440	6,050	105,000	No	No
42 ppm Alternative	140	350	1,060	1,304,000	883,000	833	181	57,200	No	No
NSPS Alternative	312	780	630	927,000	805,000	1,280		27,000	No	No
Uncontrolled Baseline	564	1,410	-	-	-	-	-	-	-	-

(a) Emissions reduction over baseline control level.
(b) Installed capital cost relative to baseline.
(c) Total annualized cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation) is used to express capital costs in present-day annual costs.
(d) Cost Effectiveness over baseline is equal to total annualized cost for the control option divided by the emissions reductions resulting from the uncontrolled baseline.
(e) The optional incremental cost effectiveness criteria is the same as the total cost effectiveness criteria except that the control alternative is considered relative to the next most stringent alternative rather than the baseline control alternative.
(f) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline control alternative expressed in equivalent millions of Btus per year.
(g) Assumes a 2 year catalyst life. Assumptions made on catalyst life may have a profound affect upon cost effectiveness.
(h) Since the project calls for two turbines, actual project wide emissions reductions for an alternative will be equal to two times the reduction listed.

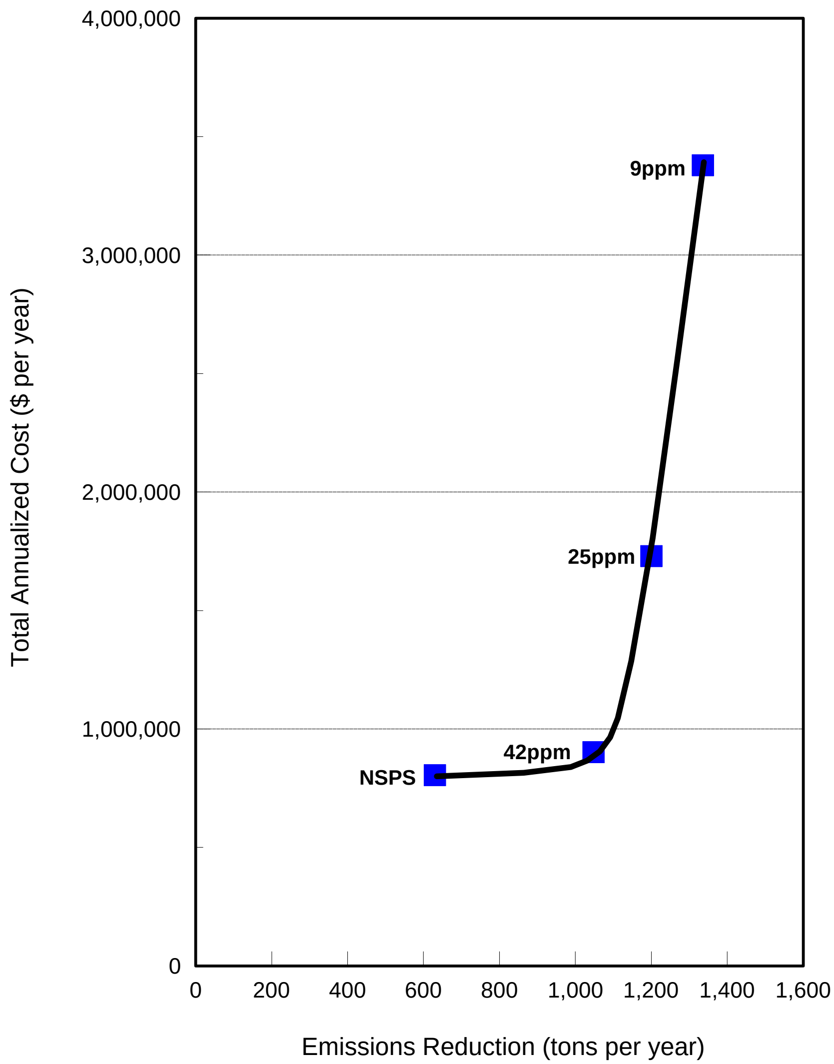

Figure B-3. Least-Cost Envelope for Example 2 combustors are designed to combust the fuel as completely as possible and therefore reduce PM to the lowest possible level. Natural gas contains no solids and solids are removed from the injected water. The PM emission rate without add-on controls is on the same order (0.009 gr/dscf) as that for other particulate matter sources controlled with stringent add-on controls (e.g., fabric filter). Since the applicant documented that precombustion or add-on controls for PM have never been required for natural gas fired turbines, the reviewing agency accepted the applicants analysis that natural gas firing was BACT for PM emissions and that no additional analysis of PM controls was required.

VI.C. EXAMPLE 3--COMBINED CYCLE GAS TURBINE FIRING DISTILLATE OIL

In this example, the same combined cycle gas turbines are proposed except that distillate oil is fired rather than natural gas. The reason is that natural gas is not available on site and there is no pipeline within a reasonable distance. The fuel change raises two issues; the technical feasibility of SCR in gas turbines firing sulfur bearing fuel, and NOx levels achievable with water injection while firing fuel oil.

In this case the applicant proposed to eliminate SCR as technically infeasible because sulfur present in the fuel, even at low levels, will poison the catalyst and quickly render it ineffective. The applicant also noted that there are no cases in the U.S. where SCR has been applied to a gas turbine firing distillate oil as the primary fuel.[4]

A second issue would be the most stringent NOx control level achievable with wet injection. For oil firing the applicant has proposed 42 ppm at 15 percent oxygen. Due to flame characteristics inherent with oil firing, and limits on the amount of water or steam that can be injected, 42 ppm is the lowest NOx emission level achievable with distillate oil firing. Since

[4] Though this argument was considered persuasive in this case, advances in catalyst technology have now made SCR with oil firing technically feasible.

natural gas is not available and SCR is technically infeasible, 42 ppm is the most stringent alternative considered. Based on the cost effectiveness of wet injection, approximately 833 $/ton, there is no economic basis to eliminate the 42 ppm option since this cost is well within the range of BACT costs for NOx control. Therefore, this option is proposed as BACT.

The switch to oil from gas would also result in SO2, CO, PM, and beryllium emissions above significance levels. Therefore, BACT analyses would also be required for these pollutants. These analyses are not shown in this example, but would be performed in the same manner as the BACT analysis for NOx.

VI.D. OTHER CONSIDERATIONS

The previous judgements concerning economic feasibility were in an area meeting NAAQS for both NOx and ozone. If the natural gas fired simple cycle gas turbine example previously presented were sited adjacent to a Class I area, or where air quality improvement poses a major challenge, such as next to a nonattainment area, the results may differ. In this case, even though the region of the actual site location is achieving the NAAQS, adherence to a local or regional NOx or ozone attainment strategy might result in the determination that higher costs than usual are appropriate. In such situations, higher costs (e.g., 6,600 $/ton) may not necessarily be persuasive in eliminating SCR as BACT.

While it is not the intention of BACT to prevent construction, it is possible that local or regional air quality management concerns regarding the need to minimize the air quality impacts of new sources would lead the permitting authority to require a source to either achieve stringent emission control levels or, at a minimum, that control cost expenditures meet certain cost levels without consideration of the resultant economic impact to the source.

Besides local or regional air quality concerns, other site constraints may significantly impact costs of particular control technologies. For the examples previously presented, two factors of concern are land and water availability.

The cost of the raw water is usually a small part of the cost of wet controls. However, gas turbines are sometimes located in remote locations. Though water can obviously be trucked to any location, the costs may be very high.

Land availability constraints may occur where a new source is being located at an existing plant. In these cases, unusual design and additional structural requirements could make the costs of control technologies which are commonly affordable prohibitively expensive. Such considerations may be pertinent to the calculations of impacts and ultimately the selection of BACT.

CHAPTER C

THE AIR QUALITY ANALYSIS

I. INTRODUCTION

An applicant for a PSD permit is required to conduct an air quality analysis of the ambient impacts associated with the construction and operation of the proposed new source or modification. The main purpose of the air quality analysis is to demonstrate that new emissions emitted from a proposed major stationary source or major modification, in conjunction with other applicable emissions increases and decreases from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable **NAAQS** or **PSD increment**. Ambient impacts of noncriteria pollutants must also be evaluated.

A separate air quality analysis must be submitted for each regulated pollutant if the applicant proposes to emit the pollutant in a significant amount from a new major stationary source, or proposes to cause a significant net emissions increase from a major modification (see *Table I-A-4*, chapter A of this part). [***Note: The air quality analysis requirement also applies to any pollutant whose rate of emissions from a proposed new or modified source is considered to be "significant" because the proposed source would construct within 10 kilometers of a Class I area and would have an ambient impact on such area equal to or greater than 1 µg/m³, 24-hour average.]*** Regulated pollutants include (1) pollutants for which a NAAQS exists (criteria pollutants) and (2) other pollutants, which are regulated by EPA, for which no NAAQS exist (noncriteria pollutants).

Each air quality analysis will be unique, due to the variety of sources and meteorological and topographical conditions that may be involved. Nevertheless, the air quality analysis must be accomplished in a manner consistent with the requirements set forth in either EPA's PSD regulations under 40 CFR 52.21, or a State or local PSD program approved by EPA pursuant to 40 CFR 51.166. Generally, the analysis will involve (1) an assessment of existing air quality, which may include ambient monitoring data and air quality dispersion modeling results, and (2) predictions, using dispersion modeling, of ambient concentrations that will result from the applicant's proposed project and future growth associated with the project.

In describing the various concepts and procedures involved with the air quality analysis in this section, it is assumed that the reader has a basic understanding of the principles involved in collecting and analyzing ambient monitoring data and in performing air dispersion modeling. Considerable guidance is contained in EPA's Ambient Monitoring Guidelines for Prevention of Significant Deterioration [Reference 1] and Guideline on Air Quality Models (Revised) [Reference 2] . Numerous times throughout this chapter, the reader will be referred to these guidance documents, hereafter referred to as the *PSD Monitoring Guideline* and the *Modeling Guideline*, respectively.

In addition, because of the complex character of the air quality analysis and the site-specific nature of the modeling techniques involved, applicants are advised to review the details of their proposed modeling analysis with the appropriate reviewing agency before a complete PSD application is submitted. This is best done using a modeling protocol. The modeling protocol should be submitted to the reviewing agency for review and approval prior to commencing any extensive analysis. Further description of the modeling protocol is contained in this chapter.

The PSD applicant should also be aware that, while this chapter focuses primarily on compliance with the NAAQS and PSD increments, additional impact analyses are required under separate provisions of the PSD regulations for determining any impairment to visibility, soils and vegetation that might result, as well as any adverse impacts to Class I areas. These provisions are described in the following chapters D and E, respectively.

II. NATIONAL AMBIENT AIR QUALITY STANDARDS AND PSD INCREMENTS

As described in the introduction to this chapter, the air quality analysis is designed to protect the ***national ambient air quality standards*** (NAAQS) and ***PSD increments***. The NAAQS are maximum concentration "ceilings" measured in terms of the total concentration of a pollutant in the atmosphere (See *Table C-1*). For a new or modified source, compliance with any NAAQS is based upon the total estimated air quality, which is the sum of the ambient estimates resulting from existing sources of air pollution (modeled source impacts plus measured background concentrations, as described in this section) and the modeled ambient impact caused by the applicant's proposed emissions increase (or net emissions increase for a modification) and associated growth.

A PSD increment, on the other hand, is the maximum allowable <u>increase</u> in concentration that is allowed to occur above a baseline concentration for a pollutant (see section II.E). The baseline concentration is defined for each pollutant (and relevant averaging time) and, in general, is the ambient concentration existing at the time that the first complete PSD permit application affecting the area is submitted. Significant deterioration is said to occur when the amount of new pollution would exceed the applicable PSD increment. It is important to note, however, that the air quality cannot deteriorate beyond the concentration allowed by the applicable NAAQS, even if not all of the PSD increment is consumed.

II.A CLASS I, II, AND III AREAS AND INCREMENTS.

The PSD requirements provide for a system of area classifications which affords States an opportunity to identify local land use goals. There are three area classifications. Each classification differs in terms of the amount of growth it will permit before significant air quality deterioration would be deemed to occur. Class I areas have the smallest increments and thus allow only a small degree of air quality deterioration. Class II areas can

TABLE C-1. National Ambient Air Quality Standards

Pollutant/averaging time	Primary Standard	Secondary Standard
Particulate Matter		
o PM_{10}, annual[a]	50 μg/m^3	50 μg/m^3
o PM_{10}, 24-hour[b]	150 μg/m^3	150 μg/m^3
Sulfur Dioxide		
o SO_2, annual[c]	80 μg/m^3 (0.03 ppm)	
o SO_2, 24-hour[d]	365 μg/m^3 (0.14 ppm)	
o SO_2, 3-hour[d]		1,300 μg/m^3 (0.5 ppm)
Nitrogen Dioxide		
o NO_2, annual[c]	0.053 ppm (100 μg/m^3	0.053 ppm (100 μg/m^3)
Ozone		
o O_3, 1-hour[b]	0.12 ppm (235 μg/m^3)	0.12 ppm (235 μg/m^3)
Carbon Monoxide		
o CO, 8-hour[d]	9 ppm (10 mg/m^3)	--
o CO, 1-hour[d]	35 ppm (40 mg/m^3)	--
Lead		
o Pb, calendar quarter[c]	1.5 μg/m^3	--

a Standard is attained when the expected annual arithmetic mean is less than or equal to 50 μg/m^3.
b Standard is attained when the expected number of exceedances is less than or equal to 1.
c Never to be exceeded.
d Not to be exceeded more than once per year.

accommodate normal well-managed industrial growth. Class III areas have the largest increments and thereby provide for a larger amount of development than either Class I or Class II areas.

Congress established certain areas, e.g., wilderness areas and national parks, as mandatory Class I areas. These areas cannot be redesignated to any other area classification. All other areas of the country were initially designated as Class II. Procedures exist under the PSD regulations to redesignate the Class II areas to either Class I or Class III, depending upon a State's land management objectives.

PSD increments for SO_2 and particulate matter--measured as total suspended particulate (TSP)--have existed in their present form since 1978. On July 1, 1987, EPA revised the NAAQS for particulate matter and established the new PM-10 indicator by which the NAAQS are to be measured. (Since each State is required to adopt these revised NAAQS and related implementation requirements as part of the approved implementation plan, PSD applicants should check with the appropriate permitting agency to determine whether such State action has already been taken. Where the PM-10 NAAQS are not yet being implemented, compliance with the TSP-based ambient standards is still required in accordance with the currently-approved State implementation plan.) Simultaneously with the promulgation of the PM-10 NAAQS, EPA announced that it would develop PM-10 increments to replace the TSP increments. Such new increments have not yet been promulgated, however. Thus the national PSD increment system for particulate matter is still based on the TSP indicator.

The EPA promulgated PSD increments for NO_2 on October 17, 1988. These new increments become effective under EPA's PSD regulations (40 CFR 52.21) on November 19, 1990, although States may have revised their own PSD programs to incorporate the new increments for NO_2 on some earlier date. Until November 19, 1990, PSD applicants should determine whether the NO_2 increments are being implemented in the area of concern; if so, they must include the necessary analysis, if applicable, as part of a complete permit application. [NOTE: the "trigger date" (described below in section II.B) for the NO_2 increments has been established by regulation as of February 8, 1988. This applies to all State PSD programs as well as EPA's Part 52 PSD program. Thus, consumption of the NO_2 increments may actually occur before the increments become effective in any particular PSD program.] The PSD increments for SO_2, TSP and NO_2 are summarized in *Table C-2*.

II.B ESTABLISHING THE BASELINE DATE

As already described, the ***baseline concentration*** **is** the reference point for determining air quality deterioration in an area. The baseline concentration is essentially the air quality existing at the time of the first complete PSD permit application submittal affecting that area. In general, then, the submittal date of the first complete PSD application in an area is the "baseline date." On or before the date of the first PSD application, most emissions are considered to be part of the baseline concentration, and emissions changes which occur after that date affect the amount of available PSD increment. However, to fully understand how and when increment is consumed or expanded, three different dates related to baseline must be explained. In chronological order, these dates are as follows:

- *the* ***major source baseline date***;
- *the* ***trigger date***; and
- *the* ***minor source baseline date***.

The ***major source baseline date*** is the date after which actual emissions associated with construction (i.e., physical changes or changes in the method of operation) at a major stationary source affect the available PSD increment. Other changes in actual emissions occurring at any source after the major source baseline date do not affect the increment, but instead (until after the minor source baseline date is established) contribute to the baseline concentration. The ***trigger date*** is the date after which the minor source

TABLE C-2. PSD INCREMENTS

($\mu g/m^3$)

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	Class I	Class II	Class III
<u>Sulfur Dioxide</u>			
o SO_2, annual[a]	2	20	40
o SO_2, 24-hour[b]	5	91	182
o SO_2, 3-hour[b]	25	512	700
<u>Particulate Matter</u>			
o TSP, annual[a]	5	19	37
o TSP, 24-hour[b]	10	37	75
<u>Nitrogen Dioxide</u>			
o NO_2, annual[a]	2.5	25	50

a Never to be exceeded.

b Not to be exceeded more than once per year.

baseline date (described below) may be established. Both the major source baseline date and the trigger date are fixed dates, although different dates apply to (1) SO_2 and particulate matter, and (2) NO_2, as follows:

4444444444444444444444444444444444444444444444444444444444444444444444444

Pollutant	Major Source Baseline Date	Trigger Date
PM	January 6, 1975	August 7, 1977
SO_2	January 6, 1975	August 7, 1977
NO_2	February 8, 1988	February 8, 1988

The **minor source baseline date** is the earliest date after the trigger date on which a complete PSD application is received by the permit reviewing agency. If the application that established the minor source baseline date is ultimately denied or is voluntarily withdrawn by the applicant, the minor source baseline date remains in effect nevertheless. Because the date marks the point in time after which actual emissions changes from all sources affect the available increment (regardless of whether the emissions changes are a result of construction), it is often referred to as the "baseline date."

The minor source baseline date for a particular pollutant is triggered by a PSD applicant only if the proposed increase in emissions of that pollutant is significant. For instance, a PSD application for a major new source or modification that proposes to increase its emissions in a significant amount for SO_2, but in an insignificant amount for PM, will establish the minor source baseline date for SO_2 but not for PM. Thus, the minor source baseline dates for different pollutants (for which increments exist) need not be the same in a particular area.

II.C ESTABLISHING THE BASELINE AREA

The area in which the minor source baseline date is established by a PSD permit application is known as the ***baseline area***. The extent of a baseline area is limited to intrastate areas and may include one or more areas designated as attainment or unclassified under Section 107 of the Act. The baseline area established pursuant to a specific PSD application is to include 1) all portions of the attainment or unclassifiable area in which the PSD applicant would propose to locate, amd 2) any attainment or unclassifiable area in which the proposed emissions would have a significant ambient impact. For this purpose, a significant impact is defined as at least a 1 $\mu g/m^3$ annual increase in the average annual concentration of the applicable pollutant. Again, a PSD applicant's establishment of a baseline area in one State does not trigger the minor source baseline date in, or extend the baseline area into, another State.

II.D REDEFINING BASELINE AREAS (AREA REDESIGNATIONS)

It is possible that the boundaries of a baseline area may not reasonably reflect the area affected by the PSD source which established the baseline area. A state may redefine the boundaries of an existing baseline area by redesignating the section 107 areas contained therein. Section 107(d) of the Clean Air Act specifically authorizes states to submit redesignations to the EPA. Consequently, a State may submit redefinitions of the boundaries of attainment or unclassifiable areas at any time, as long as the following criteria are met:

- *area redesignations can be no smaller than the 1 $\mu g/m^3$ area of impact of the triggering source*; and

- *the boundaries of any redesignated area cannot intersect the 1 $\mu g/m^3$ area of impact of any major stationary source that established or would have established a minor source baseline date for the area proposed for redesignation.*

II.E INCREMENT CONSUMPTION AND EXPANSION

The amount of PSD increment that has been consumed in a PSD area is determined from the emissions increases and decreases which have occurred from sources since the applicable baseline date. It is useful to note, however, that in order to determine the amount of PSD increment consumed (or the amount of available increment), no determination of the baseline concentration needs to be made. Instead, increment consumption calculations must reflect only the ambient pollutant concentration <u>change</u> attributable to increment-affecting emissions.

Emissions increases that consume a portion of the applicable increment are, in general, all those <u>not</u> accounted for in the baseline concentration and specifically include:

! *actual emissions increases occurring after the* ***major source baseline date****, which are associated with physical changes or changes in the method of operation (i.e., construction) at a major stationary source*; and

!*actual emissions increases at any stationary source, area source, or mobile source occurring after the* ***minor source baseline date****.*

The amount of available increment may be added to, or "expanded," in two ways. The primary way is through the reduction of actual emissions from any source after the minor source baseline date. Any such emissions reduction would increase the amount of available increment to the extent that ambient concentrations would be reduced.

Increment expansion may also result from the reduction of actual emissions after the major source baseline date, but <u>before</u> the minor source baseline date, if the reduction results from a physical change or change in the method of operation (i.e., construction) at a major stationary source. Moreover, the reduction will add to the available increment only if the reduction is included in a federally enforceable permit or SIP provision. Thus, for major stationary sources, actual emissions <u>reductions</u> made prior to the minor source baseline date expand the available increment just as <u>increases</u> before the minor source baseline date consume increment.

The creditable increase of an existing stack height or the application of any other creditable dispersion technique may affect increment consumption or expansion in the same manner as an actual emissions increase or decrease. That is, the effects that a change in the effective stack height would have on ground level pollutant concentrations generally should be factored into the increment analysis. For example, this would apply to a raised stack height occurring in conjunction with a modification at a major stationary source prior to the minor source baseline date, or to any changed stack height occurring after the minor source baseline date. It should be noted, however, that any increase in a stack height, in order to be creditable, must be consistent with the EPA's stack height regulations; credit cannot be given for that portion of the new height which exceeds the height demonstrated to be the good engineering practice (GEP) stack height.

Increment consumption (and expansion) will generally be based on changes in actual emissions reflected by the normal source operation for a period of 2 years. However, if little or no operating data are available, as in the case of permitted emission units not yet in operation at the time of the increment analysis, the **potential to emit** must be used instead. Emissions data requirements for modeling increment consumption are described in *Section IV.D.4*. Further guidance for identifying increment-consuming sources (and emissions) is provided in *Section IV.C.2*.

II.F BASELINE DATE AND BASELINE AREA CONCEPTS -- EXAMPLES

An example of how a baseline area is established is illustrated in *Figure C-1*. A major new source with the potential to emit significant amounts of SO_2 proposes to locate in County C. The applicant submits a complete PSD application to the appropriate reviewing agency on October 6, 1978. (The trigger date for SO_2 is August 7, 1977.) A review of the State's SO_2 attainment designations reveals that attainment status is listed by individual counties in the state. Since County C is designated attainment for SO_2, and the source proposes to locate there, October 6, 1978 is established as the minor source baseline date for SO_2 for the entire county.

Dispersion modeling of proposed SO_2 emissions in accordance with approved methods reveals that the proposed source's ambient impact will exceed 1 ug/m^3 (annual average) in Counties A and B. Thus, the same minor source baseline date is also established throughout Counties A and B. Once it is triggered, the minor source baseline date for Counties A, B and C establishes the time after which all emissions changes affect the available increments in those three counties.

Although SO_2 impacts due to the proposed emissions are above the significance level of 1 $\mu g/m^3$ (annual average) in the adjoining State, the proposed source does not establish the minor source baseline date in that State. This is because, as mentioned in Section II.C of this chapter, baseline areas are <u>intrastate</u> areas only.

The fact that a PSD source's emissions cannot trigger the minor source baseline date across a State's boundary should not be interpreted as precluding the applicant's emissions from consuming increment in another State. Such increment-consuming emissions (e.g., SO_2 emissions increases resulting from a physical change or a change in the method of operation at a

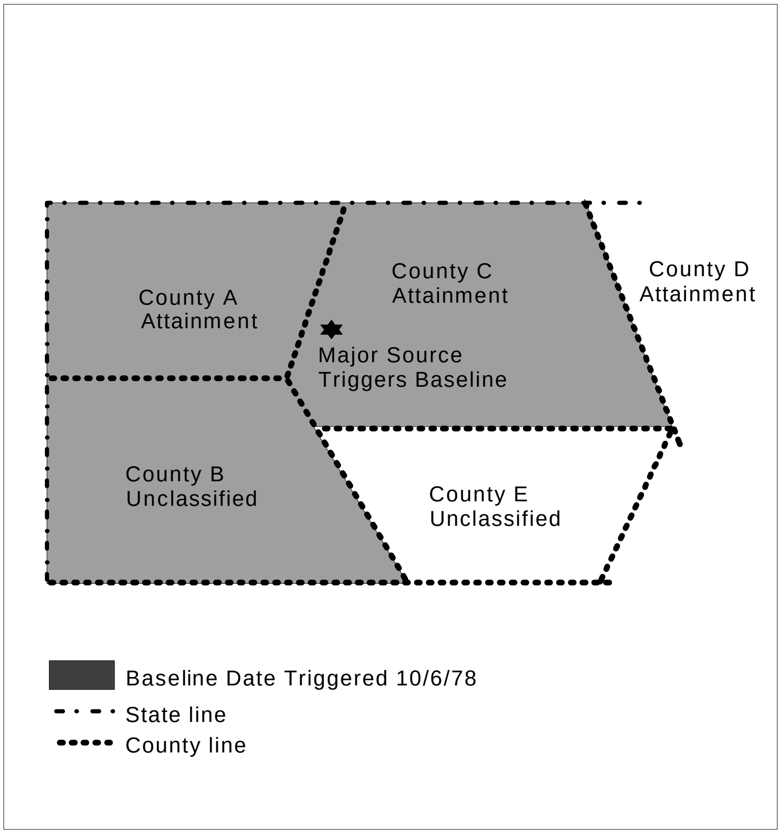

Figure C-1. Establishing the Baseline Area.

major stationary source after January 6, 1975) that affect another State will consume increment there even though the minor source baseline date has not been triggered, but are not considered for increment-consuming purposes until after the minor source baseline date has been independently established in that State. A second example, illustrated in *Figure C-2*, demonstrates how a baseline area may be redefined. Assume that the State in the first example decides that it does not want the minor source baseline date to be established in the western half of County A where the proposed source will not have a significant annual impact (i.e., 1 $\mu g/m^3$, annual average). The State, therefore, proposes to redesignate the boundaries of the existing section 107 attainment area, comprising all of County A, to create two separate attainment areas in that county. If EPA agrees that the available data support the change, the redesignations will be approved. At that time, the October 6, 1978 minor source baseline date will no longer apply to the newly-established attainment area comprising the western portion of County A.

If the minor source baseline date has not been triggered by another PSD application having a significant impact in the redesignated western portion of County A, the SO_2 emissions changes occurring after October 6, 1978 from minor point, area, and mobile sources, and from nonconstruction-related activities at all major stationary sources in this area will be transferred into the baseline concentration. In accordance with the major source baseline date, construction-related emissions changes at major point sources continue to consume or expand increment in the westerm poriton of County A which is no longer part of the original baseline area.

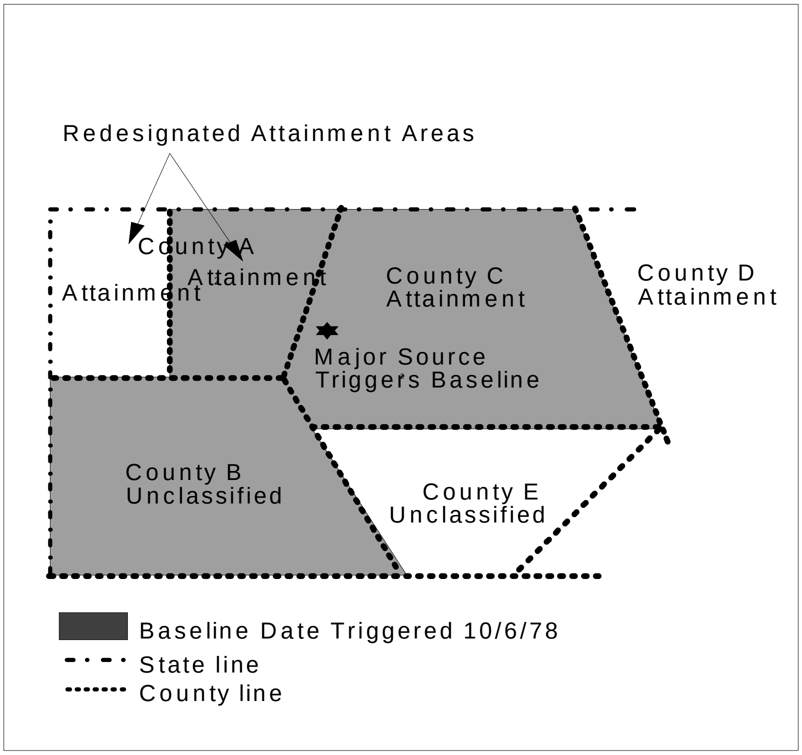

Figure C-2. Redefining the Baseline Area.

III. AMBIENT DATA REQUIREMENTS

An applicant should be aware of the potential need to establish and operate a site-specific monitoring network for the collection of certain ambient data. With respect to ***air quality data***, the PSD regulations contain provisions requiring an applicant to provide an ambient air quality analysis which may include pre-application monitoring data, and in some instances post-construction monitoring data, for any pollutant proposed to be emitted by the new source or modification. In the absence of available monitoring data which is representative of the area of concern, this requirement could involve the operation of a site-specific air quality monitoring network by the applicant. Also, the need for ***meteorological data***, for any dispersion modeling that must be performed, could entail the applicant's operation of a site-specific meteorological network.

Pre-application data generally must be gathered over a period of at least 1 year and the data are to represent at least the 12-month period immediately preceding receipt of the PSD application. Consequently, it is important that the applicant ascertain the need to collect any such data and proceed with the required monitoring activities as soon as possible in order to avoid undue delay in submitting a complete PSD application.

III.A PRE-APPLICATION AIR QUALITY MONITORING

For any criteria pollutant that the applicant proposes to emit in significant amounts, continuous ambient monitoring data may be required as part of the air quality analysis. If, however, either (1) the predicted ambient impact, i.e., the highest modeled concentration for the applicable averaging time, caused by the proposed significant emissions increase (or significant net emissions increase), or (2) the existing ambient pollutant concentrations are less than the prescribed significant monitoring value (see *Table C-3*), the permitting agency has discretionary authority to exempt an applicant from this data requirement.

TABLE C-3. SIGNIFICANT MONITORING CONCENTRATIONS

Pollutant	Air Quality Concentration (μg/m^3) and Averaging Time	
Carbon monoxide	575	(8-hour)
Nitrogen dioxide	14	(Annual)
Sulfur dioxide	13	(24-hour)
Particulate Matter, TSP	10	(24-hour)
Particulate Matter, PM-10	10	(24-hour)
Ozone	*a*	
Lead	0.1	(3-month)
Asbestos	*b*	
Beryllium	0.001	(24-hour)
Mercury	0.25	(24-hour)
Vinyl chloride	15	(24-hour)
Fluorides	0.25	(24-hour)
Sulfuric acid mist	*b*	
Total reduced sulfur (including H_2S)	*b*	
Reduced sulfur (including H_2S)	*b*	
Hydrogen sulfide	0.2	(1-hour)

a No significant air quality concentration for ozone monitoring has been established. Instead, applicants with a net emissions increase of 100 tons/year or more of VOC's subject to PSD would be required to perform an ambient impact analysis, including pre-application monitoring data.

b Acceptable monitoring techniques may not be available at this time. Monitoring requirements for this pollutant should be discussed with the permitting agency.

The determination of the proposed project's effects on air quality (for comparison with the significant monitoring value) is based on the results of the dispersion modeling used for establishing the impact area (see Section IV.B of this chapter). Modeling by itself or in conjunction with available monitoring data should be used to determine whether the existing ambient concentrations are equal to or greater than the significant monitoring value. The applicant may utilize a screening technique for this purpose, or may elect to use a refined model. Consultation with the permitting agency is advised before any model is selected. Ambient impacts from existing sources are estimated using the same model input data as are used for the NAAQS analysis, as described in section IV.D.4 of this chapter.

If a potential threat to the NAAQS is identified by the modeling predictions, then continuous ambient monitoring data should be required, even when the predicted impact of the proposed project is less than the significant monitoring value. This is especially important when the modeled impacts of existing sources are uncertain due to factors such as complex terrain and uncertain emissions estimates.

Also, if the location of the proposed source or modification is not affected by other major stationary point sources, the assessment of existing ambient concentrations may be done by evaluating available monitoring data. It is generally preferable to use data collected within the area of concern; however, the possibility of using measured concentrations from representative "regional" sites may be discussed with the permitting agency. The *PSD Monitoring Guideline* provides additional guidance on the use of such regional sites.

Once a determination is made by the permitting agency that ambient monitoring data must be submitted as part of the PSD application, the requirement can be satisfied in one of two ways. First, under certain conditions, the applicant may use existing ambient data. To be acceptable, such data must be judged by the permitting agency to be representative of the air quality for the area in which the proposed project would construct and operate. Although a State or local agency may have monitored air quality for several years, the data collected by such efforts may not necessarily be adequate for the preconstruction analysis required under PSD. In determining the representativeness of any existing data, the applicant and the permitting agency must consider the following critical items (described further in the *PSD Monitoring Guideline)*:

- *monitor location*;
- *quality of the data*; and
- *currentness of the data*.

If existing data are not available, or they are judged not to be representative, then the applicant must proceed to establish a site-specific monitoring network. The EPA strongly recommends that the applicant prepare a monitoring plan before any actual monitoring begins. Some permitting agencies may require that such a plan be submitted to them for review and approval. In any case, the applicant will want to avoid any possibility that the resulting data are unacceptable because of such things as improperly located monitors, or an inadequate number of monitors. To assure the accuracy and precision of the data collected, proper quality assurance procedures pursuant to *Appendix B of 40 CFR Part 58* must also be followed. The recommended minimum contents of a monitoring plan, and a discussion of the various considerations to be made in designing a PSD monitoring network, are contained in the *PSD Monitoring Guideline*.

The PSD regulations generally require that the applicant collect 1 year of ambient data (EPA recommends 80 percent data recovery for PSD purposes). However, the permitting agency has discretion to accept data collected over a shorter period of time (but in no case less than 4 months) if a complete and adequate analysis can be accomplished with the resulting data. Any decision to approve a monitoring period shorter than 1 year should be based on a demonstration by the applicant (through historical data or dispersion modeling) that the required air quality data will be obtained during a time period, or periods, when maximum ambient concentrations can be expected.

For a pollutant for which there is no NAAQS (i.e., a noncriteria pollutant), EPA's general position is not require monitoring data, but to base the air quality analysis on modeled impacts. However, the permitting agency may elect to require the submittal of air quality monitoring data for noncriteria pollutants in certain cases, such as where:

- ! *a State has a standard for a non-criteria pollutant*;
- ! *the reliability of emissions data used as input to modeling existing sources is highly questionable*; and
- ! *available models or complex terrain make it difficult to estimate air quality or the impact of the proposed or modification.*

The applicant will need to confer with the permitting agency to determine whether any ambient monitoring may be required. Before the agency exercises its discretion to require such monitoring, there should be an acceptable measurement method approved by EPA or the appropriate permitting agency.

With regard to particulate matter, where two different indicators of the pollutant are being regulated, EPA considers the PM-10 indicator to represent the criteria form of the pollutant (the NAAQS are now expressed in terms of ambient PM-10 concentrations) and TSP is viewed as the non-criteria form. Consequently, EPA intends to apply the pre-application monitoring requirements to PM-10 primarily, while treating TSP on a discretionary basis in light of its noncriteria status. Although the PSD increments for particulate matter are still based on the TSP indicator, modeling data, not ambient monitoring data, are used for increment analyses.

Ambient air quality data collected by the applicant must be presented in the PSD application as part of the air quality analysis. Monitoring data collected for a criteria pollutant may be used in conjunction with dispersion modeling results to demonstrate NAAQS compliance. Each PSD application involves its own unique set of factors, i.e., the integration of measured ambient data and modeled projections. Consequently, the amount of data to be used and the manner of presentation are matters that should be discussed with the permitting agency.

III.B POST-CONSTRUCTION AIR QUALITY MONITORING

The *PSD Monitoring Guideline* recommends that post-construction monitoring be done when there is a valid reason, such as (1) when the NAAQS are threatened, and (2) when there are uncertainties in the data bases for modeling. Any decision to require post-construction monitoring will generally be made after the PSD application has been thoroughly reviewed. It should be noted that the PSD regulations do not require that the significant monitoring concentrations be considered by the permitting agency in determining the need for post-construction monitoring.

Existing monitors can be considered for collecting post-construction ambient data as long as they have been approved for PSD monitoring purposes. However, the location of the monitors should be checked to ascertain their appropriateness if other new sources or modifications have subsequently occurred, because the new emissions from the more recent projects could alter the location of points of maximum ambient concentrations where ambient measurements need to be made.

Generally, post-construction monitoring should not begin until the source is operating near intended capacity. If possible the collection of data should be delayed until the source is operating at a rate equal to or greater than 50 percent of design capacity. The *PSD Monitoring Guideline* provides, however, that in no case should post-construction monitoring be delayed later than 2 years after the start-up of the new source or modification.

Post-approval ozone monitoring is an alternative to pre-application monitoring for applicants proposing to emit VOC's if they choose to accept nonattainment preconstruction review requirements, including LAER, emissions and air quality offsets, and statewide compliance of other sources under the same ownership. As indicated in Table C-3, pre-application monitoring for ozone is required when the proposed source or modification would emit at least 100 tons per year of volatile organic compounds (VOC). Note that this emissions rate for VOC emissions is a surrogate for the significant monitoring concentration for the pollutant ozone (see *Table C-3*). Under 40 CFR 52.21(m)(1)(vi), post-approval monitoring data for ozone is required (and cannot be waived) in conjunction with the aforementioned nonattainment review requirements when the permitting agency waives the requirement for pre-application ozone monitoring data. The post-approval period may begin any time after the source receives its PSD permit. In no case should the post-approval monitoring be started later than 2 years after the start-up of the new source or modification.

III.C METEOROLOGICAL MONITORING

Meteorological data is generally needed for model input as part of the air quality analysis. It is important that such data be representative of the atmospheric dispersion and climatological conditions at the site of the proposed source or modification, and at locations where the source may have a significant impact on air quality. For this reason, site specific data are preferable to data collected elsewhere. On-site meteorological monitoring may be required, even when on-site air quality monitoring is not.

The *PSD Monitoring Guideline* should be used to establish locations for any meteorological monitoring network that the applicant may be required to operate and maintain as part of the preconstruction monitoring requirements. That guidance specifies the meteorological instrumentation to be used in measuring meteorological parameters such as wind speed, wind direction, and temperature. The *PSD Monitoring Guideline* also provides that the retrieval of valid wind/stability data should not fall below 90 percent on an annual basis. The type, quantity, and format of the required data will be influenced by the specific input requirements of the dispersion modeling techniques used in the air quality analysis. Therefore, the applicant will need to consult with the permitting agency prior to establishing the required network.

Additional guidance for the collection and use of on-site data is provided in the *PSD Monitoring Guideline*. Also, the EPA documents entitled On-Site Meteorological Program Guidance for Regulatory Modeling Applications (Reference 3), and Volume IV of the series of reports entitled Quality Assurance Handbook for Air Pollution Measurement Systems (Reference 4), contain information required to ensure the quality of the meteorological measurements collected.

IV. DISPERSION MODELING ANALYSIS

Dispersion models are the primary tools used in the air quality analysis. These models estimate the ambient concentrations that will result from the PSD applicant's proposed emissions in combination with emissions from existing sources. The estimated total concentrations are used to demonstrate compliance with any applicable NAAQS or PSD increments. The applicant should consult with the permitting agency to determine the particular requirements for the modeling analysis to assure acceptability of any air quality modeling technique(s) used to perform the air quality analysis contained in the PSD application.

IV.A OVERVIEW OF THE DISPERSION MODELING ANALYSIS

The dispersion modeling analysis usually involves two distinct phases: (1) a ***preliminary analysis*** and (2) a ***full impact analysis***. The ***preliminary analysis*** models only the <u>significant</u> increase in potential emissions of a pollutant from a proposed new source, or the <u>significant</u> net emissions increase of a pollutant from a proposed modification. The results of this preliminary analysis determine whether the applicant must perform a full impact analysis, involving the estimation of background pollutant concentrations resulting from existing sources and growth associated with the proposed source. Specifically, the ***preliminary analysis***:

- *determines whether the applicant can forego further air quality analyses for a particular pollutant*;
- *may allow the applicant to be exempted from the ambient monitoring data requirements* (described in *section III* of this chapter); and
- *is used to define the impact area within which a full impact analysis must be carried out.*

The EPA does not require a full impact analysis for a particular pollutant when emissions of that pollutant from a proposed source or modification would not increase ambient concentrations by more than prescribed significant ambient impact levels, including special Class I significance levels. However, the applicant should check any applicable State or local PSD program requirements in order to determine whether such requirements may contain any different procedures which may be more stringent. In addition, the applicant must still address the requirements for additional impacts required under separate PSD requirements, as described in Chapters D and E which follow this chapter.

A ***full impact analysis*** is required for any pollutant for which the proposed source's estimated ambient pollutant concentrations exceed prescribed significant ambient impact levels. This analysis expands the preliminary analysis in that it considers emissions from:

- *the proposed source*;
- *existing sources*;
- *residential, commercial, and industrial growth that accompanies the new activity at the new source or modification (i.e., secondary emissions).*

For SO_2, particulate matter, and NO_2, the full impact analysis actually consists of separate analyses for the NAAQS and PSD increments. As described later in this section, the selection of background sources (and accompanying emissions) to be modeled for the NAAQS and increment components of the overall analysis proceeds under somewhat different sets of criteria. In general, however, the full impact analysis is used to project ambient pollutant concentrations against which the applicable NAAQS and PSD increments are compared, and to assess the ambient impact of non-criteria pollutants.

The reviewer's primary role is to determine whether the applicant selected the appropriate model(s), used appropriate input data, and followed recommended procedures to complete the air quality analysis. Appendix C in the <u>*Modeling Guideline*</u> provides an example checklist which recommends a standardized set of data to aid the reviewer in determining the completeness and correctness of an applicant's air quality analysis.

Figure C-3 outlines the basic steps for an applicant to follow for a PSD dispersion modeling analysis to demonstrate compliance with the NAAQS and PSD increments. These steps are described in further detail in the sections which follow.

IV.B DETERMINING THE IMPACT AREA

The proposed project's ***impact area*** is the geographical area for which the required air quality analyses for the NAAQS and PSD increments are carried out. This area includes all locations where the significant increase in the potential emissions of a pollutant from a new source, or significant net emissions increase from a modification, will cause a significant ambient impact (i.e., equal or exceed the applicable significant ambient impact level, as shown in *Table C-4)*. The highest modeled pollutant concentration for each averaging time is used to determine whether the source will have a significant ambient impact for that pollutant.

The ***impact area*** is a circular area with a radius extending from the source to (1) the most distant point where approved dispersion modeling predicts a significant ambient impact will occur, or (2) a modeling receptor distance of 50 km, whichever is less. Usually the area of modeled significant impact does not have a continuous, smooth border. (It may actually be comprised of pockets of significant impact separated by pockets of insignificant impact.) Nevertheless, the required air quality analysis is carried out within the circle that circumscribes the significant ambient impacts, as shown in *Figure C-4*.

Initially, for each pollutant subject to review an impact area is determined for every averaging time. The impact area used for the air quality analysis of a particular pollutant is the largest of the areas determined for that pollutant. For example, modeling the proposed SO_2 emissions from a new source might show that a significant ambient SO_2 impact occurs out to a distance from the source of 2 kilometers for the annual averaging period;

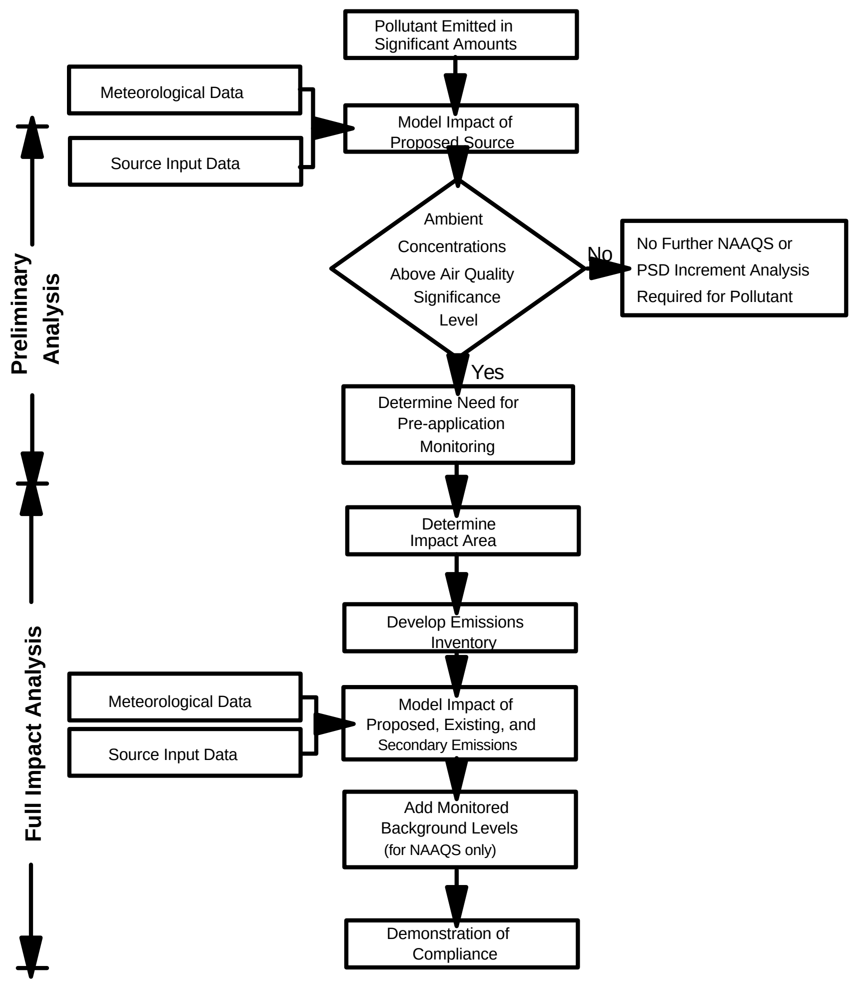

Figure I-C-3. Basic Steps in the Air Quality Analysis
(NAAQS and PSD Increments)

TABLE C-4.

SIGNIFICANCE LEVELS FOR AIR QUALITY IMPACTS IN CLASS II AREAS[a]

Pollutant	Annual	24-hour	8-hour	3-hour	1-hour
SO_2	1	5	-	25	-
TSP	1	5	-	-	-
PM-10	1	5	-	-	-
NO_x	1	-	-	-	-
CO	-	-	500	-	2,000
O_3	-	-	-	-	[b]

[a] This table does not apply to Class I areas. If a proposed source is located within 100 kilometers of a Class I area, an impact of 1 µg/m^3 on a 24-hour basis is significant.

[b] No significant ambient impact concentration has been established. Instead, any net emissions increase of 100 tons per year of VOC subject to PSD would be required to perform an ambient impact analysis.

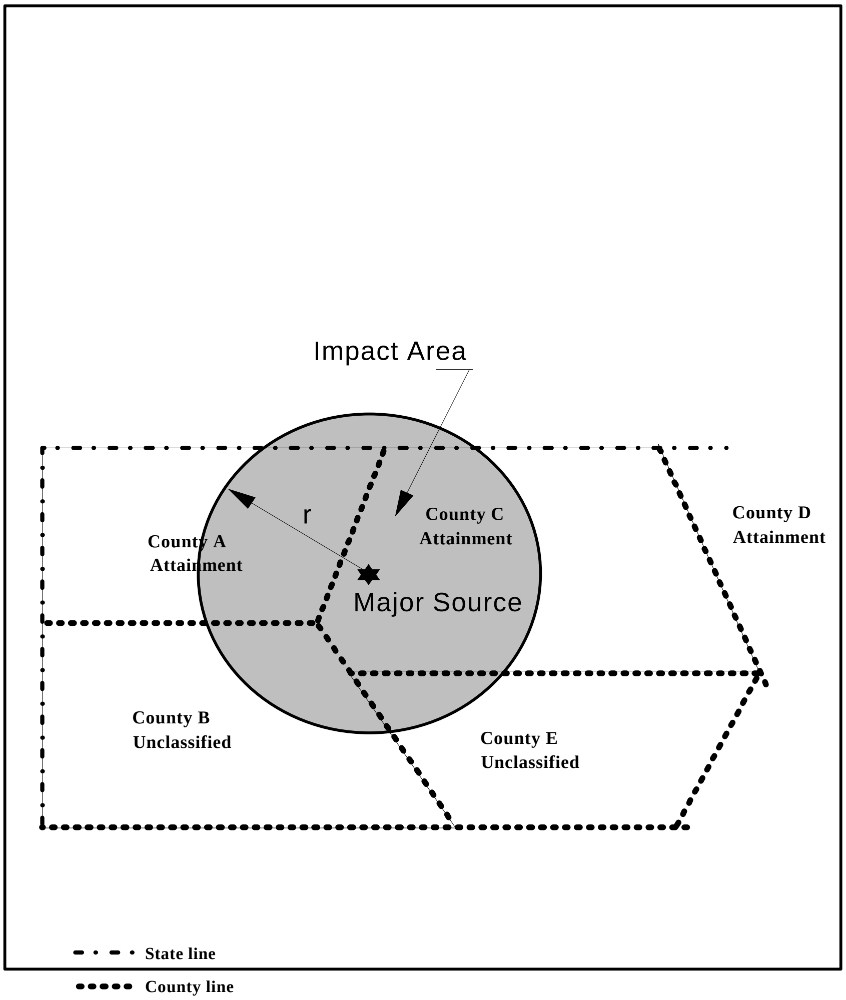

Figure C-4. Determining the Impact Area.

4.3 kilometers for the 24-hour averaging period; and 3.8 kilometers for the 3-hour period. Therefore, an impact area with a radius of 4.3 kilometers from the proposed source is selected for the SO_2 air quality analysis.

In the event that the maximum ambient impact of a proposed emissions increase is below the appropriate ambient air quality significance level for all locations and averaging times, a full impact analysis for that pollutant is not required by EPA. Consequently, a preliminary analysis which predicts an insignificant ambient impact everywhere is accepted by EPA as the required air quality analysis (NAAQS and PSD increments) for that pollutant. ***[NOTE: While it may be shown that no impact area exists for a particular pollutant, the PSD application (assuming it is the first one in the area) still establishes the PSD baseline area and minor source baseline date in the section 107 attainment or unclassifiable area where the source will be located, regardless of its insignificant ambient impact.]***

For each applicable pollutant, the determination of an impact area must include all stack emissions and quantifiable fugitive emissions resulting from the proposed source. For a proposed modification, the determination includes contemporaneous emissions increases and decreases, with emissions decreases input as negative emissions in the model. The EPA allows for the exclusion of temporary emissions (e.g., emissions occurring during the construction phase of a project) when establishing the impact area and conducting the subsequent air quality analysis, if it can be shown that such emissions do not impact a Class I area or an area where a PSD increment for that pollutant is known to be violated. However, where EPA is not the PSD permitting authority, the applicant should confer with the appropriate permitting agency to determine whether it allows for the exclusion of temporary emissions.

Once defined for the proposed PSD project, the impact area(s) will determine the scope of the required air quality analysis. That is, the impact area(s) will be used to

- ! *set the boundaries within which ambient air quality monitoring data may need to be collected,*
- ! *define the area over which a full impact analysis (one that considers the contribution of all sources) must be undertaken,* and
- ! *guide the identification of other sources to be included in the modeling analyses.*

Again, if no significant ambient impacts are predicted for a particular pollutant, EPA does not require further NAAQS or PSD increment analysis of that pollutant. However, the applicant must still consider any additional impacts which the proposed source may have concerning impairment on visibility, soils and vegetation, as well as any adverse impacts on air quality related values in Class I areas (see Chapters D and E of this part).

IV.C SELECTING SOURCES FOR THE PSD EMISSIONS INVENTORIES

When a full impact analysis is required for any pollutant, the applicant is responsible for establishing the necessary inventories of existing sources and their emissions, which will be used to carry out the required NAAQS and PSD increment analyses. Such special emissions inventories contain the various source data used as input to an applicable air quality dispersion model to estimate existing ambient pollutant concentrations. Requirements for preparing an emissions inventory to support a modeling analysis are described to a limited extent in the *Modeling Guideline*. In addition, a number of other EPA documents (e.g., References 5 through 11) contain guidance on the fundamentals of compiling emissions inventories. The discussion which follows pertains primarily to identifying and selecting existing sources to be included in a PSD emissions inventory as needed for a full impact analysis.

The permitting agency may provide the applicant a list of existing sources upon request once the extent of the impact area(s) is known. If the list includes only sources above a certain emissions threshold, the applicant is responsible for identifying additional sources below that emissions level which could affect the air quality within the impact area(s). The permitting agency should review all required inventories for completeness and accuracy.

IV.C.1 THE NAAQS INVENTORY

While air quality data may be used to help identify existing background air pollutant concentrations, EPA requires that, at a minimum, all nearby sources be explicitly modeled as part of the NAAQS analysis. The *Modeling Guideline* defines a "nearby" source as any point source expected to cause a significant concentration gradient in the vicinity of the proposed new source or modification. For PSD purposes, "vicinity" is defined as the impact area. However, the location of such nearby sources could be anywhere within the impact area or an annular area extending 50 kilometers beyond the impact area. (See *Figure C-5.*)

In determining which existing point sources constitute nearby sources, the *Modeling Guideline* necessarily provides flexibility and requires judgment to be exercised by the permitting agency. Moreover, the screening method for identifying a nearby source may vary from one permitting agency to another. To identify the appropriate method, the applicant should confer with the permitting agency prior to actually modeling any existing sources.

The *Modeling Guideline* indicates that the useful distance for guideline models is 50 kilometers. Occasionally, however, when applying the above source identification criteria, existing stationary sources located in the annular area beyond the impact area may be more than 50 kilometers from portions of the impact area. When this occurs, such sources' modeled impacts throughout the entire impact area should be calculated. That is, special steps should not be taken to cut off modeled impacts of existing sources at receptors within the applicants impact area merely because the receptors are

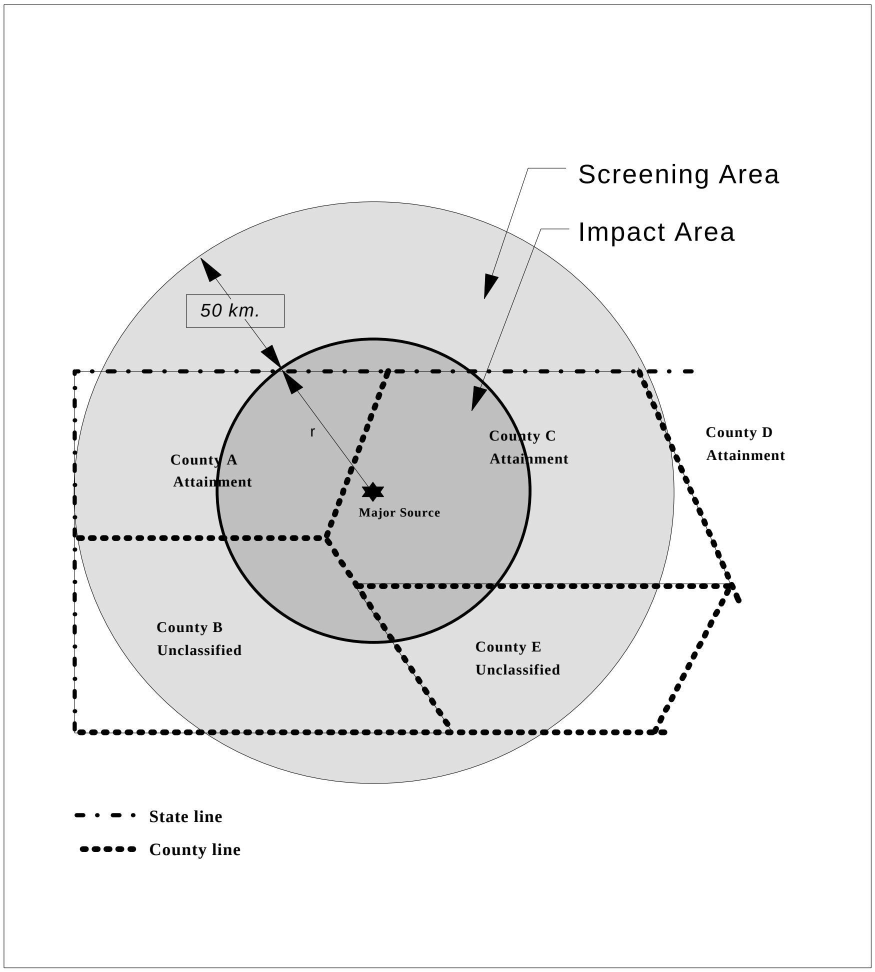

Figure C-5
Defining the Emissions Inventory Screening Area.

located beyond 50 kilometers from such sources. Modeled impacts beyond 50 kilometers should be considered as conservative estimate in that they tend to overestimate the true source impacts. Consequently, if it is found that an existing source's impact include estimates at distances exceeding the normal 50-kilometer range, it may be appropriate to consider other techniques, including long-range transport models. Applicants should consult with the permitting agency prior to the selection of a model in such cases.

It will be necessary to include in the NAAQS inventory those sources which have received PSD permits but have not yet not begun to operate, as well as any complete PSD applications for which a permit has not yet been issued. In the latter case, it is EPA's policy to account for emissions that will occur at sources whose complete PSD application was submitted as of thirty days prior to the date the proposed source files its PSD application. Also, sources from which secondary emissions will occur as a result of the proposed source should be identified and evaluated for inclusion in the NAAQS inventory. While existing mobile source emissions are considered in the determination of background air quality for the NAAQS analysis (typically using existing air quality data), it should be noted that the applicant need not model estimates of future mobile source emissions growth that could result from the proposed project because the definition of "secondary emissions" specifically excludes any emissions coming directly from mobile sources.

Air quality data may be used to establish background concentrations in the impact area resulting from existing sources that are not considered as nearby sources (e.g., area and mobile sources, natural sources, and distant point sources). If, however, adequate air quality data do not exist (and the applicant was not required to conduct pre-application monitoring), then these "other" background sources are also included in the NAAQS inventory so that their ambient impacts can be estimated by dispersion modeling.

IV.C.2 THE INCREMENT INVENTORY

An emissions inventory for the analysis of affected PSD increments must also be developed. The increment inventory includes all increment-affecting sources located in the impact area of the proposed new source or modification. Also, all increment-affecting sources located within 50 kilometers of the impact area (see *Figure C-5*) are included in the inventory if they, either individually or collectively, affect the amount of PSD increment consumed. The applicant should contact the permitting agency to determine what particular procedures should be followed to identify sources for the increment inventory.

In general, the stationary sources of concern for the increment inventory are those stationary sources with actual emissions changes occurring since the <u>minor source baseline date</u>. However, it should be remembered that certain actual emissions changes occurring before the minor source baseline date (i.e., at major stationary point sources) also affect the increments. Consequently, the types of stationary point sources that are initially reviewed to determine the need to include them in the increment inventory fall under two specific time frames as follows:

<u>After the major source baseline date-</u>

! *existing <u>major</u> stationary sources having undergone a physical change or change in their method of operation*; and

! *new <u>major</u> stationary sources.*

<u>After the minor source baseline date-</u>

! *existing stationary sources having undergone a physical change or change in their method of operation*;

! *existing stationary sources having increased hours of operation or capacity utilization (unless such change was considered representative of baseline operating conditions)*; and

! *new stationary sources.*

If, in the impact area or surrounding screening area, area or mobile source emissions will affect increment consumption, then emissions input data for such minor sources are also included in the increment inventory. The change in such emissions since the minor source baseline date (rather than the absolute magnitude of these emissions) is of concern since this change is what may affect a PSD increment. Specifically, the rate of growth and the amount of elapsed time since the minor source baseline date was established determine the extent of the increase in area and mobile source emissions. For example, in an area where the minor source baseline date was recently established (e.g., within the past year or so of the proposed PSD project), very little area and mobile source emissions growth may have occurred. Also, sufficient data (particularly mobile source data) may not yet be available to reflect the amount of growth that has taken place. As with the NAAQS analysis, applicants are not required to estimate future mobile source emissions growth that could result from the proposed project because they are excluded from the definition of "secondary emissions."

The applicant should initially consult with the permitting agency to determine the availability of data for assessing area and mobile source growth since the minor source baseline date. This information, or the fact that such data is not available, should be thoroughly documented in the application. The permitting agency should verify and approve the basis for actual area source emissions estimates and, especially if these estimates are considered by the applicant to have an insignificant impact, whether it agrees with the applicant's assessment.

When area and mobile sources are determined to affect any PSD increment, their emissions must be reported on a gridded basis. The grid should cover the entire impact area and any areas outside the impact area where area and mobile source emissions are included in the analysis. The exact sizing of an emissions inventory grid cell generally should be based on the emissions density in the area and any computer constraints that may exist. Techniques for assigning area source emissions to grid cells are provided in Reference 11. The grid layout should always be discussed with, and approved by, the permitting agency in advance of its use.

IV.C.3 NONCRITERIA POLLUTANTS INVENTORY

An inventory of all noncriteria pollutants emitted in significant amounts is required for estimating the resulting ambient concentrations of those pollutants. Significant ambient impact levels have not been established for non-criteria pollutants. Thus, an impact area cannot be defined for non-criteria pollutants in the same way as for criteria pollutants. Therefore, as a general rule of thumb, EPA believes that an emissions inventory for non-criteria pollutants should include sources within 50 kilometers of the proposed source. Some judgment will be exercised in applying this position on a case-by-case basis.

IV.D MODEL SELECTION

Two levels of model sophistication exist: screening and refined dispersion modeling. Screening models may be used to eliminate more extensive modeling for either the preliminary analysis phase or the full impact analysis phase, or both. However, the results must demonstrate to the satisfaction of the permitting agency that all applicable air quality analysis requirements are met. Screening models produce conservative estimates of ambient impact in order to reasonably assure that maximum ambient concentrations will not be underestimated. If the resulting estimates from a screening model indicate a threat to a NAAQS or PSD increment, the applicant uses a refined model to re-estimate ambient concentrations (of course, the applicant can select other options, such as reducing emissions, or to decrease impacts). Guidance on the use of screening procedures to estimate the air quality impact of stationary sources is presented in EPA's <u>Screening Procedures for Estimating Air Qaulity Impact of Stationary Sources</u> [Reference 12].

A refined dispersion model provides more accurate estimates of a source's impact and, consequently, requires more detailed and precise input data than does a screening model. The applicant is referred to *Appendix A* of the *<u>Modeling Guideline</u>* for a list of EPA-preferred models, i.e., *guideline models*. The guideline model selected for a particular application should be the one which most accurately represents atmospheric transport, dispersion, and chemical transformations in the area under analysis. For example, models have been developed for both simple and complex terrain situations; some are designed for urban applications, while others are designed for rural applications.

In many circumstances the guideline models known as Industrial Source Complex Model Short- and Long-term (ISCST and ISCLT, respectively) are acceptable for stationary sources and are preferred for use in the dispersion modeling analysis. A brief discussion of options required for regulatory applications of the ISC model is contained in the *Modeling Guideline*. Other guideline models, such as the Climatological Dispersion Model (CDM), may be needed to estimate the ambient impacts of area and mobile sources.

Under certain circumstances, refined dispersion models that are not listed in the *Modeling Guideline*, i.e., *non-guideline models*, may be considered for use in the dispersion modeling analysis. The use of a non-guideline model for a PSD permit application must, however, be pre-approved on a case-by-case basis by EPA. The applicant should refer to the EPA documents entitled Interim Procedures for Evaluating Air Quality Models (Revised) [Reference 13] and Interim Procedures for Evaluating Air Quality Models: Experience with Implementation [Reference 14]. Close coordination with EPA and the appropriate State or local permitting agency is essential if a non-guideline model is to be used successfully.

IV.D.1 METEOROLOGICAL DATA

Meteorological data used in air quality modeling must be spatially and climatologically (temporally) representative of the area of interest. Therefore, an applicant should consult the permitting authority to determine what data will be most representative of the location of the applicant's proposed facility.

Use of site-specific meteorological data is preferred for air quality modeling analyses if 1 or more years of quality-assured data are available. If at least 1 year of site-specific data is not available, 5 years of meteorological data from the nearest National Weather Service (NWS) station can be used in the modeling analysis. Alternatively, data from universities, the Federal Aviation Administration, military stations, industry, and State or local air pollution control agencies may be used if such data are equivalent in accuracy and detail to the NWS data, and are more representative of the area of concern.

The 5 years of data should be the most recent consecutive 5 years of meteorological data available. This 5-year period is used to ensure that the model results adequately reflect meteorological conditions conducive to the prediction of maximum ambient concentrations. The NWS data may be obtained from the National Climatic Data Center (Asheville, North Carolina), which serves as a clearinghouse to collect and distribute meteorological data collected by the NWS.

IV.D.2 RECEPTOR NETWORK

Polar and Cartesian networks are two types of receptor networks commonly used in refined air dispersion models. A ***polar network*** is comprised of concentric rings and radial arms extending outward from a center point (e.g., the modeled source). Receptors are located where the concentric rings and radial arms intersect. Particular care should be exercised in using a polar network to identify maximum estimated pollutant concentrations because of the inherent problem of increased longitudinal spacing of adjacent receptors as their distance along neighboring radial arms increases. For example, as illustrated in *Figure C-6*, while the receptors on individual radials, e.g., *A1, A2, A3*... and *B1, B2, B3*..., may be uniformly spaced at a distance of 1 kilometer apart, at greater distances from the proposed source, the longitudinal distance between the receptors, e.g., *A4* and *B4*, on neighboring radials may be several kilometers. As a result of the presence of larger and larger "blind spots" between the radials as the distance from the modeled source increases, finding the maximum source impact can be somewhat problematic. For this reason, using a polar network for anything other than initial screening is generally discouraged.

A ***cartesian network*** (also referred to as a rectangular network) consists of north-south and east-west oriented lines forming a rectangular grid, as shown in *Figure C-6*, with receptors located at each intersection point. In most refined air quality analyses, a cartesian grid with from 300 to 400 receptors (where the distance from the source to the farthest receptor is 10 kilometers) is usually adequate to identify areas of maximum concentration. However, the total number of receptors will vary based on the specific air quality analysis performed.

In order to locate the maximum modeled impact, perform multiple model runs, starting with a relatively coarse receptor grid (e.g., one or two kilometer spacing) and proceeding to a relatively fine receptor grid (e.g., 100 meters). The fine receptor grid should be used to focus on the area(s) of higher estimated pollutant concentrations identified by the coarse grid model runs. With such multiple runs the maximum modeled concentration can be identified. It is the applicant's responsibility to demonstrate that the final receptor network is sufficiently compact to identify the maximum estimated pollutant concentration for each applicable averaging period. This applies both to the PSD increments and to the NAAQS.

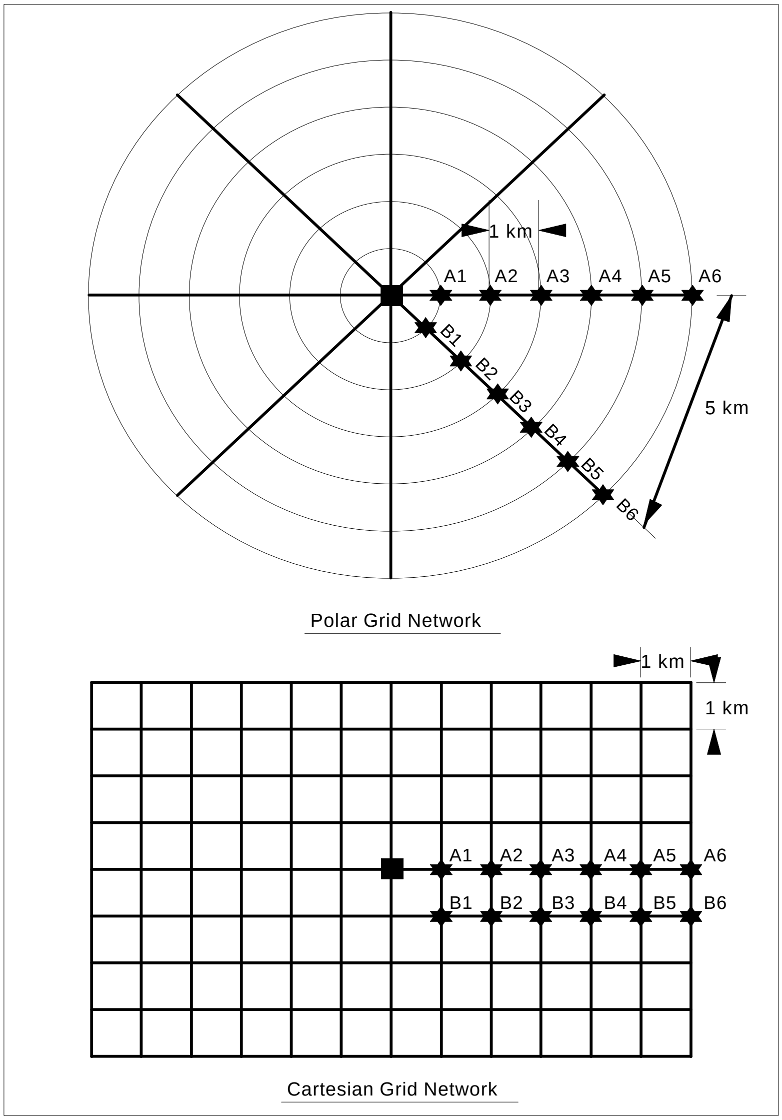

Figure C-6. Examples of Polar and Cartesian Grid Networks.

Some air quality models allow the user to input discrete receptors at user-specified locations. The selection of receptor sites should be a case-by-case determination, taking into consideration the topography, the climatology, the monitor sites, and the results of the preliminary analysis. For example, receptors should be located at:

- *the fenceline of a proposed facility*;
- *the boundary of the nearest Class I or nonattainment area*;
- *the location(s) of ambient air monitoring sites*; and
- *locations where potentially high ambient air concentrations are expected to occur*.

In general, modeling receptors for both the NAAQS and the PSD increment analyses should be placed at ground level points anywhere except on the applicant's plant property if it is inaccessible to the general public. Public access to plant property is to be assumed, however, unless a continuous physical barrier, such as a fence or wall, precludes entrance onto that property. In cases where the public has access, receptors should be located on the applicant's property. It is important to note that ground level points of receptor placement could be over bodies of water, roadways, and property owned by other sources. For NAAQS analyses, modeling receptors may also be placed at elevated locations, such as on building rooftops. However, for PSD increments, receptors are limited to locations at ground level.

IV.D.3 GOOD ENGINEERING PRACTICE (GEP) STACK HEIGHT

Section 123 of the Clean Air Act limits the use of dispersion techniques, such as merged gas streams, intermittent controls, or stack heights above GEP, to meet the NAAQS or PSD increments. The GEP stack height is defined under Section 123 as "the height necessary to insure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies or wakes which may be created by the source itself, nearby structures or nearby terrain obstacles." The EPA has promulgated stack height regulations under 40 CFR Part 51 which help to determine the GEP stack height for any stationary source.

Three methods are available for determining "GEP stack height" as defined in 40 CFR 51.100(ii):

- ! *use the 65 meter (213.5 feet) de minimis height as measured from the ground-level elevation at the base of the stack;*

- ! *calculate the refined formula height using the dimensions of nearby structures (this height equals H + 1.5L, where H is the height of the nearby structure and L is the lesser dimension of the height or projected width of the nearby structure); or*

- ! *demonstrate by a fluid model or field study the equivalent GEP formula height that is necessary to avoid excessive concentrations caused by atmospheric downwash, wakes, or eddy effects by the source, nearby structures, or nearby terrain features.*

That portion of a stack height in excess of the GEP height is generally not creditable when modeling to develop source emissions limitations or to determine source impacts in a PSD air quality analysis. For a stack height less than GEP height, screening procedures should be applied to assess potential air quality impacts associated with building downwash. In some cases, the aerodynamic turbulence induced by surrounding buildings will cause stack emissions to be mixed rapidly toward the ground (downwash), resulting in higher-than-normal ground level concentrations in the vicinity of the source. Reference 12 contain screening procedures to estimate downwash concentrations in the building wake region. The *Modeling Guideline* recommends using the Industrial Source Complex (ISC) air dispersion model to determine building wake effects on maximum estimated pollutant concentrations.

For additional guidance on creditable stack height and plume rise calculations, the applicant should consult with the permitting agency. In addition, several EPA publications [References 15 through 19] are available for the applicant's review.

IV.D.4 SOURCE DATA

Emissions rates and other source-related data are needed to estimate the ambient concentrations resulting from (1) the proposed new source or modification, and (2) existing sources contributing to background pollutant concentrations (NAAQS and PSD increments). Since the estimated pollutant concentrations can vary widely depending on the accuracy of such data, the most appropriate source data available should always be selected for use in a modeling analysis. Guidance on the identification and selection of existing sources for which source input data must be obtained for a PSD air quality analysis is provided in *section IV.C.* Additional information on the specific source input data requirements is contained in EPA's *Modeling Guideline* and in the users' guide for each dispersion model.

Source input data that must be obtained will depend upon the categorization of the source(s) to be modeled as either a point, area or line source. Area sources are often collections of numerous small emissions sources that are impractical to consider as separate point or line sources. Line sources most frequently considered are roadways.

For each stationary point source to be modeled, the following minimum information is generally necessary:

- *pollutant emission rate (see discussion below)*;
- *stack height (see discussion on GEP stack height)*;
- *stack gas exit temperature, stack exit inside diameter, and stack gas exit velocity*;
- *dimensions of all structures in the vicinity of the stack in question*;
- *the location of topographic features (e.g., large bodies of water, elevated terrain) relative to emissions points*; and
- *stack coordinates*.

A source's ***emissions rate*** as used in a modeling analysis for any pollutant is determined from the following source parameters (where MMBtu means "million Btu's heat input"):

- ***emissions limit*** *(e.g., lb/MMBtu)*;
- ***operating level*** *(e.g., MMBtu/hour)*; and
- ***operating factor*** *(e,g., hours/day, hours/year)*.

Special procedures, as described below, apply to the way that each of these parameters is used in calculating the emissions rate for either the proposed new source (or modification) or any existing source considered in the NAAQS and PSD increment analyses. *Table C-5* provides a summary of the point source emissions input data requirements for the NAAQS inventory.

For both NAAQS and PSD increment compliance demonstrations, the ***emissions rate*** for the proposed new source or modification must reflect the <u>maximum allowable</u> operating conditions as expressed by the federally enforceable ***emissions limit***, ***operating level***, and ***operating factor*** for each applicable pollutant and averaging time. The applicant should base the emissions rates on the results of the BACT analysis (see *Chapter B, Part I*). ***Operating levels*** less than 100 percent of capacity may also need to be modeled where differences in stack parameters associated with the lower operating levels could result in higher ground level concentrations. A value representing less than continuous operation (8760 hours per year) should be used for the ***operating factor*** only when a federally enforceable operating limitation is placed upon the proposed source. [NOTE: It is important that the applicant demonstrate that all modeled emission rates are consistent with the applicable permit conditions.]

TABLE C-5 POINT SOURCE MODEL INPUT DATA (EMISSIONS) FOR NAAQS COMPLIANCE DEMONSTRATIONS

Averaging Time	Emission Limit (#/MMBtu)[1]	X	Operating Level (MMBtu/hr)[1]	X	Operating Factor (e.g., hr/yr, hr/day)
Proposed Major New or Modified Source					
Annual and quarterly	Maximum allowable emission limit or Federally enforceable permit		Design capacity or Federally enforceable permit condition		Continuous operation (i.e, 8760 hours)[2]
Short term (24 hours or less)	Maximum allowable emission limit or Federally enforceable permit limit		Design capacity or Federally enforceable permit condition[3]		Continuous operation (i.e., all hours of each time period under consideration) (for all hours of the meteorological data base)[2]
Nearby Background Source(s)[4]					
Annual and quarterly	Maximum allowable emission limit or Federally enforceable permit		Actual or design capacity (whichever is greater), or Federally enforceable permit condition		Actual operating factor averaged over the most recent 2 years[5]
Short term	Maximum allowable emission limit or Federally enforceable permit limit		Actual or design capacity (whichever is greater), or Federally enforceable permit condition[3]		Continuous operation (i.e., all hours of each time period under consideration) (for all hours of the meteorological data base)[2]
Other Background Source(s)[6]					
Annual and quarterly	Maximum allowable emission limit or Federally enforceable permit limit		Annual level when actually operating, averaged over the most recent 2 years[5]		Actual operating factor averaged over the most recent 2 years[5]
Short term	Maximum allowable emission limit or Federally enforceable permit limit		Annual level when actually operating, averaged over the most recent 2 years[5]		Continuous operation (i.e., all hours of each time period under consideration) (for all hours of the meteorological data base)[2]

[1] Terminology applicable to fuel burning sources; analogous terminology (e.g., #/throughput) may be used for other types of sources.
[2] If operation does not occur for all hours of the time period of consideration (e.g., 3 or 24 hours) and the source operation is constrained by a Federally enforceable permit condition, an appropriate adjustment to the modeled emission rate may be made (e.g., if operation is only 8:00 a.m. to 4:00 p.m. each day, only these hours will be modeled with emissions from the source. Modeled emissions should not be averaged across non-operating time periods).
[3] Operating levels such as 50 percent and 75 percent of capacity should also be modeled to determine the load causing the highest concentration.
[4] Includes existing facility to which modification is proposed if the emissions from the existing facility will not be affected by the modification. Otherwise use same parameters as for major modification.
[5] Unless it is determined that this period is not representative.
[6] Generally, the ambient impacts from non-nearby background sources can be represented by air quality data unless adequate data do not exist.

For those existing point sources that must be explicitly modeled, i.e., "nearby" sources (see *section IV.C.1* of this chapter), the NAAQS inventory must contain the maximum allowable values for the ***emissions limit***, and ***operating level***. The ***operating factor*** may be adjusted to account for representative, historical operating conditions only when modeling for the annual (or quarterly for lead [Pb]) averaging period. In such cases, the appropriate input is the actual ***operating factor*** averaged over the most recent 2 years (unless the permitting agency determines that another period is more representative). For short-term averaging periods (24 hours or less), the applicant generally should assume that nearby sources operate continuously. However, the ***operating factor*** may be adjusted to take into account any federally enforceable permit condition which limits the allowable hours of operation. In situations where the actual ***operating level*** exceeds the design capacity (considering any federally enforceable limitations), the actual level should be used to calculate the ***emissions rate.***

If other background sources need to be modeled (i.e., adequate air quality data are not available to represent their impact), the input requirements for the ***emissions limit*** and ***operating factor*** are identical to those for "nearby" sources. However, input for the ***operating level*** may be based on the annual level of actual operation averaged over the last 2 years (unless the permitting agency determines that a more representative period exists).

The applicant must also include any quantifiable **fugitive emissions** from the proposed source or any nearby sources. Fugitive emissions are those emissions that cannot reasonably be expected to pass through a stack, vent, or other equivalent opening, such as a chimney or roof vent. Common quantifiable fugitive emissions sources of particulate matter include coal piles, road dust, quarry emissions, and aggregate stockpiles. Quantifiable fugitive emissions of volatile organic compounds (VOC) often occur at components of process equipment. An applicant should consult with the permitting agency to determine the proper procedures for characterizing and modeling fugitive emissions.

When building **downwash** affects the air quality impact of the proposed source or any existing source which is modeled for the NAAQS analysis, those impacts generally should be considered in the analysis. Consequently, the appropriate dimensions of all structures around the stack(s) in question also should be included in the emissions inventory. Information including building heights and horizontal building dimensions may be available in the permitting agency's files; otherwise, it is usually the responsibility of the applicant to obtain this information from the applicable source(s).

Sources should not automatically be excluded from downwash considerations simply because they are located <u>outside</u> the impact area. Some sources located just outside the impact area may be located close enough to it that the immediate downwashing effects directly impact air quality in the impact area. In addition, the difference in downwind plume concentrations caused by the downwash phenomenon may warrant consideration within the impact area even when the immediate downwash effects do not. Therefore, any decision by the applicant to exclude the effects of downwash for a particular source should be justified in the application, and approved by the permitting agency.

For a PSD increment analysis, an estimate of the amount of increment consumed by existing point sources generally is based on increases in <u>actual</u> emissions occurring since the minor source baseline date. The exception, of course, is for major stationary sources whose <u>actual</u> emissions have increased (as a result of construction) before the minor source baseline date but on or after the major source baseline date. For any increment-consuming (or increment-expanding) emissions unit, the actual ***emissions limit***, ***operating level***, and ***operating factor*** may all be determined from source records and other information (e.g., State emissions files), when available, reflecting actual source operation. For the annual averaging period, the change in the actual ***emissions rate*** should be calculated as the difference between:

- *the current average actual* ***emissions rate***, and
- *the average actual* ***emissions rate*** *as of the minor source baseline date (or major source baseline date for major stationary sources).*

In each case, the average rate is calculated as the average over previous 2-year period (unless the permitting agency determines that a different time period is more representative of normal source operation).

For each short-term averaging period (24 hours and less), the change in the actual ***emissions rate*** for the particular averaging period is calculated as the difference between:

- ! *the current maximum actual **emissions rate**, and*
- ! *the maximum actual **emissions rate** as of the minor source baseline date (or major source baseline date for applicable major stationary sources undergoing consturction before the minor source baseline date).*

In each case, the maximum rate is the highest occurrence for that averaging period during the previous 2 years of operation.

Where appropriate, air quality impacts from **fugitive emissions** and **building downwash** are also taken into account for the PSD increment analysis. Of course, they would only be considered when applicable to increment-consuming emissions.

If the change in the actual emissions rate at a particular source involves a change in stack parameters (e.g., stack height, gas exit temperature, etc.) then the stack parameters and emissions rates associated with both the baseline case and the current situation must be used as input to the dispersion model. To determine increment consumption (or expansion) for such a source, the baseline case emissions are input to the model as negative emissions, along with the baseline stack parameters. In the same model run, the current case for the same source is modeled as the total current emissions associated with the current stack parameters. This procedure effectively calculates, for each receptor and for each averaging time, the difference between the baseline concentration and the current concentration (i.e., the amount of increment consumed by the source).

Emissions changes associated with area and mobile source growth occurring since the minor source baseline date are also accounted for in the increment analysis by modeling. In many cases state emission files will contain information on area source emissions or such information may be available from EPA's AIRS-NEDS emissions data base. In the absence of this information, the applicant should use procedures adopted for developing state area source emission inventories. The EPA documents outlining procedures for area source inventory development should be reviewed.

Mobile source emissions are usually calculated by applying mobile source emissions factors to transportation data such as vehicle miles travelled (VMT), trip ends, vehicle fleet characteristics, etc. Data are also required on the spatial arrangement of the VMT within the area being modeled. Mobile source emissions factors are available for various vehicle types and conditions from an EPA emissions factor model entitled MOBILE4. The MOBILE4 users manual [Reference 20] should be used in developing inputs for executing this model. The permitting agency can be of assistance in obtaining the needed mobile source emissions data. Oftentimes, these data are compiled by the permitting agency acting in concert with the local planning agency or transportation department.

For both area source and mobile source emissions, the applicant will need to collect data for the minor source baseline date and the current situation. Data from these two dates will be required to calculate the increment-affecting emission changes since the minor source baseline date.

IV.E THE COMPLIANCE DEMONSTRATION

An applicant for a PSD permit must demonstrate that the proposed source will not cause or contribute to air pollution in violation of any NAAQS or PSD increment. This compliance demonstration, for each affected pollutant, must result in one of the following:

- ***The proposed new source or modification will not cause a significant ambient impact anywhere.***

If the significant net emissions increase from a proposed source would not result in a significant ambient impact anywhere, the applicant is usually not required to go beyond a preliminary analysis in order to make the necessary showing of compliance for a particular pollutant. In determining the ambient impact for a pollutant, the <u>highest</u> estimated ambient concentration of that pollutant for each applicable averaging time is used.

- ***The proposed new source or modification, in conjunction with existing sources, will not cause or contribute to a violation of any NAAQS or PSD increment.***

In general, compliance is determined by comparing the predicted ground level concentrations (based on the full impact analysis and existing air quality data) at each model receptor to the applicable NAAQS and PSD increments. If the predicted pollutant concentration increase over the baseline concentration is below the applicable increment, and the predicted total ground level concentrations are below the NAAQS, then the applicant has successfully demonstrated compliance.

The modeled concentrations which should be used to determine compliance with any NAAQS and PSD increment depend on 1) the type of standard, i.e., deterministic or statistical, 2) the available length of record of meteorological data, and 3) the averaginign time of the standard being analyzed. For example, when the analysis is based on 5 years of National Weather Service meteorological data, the following estimates should be used:

- for deterministically based standards (e.g., SO_2), the highest, second-highest short term estimate and the highest annual estimate; and

- for statistically based standards (e.g., PM-10), the highest, sixth-highest estimate and highest 5-year average estimate.

Further guidance to determine the appropriate estimates to use for the compliance determination is found in *Chapter 8* of the ***Modeling Guideline*** for SO_2, TSP, lead, NO_2, and CO; and in EPA's **PM-10 SIP Development Guideline** [Reference 21] for PM-10.

When a violation of any NAAQS or increment is predicted at one or more receptors in the impact area, the applicant can determine whether the net emissions increase from the proposed source will result in a significant ambient impact at the point (receptor) of each predicted violation, and at the time the violation is predicted to occur. The source will not be considered to cause or contribute to the violation if its own impact is not significant at any violating receptor at the time of each predicted violation. In such a case, the permitting agency, upon verification of the demonstration, may approve the permit. However, the agency must also take remedial action through applicable provisions of the state implementation plan to address the predicted violation(s).

- ***The proposed new source or modification, in conjunction with existing sources, will cause or contribute to a violation, but will secure sufficient emissions reductions to offset its adverse air quality impact.***

If the applicant cannot demonstrate that only insignificant ambient impacts would occur at violating receptors (at the time of the predicted violation), then other measures are needed before a permit can be issued. Somewhat different procedures apply to NAAQS violations than to PSD increment violations. For a **NAAQS violation** to which an applicant contributes significantly, a PSD permit may be granted only if sufficient emissions reductions are obtained to compensate for the adverse ambient impacts caused by the proposed source. Emissions reductions are considered to compensate for the proposed source's adverse impact when, at a minimum, (1) the modeled net concentration, resulting from the proposed emissions increase and the federally enforceable emissions reduction, is less than the applicable significant ambient impact level at each affected receptor, and (2) no new violations will occur. Moreover, such emissions reductions must be made federally enforceable in order to be acceptable for providing the air quality offset. States may adopt procedures pursuant to federal regulations at 40 CFR 51.165(b) to enable the permitting of sources whose emissions would cause or contribute to a NAAQS violation anywhere. The applicant should determine what specific provisions exist within the State program to deal with this type of situation.

In situations where a proposed source would cause or contribute to a **PSD increment violation**, a PSD permit cannot be issued until the increment violation is entirely corrected. Thus, when the proposed source would cause a new increment violation, the applicant must obtain emissions reductions that are sufficient to offset enough of the source's ambient impact to avoid the violation. In an area where an increment violation already exists, and the proposed source would significantly impact that violation, emissions reductions must not only offset the source's adverse ambient impact, but must be sufficient to alleviate the PSD increment violation, as well.

V. AIR QUALITY ANALYSIS -- EXAMPLE

This section presents a hypothetical example of an air quality analysis for a proposed new PSD source. In reality, no two analyses are alike, so an example that covers all modeling scenarios is not possible to present. However, this example illustrates several significant elements of the air quality analysis, using the procedures and information set forth in this chapter.

An applicant is proposing to construct a new coal-fired, steam electric generating station. Coal will be supplied by railroad from a distant mine. The coal-fired plant is a new major source which has the potential to emit significant amounts of SO_2, PM (particulate matter emissions and PM-10 emissions), NO_x, and CO. Consequently, an air quality analysis must be carried out for each of these pollutants. In this analysis, the applicant is required to demonstrate compliance with respect to -

- the ***NAAQS*** for SO_2, PM-10, NO_2, and CO, and
- the ***PSD increments*** for SO_2, TSP, and NO_2.

V.A DETERMINING THE IMPACT AREA

The first step in the air quality analysis is to estimate the ambient impacts caused by the proposed new source itself. This preliminary analysis establishes the impact area for each pollutant emitted in significant amounts, and for each averaging period. The largest impact area for each pollutant is then selected as the impact area to be used in the full impact analysis.

To begin, the applicant prepares a modeling protocol describing the modeling techniques and data bases that will be applied in the preliminary analysis. These modeling procedures are reviewed in advance by the permitting agency and are determined to be in accordance with the procedures described in the *Modeling Guideline* and the stack height regulations.

Several pollutant-emitting activities (i.e., emissions units) at the source will emit pollutants subject to the air quality analysis. The two main boilers emit particulate matter (i.e., particulate matter emissions and PM-10 emissions), SO_2, NO_x, and CO. A standby auxiliary boiler also emits these pollutants, but will only be permitted to operate when the main boilers are not operating.

Particulate matter emissions and PM-10 emissions will also occur at the coal-handling operations and the limestone preparation process for the flue gas desulfurization (FGD) system. Emissions units associated with coal and limestone handling include:

- ! *Point sources--the coal car dump, the fly ash silos, and the three coal baghouse collectors*;
- ! *Area sources--the active and the inactive coal storage piles and the limestone storage pile*; and
- ! *Line sources--the coal and limestone conveying operation*.

The emissions from all of the emissions units at the proposed source are then modeled to estimate the source's area of significant impact (impact area) for each pollutant. The results of the preliminary analysis indicate that significant ambient concentrations of NO_2 and SO_2 will occur out to distances of 32 and 50 kilometers, respectively, from the proposed source. No significant concentrations of CO are predicted at any location outside the fenced-in property of the proposed source. Thus, an impact area is not defined for CO, and no further CO analysis is required.

Particulate matter emissions from the coal-handling operations and the limestone preparation process result in significant ambient TSP concentrations out to a distance of 2.2 kilometers. However, particulate matter emissions from the boiler stacks will cause significant TSP concentrations for a distance of up to 10 kilometers. Since the boiler emissions of particulate matter are predominantly PM-10 emissions, the same impact area is used for both TSP and PM-10.

This preliminary analysis further indicates that pre-application monitoring data may be required for two of the criteria pollutants, SO_2 and NO_2, since the proposed new source will cause ambient concentrations exceeding the prescribed significant monitoring concentrations for these two pollutants (see *Table C-3*). Estimated concentrations of PM-10 are below the significant monitoring concentration. The permitting agency informs the applicant that the requirement for pre-application monitoring data will not be imposed with regard to PM-10. However, due to the fact that existing ambient concentrations of both SO_2 and NO_2 are known to exceed their respective significant monitoring concentrations, the applicant must address the pre-application monitoring data requirements for these pollutants.

Before undertaking a site-specific monitoring program, the applicant investigates the availability of existing data that is representative of air quality in the area. The permitting agency indicates that an agency-operated SO_2 network exists which it believes would provide representative data for the applicant's use. It remains for the applicant to demonstrate that the existing air quality data meet the EPA criteria for data sufficiency, representativeness, and quality as provided in the *PSD Monitoring Guideline*. The applicant proceeds to provide a demonstration which is approved by the permitting agency. For NO_2, however, adequate data do not exist, and it is necessary for the applicant to take responsibility for collecting such data. The applicant consults with the permitting agency in order to develop a monitoring plan and subsequently undertakes a site-specific monitoring program for NO_2.

In this example, four intrastate counties are covered by the applicant's impact area. Each of these counties, shown in *Figure C-7*, is designated attainment for all affected pollutants. Consequently, a NAAQS and PSD

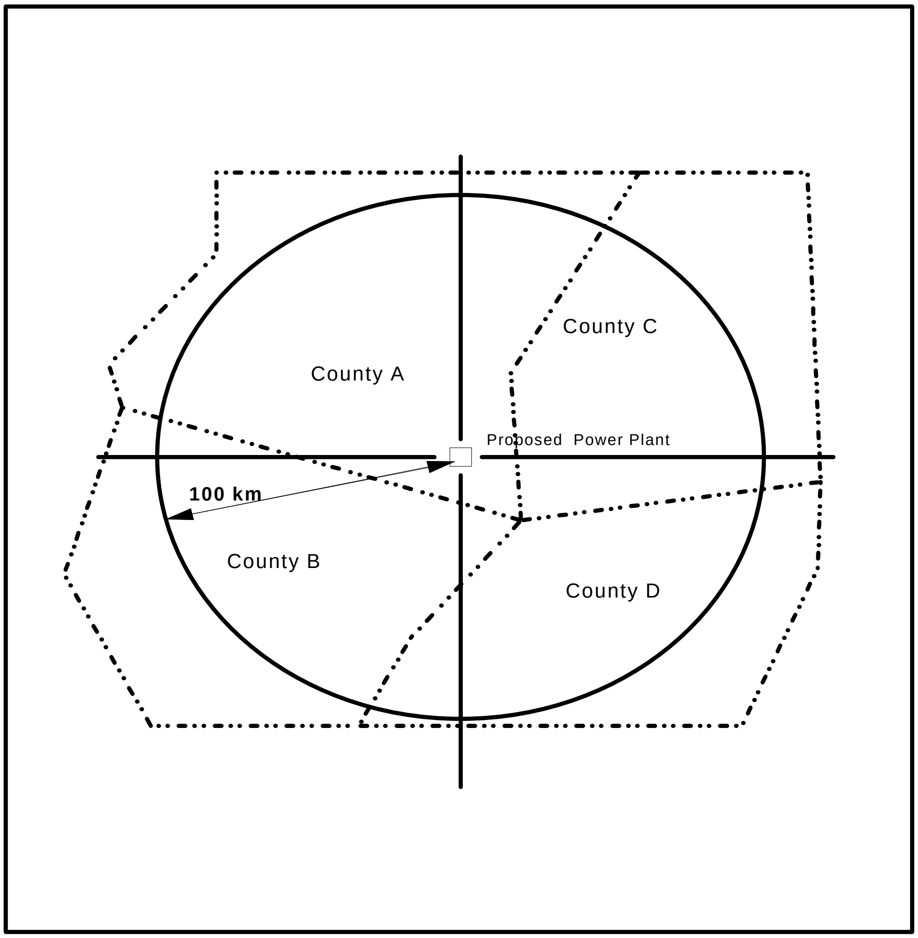

Figure I-C- 7. Counties Within 100 Kilometers of Proposed Source.

analysis must be completed in each county. With the exception of CO (for which no further analysis is required) the applicant proceeds with the full impact analysis for each affected pollutant.

V.B DEVELOPING THE EMISSIONS INVENTORIES

After the impact area has been determined, the applicant proceeds to develop the required emissions inventories. These inventories contain all of the source input data that will be used to perform the dispersion modeling for the required NAAQS and PSD increment analyses. The applicant contacts the permitting agency and requests a listing of all stationary sources within a 100-kilometer radius of the proposed new source. This takes into account the 50-kilometer impact area for SO_2 (the largest of the defined impact areas) plus the requisite 50-kilometer annular area beyond that impact area. For NO_2 and particulate matter, the applicant needs only to consider the identified sources which fall within the specific screening areas for those two pollutants.

Source input data (e.g., location, building dimensions, stack parameters, emissions factors) for the inventories are extracted from the permitting agency's air permit and emissions inventory files. Sources to consider for these inventories also include any that might have recently been issued a permit to operate, but are not yet in operation. However, in this case no such "existing" sources are identified. The following point sources are found to exist within the applicant's impact area and screening area:

- *Refinery A;*
- *Chemical Plant B;*
- *Petrochemical Complex C;*
- *Rock Crusher D;*
- *Refinery E;*
- *Gas Turbine Cogeneration Facility F; and*
- *Portland Cement Plant G.*

A diagram of the general location of these sources relative to the location proposed source is shown in *Figure C-8*. Because the Portland Cement Plant G is located 70 kilometers away from the proposed source, its impact is not considered in the NAAQS or PSD increment analyses for particulate matter. (The area of concern for particulate matter lies within 60 kilometers of the proposed source.) In this example, the applicant first develops the NAAQS emissions inventory for SO_2, particulate matter (PM-10), and NO_2.

V.B.1 THE NAAQS INVENTORY

For each criteria pollutant undergoing review, the applicant (in conjunction with the permitting agency) determines which of the identified sources will be regarded as "nearby" sources and, therefore, must be explicitly modeled. Accordingly, the applicant classifies the candidate sources in the following way:

Pollutant	Nearby sources (explicitly model)	Other Background Sources (non-modeled background)
SO_2	Refinery A Chemical Plant B Petro. Complex C Refinery E	Port. Cement Plant G
NO_2	Refinery A, Chemical Plant B Petro. Complex C Gas Turbines F	Refinery E
Particulate Matter (PM-10)	Refinery A Petro. Complex C Rock Crusher D	Chemical Plant B Refinery E Gas Turbines F

For each nearby source, the applicant now must obtain emissions input data for the model to be used. As a conservative approach, emissions input data reflecting the maximum allowable emissions rate of each nearby source could be used in the modeling analysis. However, because of the relatively

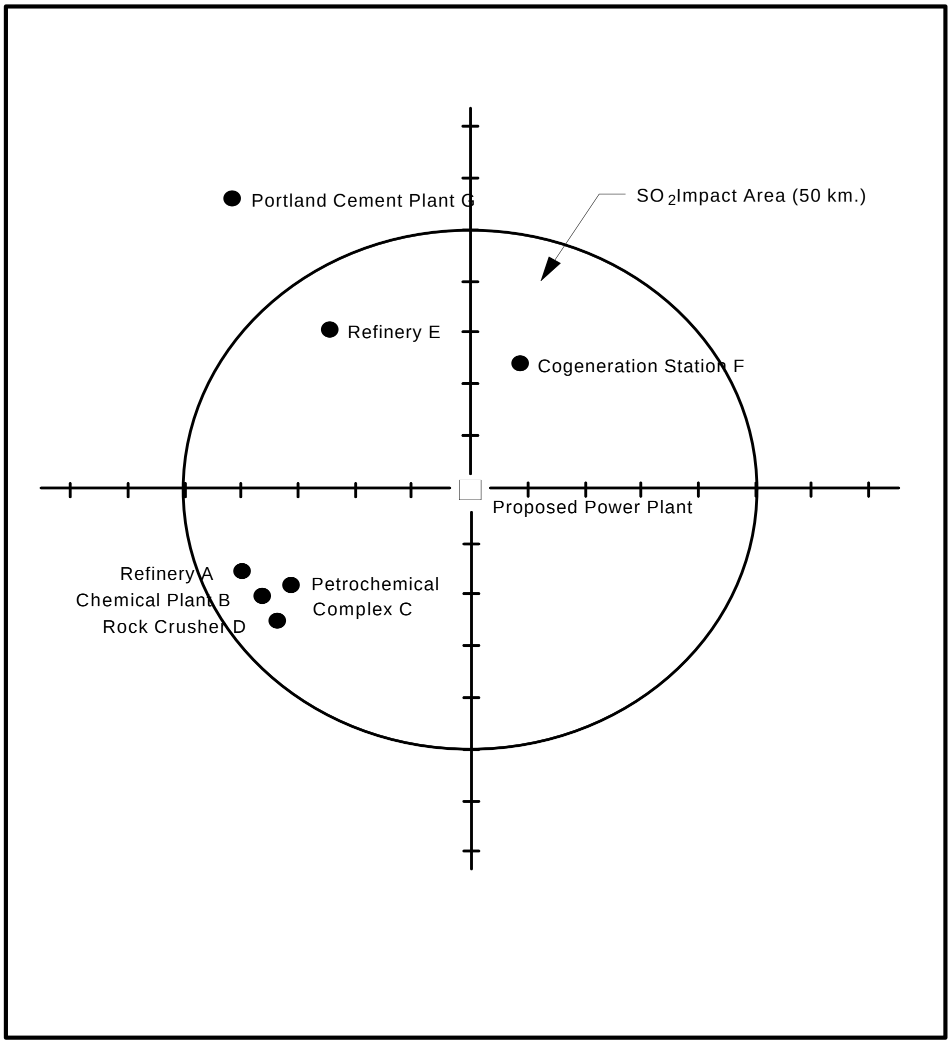

Figure C-8. Point Sources Within 100 Kilometers of Proposed Source.

high concentrations anticipated due to the clustering of sources A, B, C and D, the applicant decides to consider the actual operating factor for each of these sources for the annual averaging period, in accordance with *Table C-5*. For example, for **SO_2**, the applicant may determine the actual operating factor for sources A, B, and C, because they are classified as nearby sources for SO_2 modeling purposes. On the other hand, the applicant chooses to use the maximum allowable emissions rate for Source E in order to save the time and resources involved with determining the actual operating factors for the 45 individual **NO_2** emissions units comprising the source. If a more refined analysis is ultimately warranted, then the actual hours of operation can be obtained from Source E for the purposes of the annual averaging period.

As another example, for particulate matter (**PM-10**), the applicant may determine the actual annual operating factor for sources A, C, and D, because they are nearby sources for PM-10 modeling purposes. Again, the applicant chooses to determine the actual hours of annual operation because of the relatively high concentrations anticipated due to the clustering of these particular sources.

For each pollutant, the applicant must also determine if emissions from the sources that were <u>not</u> classified as nearby sources can be adequately represented by existing air quality data. In the case of **SO_2**, for example, data from the existing State monitoring network will adequately measure Source G's ambient impact in the impact area. However, for **PM-10**, the monitored impacts of Source B cannot be separated from the impacts of the other sources (A, C, and D) within the proximity of Source B. The applicant therefore must model this source but is allowed to determine both the actual operating factor and the actual operating level to model the source's annual impact, in accordance with *Table C-5*. For the short-term (24-hour) analysis the applicant may use the actual operating level, but <u>continuous</u> operation must be used for the operating factor. The ambient impacts of Source E and Source F will be represented by ambient monitoring data.

For the **NO_2** NAAQS inventory, the only source not classified as a nearby source is Refinery E. The applicant would have preferred to use ambient data to represent the ambient impact of this source; however, adequate ambient NO_2 data is not available for the area. In order to avoid modeling this source with a refined model for NO_2, the applicant initially agrees to use a screening technique recommended by the permitting agency to estimate the impacts of Source E.

Air quality impacts caused by building downwash must be considered because several nearby sources (A, B, C, and E) have stacks that are less than GEP stack height. In consultation with the permitting agency, the applicant is instructed to consider downwash for all four sources in the SO_2 NAAQS analysis, because the sources are all located in the SO_2 impact area. Also, after consdieration of the expected effect of downwash for other pollutants, the applicant is told that, for NO_2, only Source C must be modeled for its air quality impacts due to downwash, and no modeling for downwash needs to be done with respect to particulate matter.

The applicant gathers the necessary building dimension data for the NAAQS inventory. In this case, these data are available from the permitting agency through its permit files for sources A, B, and E. However, the applicant must contact Source C to obtain the data from that source. Fortunately, the manager of Source C readily provide the applicant this information for each of the 45 individual emission units.

V.B.2 THE INCREMENT INVENTORY

An increment inventory must be developed for **SO_2**, **particulate matter (TSP)**, and **NO_2**. This inventory includes all of the applicable emissions input data from:

- *increment-consuming sources within the impact area*; and
- *increment-consuming sources outside the impact area that affect increment consumption in the impact area.*

In considering emissions changes occurring at any of the major stationary sources identified earlier (see *Figure C-8*), the applicant must consider actual emissions changes resulting from a physical change or a change in the method of operation since the major source baseline date, and any actual emissions changes since the applicable minor source baseline date. To identify those sources (and emissions) that consume PSD increment, the applicant should request information from the permitting agency concerning the baseline area and all baseline dates (including the existence of any prior minor source baseline dates) for each applicable pollutant.

A review of previous PSD applications within the total area of concern reveals that minor source baseline dates for both SO_2 and **TSP** have already be established in Counties A and B. For NO_2, the minor source baseline date has already been established in County C. A summary of the relevant baseline dates for each pollutant in these three counties is shown in *Table C-6*. The proposed source will, however, establish the minor source baseline date in Counties C and D for SO_2 and **TSP**, and in Counties A, B and D for NO_2.

For SO_2, the increment-consuming sources deemed to contribute to increment consumption in the impact area are sources A, B, C and E. Source B underwent a major modification which established the minor source baseline date (April 21, 1984). The actual emissions increase resulting from that physical change is used in the increment analysis. Source A underwent a major modification and Source E increased its hours of operation after the minor source baseline date. The actual emissions increases resulting from both of these changes are used in the increment analysis, as well. Finally, Source C received a permit to add a new unit, but the new unit is not yet operational. Consequently, the applicant must use the potential emissions increase resulting from that new unit to model the amount of increment consumed. The existing units at Source C do not affect the increments because no actual emissions changes have occurred since the April 21, 1984 minor source baseline

TABLE C-6. EXISTING BASELINE DATES FOR SO_2, TSP, AND NO_2 FOR EXAMPLE PSD INCREMENT ANALYSIS

Pollutant	Major Source Baseline Date	Minor Source Baseline Date	Affected Counties
Sulfur dioxide	January 6, 1975	April 21, 1984	A and B
Particulate Matter (TSP)	January 6, 1975	March 14, 1985	A and B
Nitrogen Dioxide	February 8, 1988	June 8, 1988	C

date. Building dimensions data are needed in the increment inventory for nearby sources A, B, and E because each has increment-consuming emissions which are subject to downwash problems. No building dimensions data are needed for Source C, however, because only the emissions from the newly-permitted unit consume increment and the stack built for that unit was designed and constructed at GEP stack height.

For **NO_2**, only the gas turbines located at Cogeneration Station F have emissions which affect the increment. The PSD permit application for the construction of these turbines established the minor source baseline date for NO_2 (June 8, 1988). Of course, all construction-based actual emissions changes in NO_x occurring after the major source baseline date for NO_2 (February 8, 1988), at any major stationary source affect increment. However, no such emissions changes were discovered at the other existing sources in the area. Thus, only the actual emissions increase resulting from the gas turbines is included in the NO_2 increment inventory.

For **TSP**, sources A, B, C, and E are found to have units whose emissions may affect the **TSP increment** in the impact area. Source A established the minor source baseline date with a PSD permit application to modify its existing facility. Source B (which established the minor source baseline date for SO_2) experienced an insignificant increase in particulate matter emissions due to a modification prior to the minor source baseline date for particulate matter (March 14, 1985). Even though the emissions increase did not exceed the significant emissions rate for particulate matter emissions (i.e., 25 tons per year), increment is consumed by the actual increase nonetheless, because the actual emissions increase resulted from construction (i.e., a physical change or a change in the method of operation) at a major stationary source occurring after the major source baseline date for particulate matter. The applicant uses the allowable increase as a conservative estimate of the actual emissions increase. As mentioned previously, Source C received a permit to construct, but the newly-permitted unit is not yet in operation. Therefore, the applicant must use the potential emissions to model the amount of TSP increment consumed by that new unit.

Finally, Source E's actual emissions increase resulting from an increase in its hours of operation must be considered in the increment analysis. This source is located far enough outside the impact area that its effects on increment consumption in the impact area are estimated with a screening technique. Based on the conservative results, the permitting agency determines that the source's emissions increase will not affect the amount of increment consumed in the impact area.

In compiling the increment inventory, increment-consuming TSP and SO_2 emissions occurring at minor and area sources located in Counties A and B must be considered. Also, increment-consuming NO_x emissions occurring at minor, area, and mobile sources located in County C must be considered. For this example, the applicant proposes that because of the low growth in population and vehicle miles traveled in the affected counties since the applicable minor source baseline dates, emissions from area and mobile sources will not affect increment (SO_2, TSP, or NO_2) consumed within the impact area and, therefore, do not need to be included in the increment inventory. After reviewing the documentation submitted by the applicant, the permitting agency approves the applicant's proposal not to include area and mobile source emissions in the increment inventory.

V.C The Full Impact Analysis

Using the source input data contained in the emissions inventories, the next step is to model existing source impacts for both the NAAQS and PSD increment analyses. The applicant's selection of models--ISCST, for short-term modeling, and ISCLT, for long-term modeling--was made after conferring with the permitting agency and determining that the area within three kilometers of the proposed source is rural, the terrain is simple (non-complex), and there is a potential for building downwash with some of the nearby sources.

No on-site meteorological data are available. Therefore, the applicant evaluates the meteorological data collected at the National Weather Service station located at the regional airport. The applicant proposes the use of

5 years of hourly observations from 1984 to 1988 for input to the dispersion model, and the permitting agency approves their use for the modeling analyses.

The applicant, in consultation with the permitting agency, determines that terrain in the vicinity is essentially flat, so that it is not necessary to model with receptor elevations. (Consultation with the reviewing agency about receptor elevations is important since significantly different concentration estimates may be obtained between flat terrain and rolling terrain modes.)

A single-source model run for the auxiliary boiler shows that its estimated maximum ground-level concentrations of SO_2 and NO_2 will be less than the significant air quality impact levels for these two pollutants (*see Table C-4*). This boiler is modeled separately from the two main boilers because there will be a permit condition which restricts it from operating at the same time as the main boilers. For particulate matter, the auxiliary boiler's emissions are modeled together with the fugitive emissions from the proposed source to estimate maximum ground-level PM-10 concentrations. In this case, too, the resulting ambient concentrations are less than the significant ambient impact level for PM-10. Thus, operation of the auxiliary boiler would not be considered to contribute to violations of any NAAQS or PSD increment for SO_2, particulate matter, or NO_2. The auxiliary boiler is eliminated from further modeling consideration because it will not be permitted to operate when either of the main boilers is in operation.

V.C.1 NAAQS ANALYSIS

The next step is to estimate total ground-level concentrations. For the **SO_2 NAAQS** compliance demonstration, the applicant selects a coarse receptor grid of one-kilometer grid spacing to identify the area(s) of high impact caused by the combined impact form the proposed new source and nearby sources. Through the coarse grid run, the applicant finds that the area of highest estimated concentrations will occur in the southwest quadrant. In order to determine the highest total concentrations, the applicant performs a second model run for the southwest quadrant using a 100-meter receptor fine-grid.

The appropriate concentrations from the fine-grid run is added to the monitored background concentrations (including Source G's impacts) to establish the total estimated SO_2 concentrations for comparison against the NAAQS. The results show maximum SO_2 concentrations of:

- ! *600 µg/m³, 3-hour average*;
- ! *155 µg/m³, 24-hour average*; and
- ! *27 µg/m³, annual average*.

Each of the estimated total impacts is within the concentrations allowed by the NAAQS.

For the **NO_2 NAAQS** analysis, the sources identified as "nearby" for NO_2 are modeled with the proposed new source in two steps, in the same way as for the SO_2 analysis: first, using the coarse (1-kilometer) grid network and, second, using the fine (100-meter) grid network. Appropriate concentration estimates from these two modeling runs are then combined with the earlier screening results for Refinery E and the monitored background concentrations. The highest average annual concentration resulting from this approach is 85 µg/m³, which is less than the NO_2 NAAQS of 100 µg/m³, annual average.

For the **PM-10 NAAQS** analysis, the same two-step procedure (coarse and fine receptor grid networks) is used to locate the maximum estimated PM-10 concentration. Recognizing that the PM-10 NAAQS is a statistically-based standard, the applicant identifies the sixth highest 24-hour concentration (based on 5 full years of 24-hour concentration estimates) for each receptor in the network. For the annual averaging time, the applicant averages the 5 years of modeled PM-10 concentrations at each receptor to determine the 5-year average concentration at each receptor. To these long- and short-term results the applicant then added the monitored background reflecting the impacts of sources E and F, as well as surrounding area and mobile source contributions.

For the receptor network, the highest, sixth-highest 24-hour concentration is 127 µg/m³, and the highest 5-year average concentration is

38 µg/m³. These concentrations are sufficient to demonstrate compliance with the PM-10 NAAQS.

V.C.2 PSD Increment Analysis

The applicant starts the increment analysis by modeling the increment-consuming sources of **SO_2**, including the proposed new source. As a conservative first attempt, a model run is made using the maximum allowable SO_2 emissions changes resulting from each of the increment-consuming activities identified in the increment inventory. (Note that this is not the same as modeling the allowable emissions rate for each <u>entire</u> source.) Using a coarse (1-kilometer) receptor grid, the area downwind of the source conglomeration in the southwest quadrant was identified as the area where the maximum concentration increases have occurred. The modeling is repeated for the southwest quadrant using a fine (100-meter) receptor grid network.

The results of the fine-grid model run show that, in the case of peak concentrations downwind of the southwest source conglomeration, the allowable SO_2 increment will be violated at several receptors during the 24-hour averaging period. The violations include significant ambient impacts from the proposed power plant. Further examination reveals that Source A in the southwest quadrant is the large contributor to the receptors where the increment violations are predicted. The applicant therefore decides to refine the analysis by using actual emissions increases rather than allowable emissions increases where needed.

It is learned, and the permitting agency verifies, that the increment-consuming boiler at Source A has burned refinery gas rather than residual oil since start-up. Consequently, the actual emissions increase at Source A's

boiler, based upon the use of refinery gas during the preceding 2 years, is substantially less than the allowable emissions increase assumed from the use of residual oil. Thus, the applicant models the actual emissions increase at Source A and the allowable emissions increase for the other modeled sources.

This time the modeling is repeated only for the critical time periods and receptors.

The maximum predicted SO_2 concentration increases over the baseline concentration are as follows:

- *302 µg/m^3, 3-hour average*;
- *72 µg/m^3, 24-hour average*; and
- *12 µg/m^3, annual average*.

The revised modeling demonstrates compliance with the SO_2 increments. Hence, no further SO_2 modeling is required for the increment analysis.

The full impact analysis for the **NO_2 increment** is performed by modeling Source F--the sole existing NO_2 increment-consuming source--and the proposed new source. The modeled estimates yield a maximum concentration increase of 21 µg/m^3, annual average. This increase will not exceed the maximum allowable increase of 25 µg/m^3 for NO_2.

With the SO_2 and NO_2 increment portions of the analysis complete, the only remaining part is for the **particulate matter (TSP) increments**. The applicant must consider the effects of the four existing increment-consuming sources (A, B, C, and E) in addition to ambient TSP concentrations caused by the proposed source (including the fugitive emissions). The total increase in TSP concentrations resulting from all of these sources is as follows:

- 28 µg/m^3, 24-hour average; and
- 13 µg/m^3, annual average.

The results demonstrate that the proposed source will not cause any violations of the TSP increments.

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VII. INDEX

CHAPTER D

ADDITIONAL IMPACTS ANALYSIS

I. INTRODUCTION

All ***PSD*** permit applicants must prepare an additional impacts analysis for each pollutant subject to regulation under the Act. This analysis assesses the impacts of air, ground and water pollution on soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant from the source or modification under review, and from associated growth.

Other impact analysis requirements may also be imposed on a permit applicant under local, State or Federal laws which are outside the PSD permitting process. Receipt of a PSD permit does not relieve an applicant from the responsibility to comply fully with such requirements. For example, two Federal laws which may apply on occasion are the ***Endangered Species Act*** and the ***National Historic Preservation Act***. These regulations may require additional analyses (although not as part of the PSD permit) if any federally-listed rare or endangered species, or any site that is included (or is eligible to be included) in the National Register of Historic Sites, are identified in the source's impact area.

Although each applicant for a ***PSD*** permit must perform an additional impacts analysis, the depth of the analysis generally will depend on existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the source's impact area. It is important that the analysis fully document all sources of information, underlying assumptions, and any agreements made as a part of the analysis.

Generally, small emissions increases in most areas will not have adverse impacts on soils, vegetation, or visibility. However, an additional impacts analysis still must be performed. Projected emissions from both the new source or modification and emissions from associated residential, commercial, or industrial growth are combined and modeled for the impacts assessment analysis. While this section offers applicants a general approach to an additional impacts analysis, the analysis does not lend itself to a "cookbook" approach.

II. ELEMENTS OF THE ADDITIONAL IMPACTS ANALYSIS

The additional impacts analysis generally has three parts, as follows:

(1) growth;

(2) soil and vegetation impacts; and

(3) visibility impairment.

II.A. GROWTH ANALYSIS

The elements of the growth analysis include:

(1) a projection of the associated[5] industrial, commercial, and residential source growth that will occur in the area due to the source; and

(2) an estimate of the air emissions generated by the above associated industrial, commercial, and residential growth.

First, the applicant needs to assess the availability of residential, commercial, and industrial services existing in the area. The next step is to predict how much new growth is likely to occur to support the source or modification under review. The amount of residential growth will depend on the size of the available work force, the number of new employees, and the availability of housing in the area. Industrial growth is growth in those industries providing goods and services, maintenance facilities,and other large industries necessary for the operation of the source or modification under review. Excluded from consideration as associated sources are mobile sources and temporary sources.

Having completed this portrait of expected growth, the applicant then begins developing an estimate of the secondary air pollutant emissions which would likely result from this permanent residential, commercial, and

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[5] Associated growth is growth that comes about as the result of the construction or modification of a source, but is not a part of that source. It does not include the growth projections addressed by 40 CFR 51.166(n)(3)(ii) and 40 CFR 52.21(n)(2)(ii), which have been called non-associated growth. Emissions attributable to associated growth are classified as secondary emissions.

industrial growth. The applicant should generate emissions estimates by consulting such sources as manufacturers specifications and guidelines, ***AP-42***, other ***PSD*** applications, and comparisons with existing sources.

The applicant next combines the secondary air pollutant emissions estimates for the associated growth with the estimates of emissions that are expected to be produced directly by the proposed source or modification. The combined estimate serves as the input to the air quality modeling analysis, and the result is a prediction of the ground-level concentration of pollutants generated by the source and any associated growth.

II.B. AMBIENT AIR QUALITY ANALYSIS

The ambient air quality analysis projects the air quality which will exist in the area of the proposed source or modification during construction and after it begins operation. The applicant first combines the air pollutant emissions estimates for the associated growth with the estimates of emissions from the proposed source or modification. Next, the projected emissions from other sources in the area which have been permitted (but are not yet in operation) are included as inputs to the modeling analysis. The applicant then models the combined emissions estimate and adds the modeling analysis results to the background air quality to arrive at an estimate of the total ground-level concentrations of pollutants which can be anticipated as a result of the construction and operation of the proposed source.

II.C. SOILS AND VEGETATION ANALYSIS

The analysis of soil and vegetation air pollution impacts should be based on an inventory of the soil and vegetation types found in the impact area. This inventory should include all vegetation with any commercial or recreational value, and may be available from conservation groups, State agencies, and universities.

For most types of soil and vegetation, ambient concentrations of criteria pollutants below the secondary national ambient air quality standards

(NAAQS) will not result in harmful effects. However, there are sensitive vegetation species (e.g., soybeans and alfalfa) which may be harmed by long-term exposure to low ambient air concentrations of regulated pollutants for which are no NAAQS. For example, exposure of sensitive plant species to 0.5 micrograms per cubic meter of fluorides (a regulated, non-criteria pollutant) for 30 days has resulted in significant foliar necrosis.

Good references for applicants and reviewers alike include the ***EPA Air Quality Criteria Documents***, a U.S. Department of the Interior document entitled ***Impacts of Coal-Fired Plants on Fish, Wildlife, and Their Habitats***, and the U.S. Forest Service document, ***A Screening Procedure to Evaluate Air Pollution Effects on Class I Wilderness Areas***. Another source of reference material is the National Park Service report, ***Air Quality in the National Parks***, which lists numerous studies on the biological effects of air pollution on vegetation.

II.D. VISIBILITY IMPAIRMENT ANALYSIS

In the visibility impairment analysis, the applicant is especially concerned with impacts that occur within the area affected by applicable emissions. Note that the visibility analysis required here is distinct from the Class I area visibility analysis requirement. The suggested components of a good visibility impairment analysis are:

! a determination of the visual quality of the area,

! an initial screening of emission sources to assess the possibility of visibility impairment, and

! if warranted, a more in-depth analysis involving computer models.

To successfully complete a visibility impairments analysis, the applicant is referred to an EPA document entitled ***Workbook for Estimating Visibility Impairment*** or its projected replacement, the ***Workbook for Plume Visual Impact Screening and Analysis***. In this workbook, EPA outlines a screening procedure designed to expedite the analysis of emissions impacts on the visual quality of an area. The workbook was designed for Class I area impacts, but the outlined procedures are generally applicable to other areas as well. The following sections are a brief synopsis of the screening procedures.

II.D.1. SCREENING PROCEDURES: LEVEL 1

The Level 1 visibility screening analysis is a series of conservative calculations designed to identify those emission sources that have little potential of adversely affecting visibility. The VISCREEN model is recommended for this first level screen. Calculated values relating source emissions to visibility impacts are compared to a standardized screening value. Those sources with calculated values greater than the screening criteria are judged to have potential visibility impairments. If potential visibility impairments are indicated, then the Level 2 analysis is undertaken.

II.D.2. SCREENING PROCEDURES: LEVEL 2

The Level 2 screening procedure is similar to the Level 1 analysis in that its purpose is to estimate impacts during worst-case meteorological conditions; however, more specific information regarding the source, topography, regional visual range, and meteorological conditions is assumed to be available. The analysis may be performed with the aid of either hand calculations, reference tables, and figures, or a computer-based visibility model called "***PLUVUE II***."

II.D.3. SCREENING PROCEDURES: LEVEL 3

If the Levels 1 and 2 screening analyses indicated the possibility of visibility impairment, a still more detailed analysis is undertaken in Level 3 with the aid of the plume visibility model and meteorological and other regional data. The purpose of the Level 3 analysis is to provide an accurate description of the magnitude and frequency of occurrence of impact.

The procedures for utilizing the plume visibility model are described in the document ***User's Manual for the Plume Visibility Model***, which is available from EPA.

II.E. CONCLUSIONS

The ***additional impacts analysis*** consists of a ***growth analysis***, a ***soil and vegetation analysis***, and a ***visibility impairment analysis***. After carefully examining all data on additional impacts, the reviewer must decide whether the analyses performed by a particular applicant are satisfactory. General criteria for determining the completeness and adequacy of the analyses may include the following:

- whether the applicant has presented a clear and accurate portrait of the soils, vegetation, and visibility in the proposed impacted area;
- whether the applicant has provided adequate documentation of the potential emissions impacts on soils, vegetation, and visibility; and
- whether the data and conclusions are presented in a logical manner understandable by the affected community and interested public.

III. ADDITIONAL IMPACTS ANALYSIS EXAMPLE

Sections D.1 and D.2 outlined, in general terms, the elements and considerations found in a successful additional impacts analysis. To demonstrate how this analytic process would be applied to a specific situation, a hypothetical case has been developed for a mine mouth power plant. This section will summarize how an additional impacts analysis would be performed on that facility.

III.A. EXAMPLE BACKGROUND INFORMATION

The mine mouth power plant consists of a power plant and an adjoining lignite mine, which serves as the plant's source of fuel. The plant is capable of generating 1,200 megawatts of power, which is expected to supply a utility grid (little is projected to be consumed locally). This project is located in a sparsely populated agricultural area in the southwestern United States. The population center closest to the plant is the town of Clarksville, population 2,500, which is located 20 kilometers from the plant site. The next significantly larger town is Milton, which is 130 kilometers away and has a population of 20,000. The nearest Class I area is more than 200 kilometers away from the proposed construction. The applicant has determined that within the area under consideration there are no National or State forests, no areas which can be described as scenic vistas, and no points of special historical interest.

The applicant has estimated that construction of the power plant and development of the mine would require an average work force of 450 people over a period of 36 months. After all construction is completed, about 150 workers will be needed to operate the facilities.

III.B. GROWTH ANALYSIS

To perform a growth analysis of this project, the applicant began by projecting the growth associated with the operation of the project.

III.B.1. WORK FORCE

The applicant consulted the State employment office, local contractors, trade union officers, and other sources for information on labor capability and availability, and made the following determinations.

Most of the 450 construction jobs available will be filled by workers commuting to the site, some from as far away as Milton. Some workers and their families will move to Clarksville for the duration of the construction. Of the permanent jobs associated with the project, about 100 will be filled by local workers. The remaining 50 permanent positions will be filled by nonlocal employees, most of whom are expected to relocate to the vicinity of Clarksville.

III.B.2. HOUSING

Contacts with local government housing authorities and realtors, and a survey of the classified advertisements in the local newspaper indicated that the predominant housing unit in the area is the single family house or mobile home, and the easy availability of mobile homes and lots provides a local capacity for quick expansion. Although there will be some emissions associated with the construction of new homes, these emissions will be temporary and, because of the limited numbers of new homes expected, are considered to be insignificant.

III.B.3. INDUSTRY

Although new industrial jobs often lead to new support jobs as well (i.e., grocers, merchants, cleaners, etc.), the small number of new people brought into the community through employment at the plant is not expected to generate commercial growth. For example, the proposed source will not require an increase in small support industries (i.e., small foundries or rock crushing operations).

As a result of the relatively self-contained nature of mine mouth plant operations, no related industrial growth is expected to accompany the operation of the plant. Emergency and full maintenance capacity is contained within the power-generating station. With no associated commercial or industrial growth projected, it then follows that there will be no growth-related air pollution impacts.

III.C. SOILS AND VEGETATION

In preparing a soils and vegetation analysis, the applicant acquired a list of the soil and vegetation types indigenous to the impact area. The vegetation is dominated by pine and hardwood trees consisting of loblolly pine, blackjack oak, southern red oak, and sweet gum. Smaller vegetation consists of sweetbay and holly. Small farms are found west of the forested area. The principal commercial crops grown in the area are soybeans, corn, okra, and peas. The soils range in texture from loamy sands to sandy clays. The principal soil is sandy loam consisting of 50 percent sand, 15 percent silt, and 35 percent clay.

The applicant, through a literature search and contacts with the local universities and experts on local soil and vegetation, determined the sensitivity of the various soils and vegetation types to each of the applicable pollutants that will be emitted by the facility in significant amounts. The applicant then correlated this information with the estimates of pollutant concentrations calculated previously in the air quality modeling analysis.

After comparing the predicted ambient air concentrations with soils and vegetation in the impact area, only soybeans proved to be potentially sensitive. A more careful examination of soybeans revealed that no adverse effects were expected at the low concentrations of pollutants predicted by the modeling analysis. The predicted sulfur dioxide (SO_2) ambient air concentration is lower than the level at which major SO_2 impacts on soybeans have been demonstrated (greater than 0.1 ppm for a 24-hour period).

Fugitive emissions emitted from the mine and from coal pile storage will be deposited on both the soil and leaves of vegetation in the immediate area of the plant and mine. Minor leaf necrosis and lower photosynthetic activity is expected, and over a period of time the vegetation's community structure may change. However, this impact occurs only in an extremely limited, nonagricultural area very near the emissions site and therefore is not considered to be significant.

The potential impact of limestone preparation and storage also must be considered. High relative humidity may produce a crusting effect of the fugitive limestone emissions on nearby vegetation. However, because of BACT on limestone storage piles, this impact is slight and only occurs very near the power plant site. Thus, this impact is judged insignificant.

III.D. VISIBILITY ANALYSIS

Next, the applicant performed a visibility analysis, beginning with a screening procedure similar to that outlined in the EPA document ***Workbook for Estimating Visibility Impairment***. The screening procedure is divided into three levels. Each level represents a screening technique for an increasing possibility of visibility impairment. The applicant executed a Level 1 analysis involving a series of conservative tests that permitted the analyst to eliminate sources having little potential for adverse or significant visibility impairment. The applicant performed these calculations for various distances from the power plant. In all cases, the results of the calculations were numerically below the standardized screening criteria. In preparing the suggested visual and aesthetic description of the area under review, the applicant noted the absence of scenic vistas. Therefore, the applicant concluded that no visibility impairment was expected to occur within the source impact area and that the Level 2 and Level 3 analyses were unnecessary.

III.E. EXAMPLE CONCLUSIONS

The applicant completed the additional impacts analysis by documenting every element of the analysis and preparing the report in straightforward, concise language. This step is important, because a primary intention of the PSD permit process is to generate public information regarding the potential impacts of pollutants emitted by proposed new sources or modifications on their impact areas.

NOTE: This example provides only the highlights of an additional impacts analysis for a hypothetical mine mouth power plant. An actual analysis would contain much more detail, and other types of facilities might produce more growth and more, or different, kinds of impacts. For example, the construction of a large manufacturing plant could easily generate air quality-related growth impacts, such as a large influx of workers into an area and the growth of associated industries. In addition, the existence of particularly sensitive forms of vegetation, the presence of Class I areas, and the existence of particular meteorological conditions would require an analysis of much greater scope.

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CHAPTER E

CLASS I AREA IMPACT ANALYSIS

I. INTRODUCTION

Class I areas are areas of special national or regional natural, scenic, recreational, or historic value for which the PSD regulations provide special protection. This section identifies Class I areas, describes the protection afforded them under the Clean Air Act (CAA), and discusses the procedures involved in preparing and reviewing a permit application for a proposed source with potential Class I area air quality impacts.

II. CLASS I AREAS AND THEIR PROTECTION

Under the CAA, three kinds of Class I areas either have been, or may be, designated. These are:

- ***mandatory Federal Class I areas;***
- ***Federal Class I areas;*** and
- ***non-Federal Class I areas.***

Mandatory Federal Class I areas are those specified as Class I by the CAA on August 7, 1977, and include the following areas in existence on that date:

- international parks;
- national wilderness areas (including certain national wildlife refuges, national monuments and national seashores) which exceed 5,000 acres in size;
- national memorial parks which exceed 5,000 acres in size; and
- national parks which exceed 6,000 acres in size.

Mandatory Federal Class I areas, which may not be reclassified, are listed by State in Table E-1. They are managed either by the Forest Service (FS), National Park Service (NPS), or Fish and Wildlife Service (FWS).

The States and Indian governing bodies have the authority to designate additional Class I areas. These Class I areas are not "mandatory" and may be reclassified if the State or Indian governing body chooses. States may reclassify either State or Federal lands as Class I, while Indian governing bodies may reclassify only lands within the exterior boundaries of their respective reservations.

TABLE E-1. MANDATORY CLASS I AREAS

State/Type/Area	Managing Agency
Alabama	
National Wilderness Areas	
Sipsey	FS
Alaska	
National Parks	
Denali	NPS
National Wilderness Areas	
Bering Sea	FWS
Simeonof	FWS
Tuxedni	FWS
Arizona	
National Parks	
Grand Canyon	NPS
Petrified Forest	NPS
National Wilderness Areas	
Chiricahua Nat. Monu.	NPS
Chiricahua	FS
Galiuro	FS
Mazatzal	FS
Mt. Baldy	FS
Pine Mountain	FS
Saguaro Nat. Monu.	NPS
Sierra Ancha	FS
Superstition	FS
Sycamore Canyon	FS
Arkansas	
National Wilderness Areas	
Caney Creek	FS
Upper Buffalo	FS
California	
National Parks	
Kings Canyon	NPS
Lassen Volcanic	NPS
Redwood	NPS
Sequoia	NPS
Yosemite	NPS
California - Continued	
National Wilderness Areas	
Agua Tibia	FS
Caribou	FS
Cucamonga	FS
Desolation	FS
Dome Land	FS
Emigrant	FS
Hoover	FS
John Muir	FS
Joshua Tree	NPS
Kaiser	FS
Lava Beds	NPS
Marble Mountain	FS
Minarets	FS
Mokelumne	FS
Pinnacles	NPS
Point Reyes	NPS
San Gabriel	FS
San Gorgonio	FS
San Jacinto	FS
San Rafael	FS
South Warner	FS
Thousand Lakes	FS
Ventana	FS
Yolla Bolly-Middle-Eel	FS
Colorado	
National Parks	
Mesa Verde	NPS
Rocky Mountain	NPS
National Wilderness Areas	
Black Canyon of the Gunn.	NPS
Eagles Nest	FS
Flat Tops	FS
Great Sand Dunes	NPS
La Garita	FS
Maroon Bells Snowmass	FS
Mount Zirkel	FS
Rawah	FS
Weminuche	FS
West Elk	FS

TABLE E-1. Continued

State/Type/Area	Managing Agency
Florida	
National Parks	
Everglades	NPS
National Wilderness Areas	
Bradwell Bay	FS
Chassahowitzka	FWS
Saint Marks	FWS
Georgia	
National Wilderness Areas	
Cohutta	FS
Okefenokee	FWS
Wolf Island	FWS
Hawaii	
National Parks	
Haleakala	NPS
Hawaii Volcanoes	NPS
Idaho	
National Parks	
Yellowstone (See Wyoming)	
National Wilderness Areas	
Craters of the Moon	NPS
Hells Canyon (see Oregon)	
Sawtooth	FS
Selway-Bitterroot	FS
Kentucky	
National Parks	
Mammoth Cave	NPS
Louisiana	
National Wilderness Areas	
Breton	FWS
Maine	
National Parks	
Acadia	NPS
National Wilderness Areas	
Moosehorn	FWS
Michigan	
National Parks	
Isle Royale	NPS
National Wilderness Areas	
Seney	FWS
Minnesota	
National Parks	
Voyageurs	NPS
National Wilderness Areas	
Boundary Waters Canoe Ar.	FS
Missouri	
National Wilderness Areas	
Hercules-Glades	FS
Mingo	FWS
Montana	
National Parks	
Glacier	NPS
Yellowstone (See Wyoming)	
National Wilderness Areas	
Anaconda-Pintlar	FS
Bob Marshall	FS
Cabinet Mountains	FS
Gates of the Mountain	FS
Medicine Lake	FWS
Mission Mountain	FS
Red Rock Lakes	FWS
Scapegoat	FS
Selway-Bitterroot (see Idaho)	
U.L. Bend	FWS
Nevada	
National Wilderness Areas	
Jarbridge	FS
New Hampshire	
National Wilderness Areas	
Great Gulf	FS
Presidential Range-Dry R.	FS

TABLE E-1. Continued

State/Type/Area	Managing Agency
New Jersey	
National Wilderness Areas	
Brigantine	FWS
New Mexico	
National Parks	
Carlsbad Caverns	NPS
National Wilderness Areas	
Bandelier	NPS
Bosque del Apache	FWS
Gila	FS
Pecos	FS
Salt Creek	FWS
San Pedro Parks	FS
Wheeler Peak	FS
White Mountain	FS
North Carolina	
National Parks	
Great Smoky Mountains (see Tennessee)	
National Wilderness Areas	
Joyce Kilmer-Slickrock	FS
Linville Gorge	FS
Shining Rock	FS
Swanquarter	FWS
North Dakota	
National Parks	
Theodore Roosevelt	NPS
National Wilderness Areas	
Lostwood	FWS
Oklahoma	
National Wilderness Areas	
Wichita Mountains	FWS
Oregon	
National Parks	
Crater Lake	NPS
Oregon - Continued	
National Wilderness Areas	
Diamond Peak	FS
Eagle Cap	FS
Gearhart Mountain	FS
Hells Canyon	FS
Kalmiopsis	FS
Mountain Lakes	FS
Mount Hood	FS
Mount Jefferson	FS
Mount Washington	FS
Strawberry Mountain	FS
Three Sisters	FS
South Carolina	
National Wilderness Areas	
Cape Romain	FWS
South Dakota	
National Parks	
Wind Cave	NPS
National Wilderness Areas	
Badlands	NPS
Tennessee	
National Parks	
Great Smoky Mountains	NPS
National Wilderness Areas	
Joyce Kilmer-Slickrock (see North Carolina)	
Texas	
National Parks	
Big Bend	NPS
Guadalupe Mountain	NPS

TABLE E-1.* Continued

State/Type/Area	Managing Agency
Utah	
National Parks	
Arches	NPS
Bryce Canyon	NPS
Canyonlands	NPS
Capitol Reef	NPS
Vermont	
National Wilderness Areas	
Lye Brook	FS
Virgin Islands	
National Parks	
Virgin Islands	NPS
Virginia	
National Parks	
Shenandoah	NPS
National Wilderness Areas	
James River Face	FS
Washington	
National Parks	
Mount Rainier	NPS
North Cascades	NPS
Olypmic	NPS
National Wilderness Areas	
Alpine Lakes	FS
Glacier Peak	FS
Goat Rocks	FS
Mount Adams	FS
Pasayten	FS
West Virginia	
National Wilderness Areas	
Dolly Sods	FS
Otter Creek	FS
Wisconsin	
National Wilderness Area	
Rainbow Lake	FWS
Wyoming	
National Parks	
Grand Teton	NPS
Yellowstone	NPS
National Wilderness Areas	
Bridger	FS
Fitzpatrick	FS
North Absaroka	FS
Teton	FS
Washakie	FS
International Parks	
Roosevelt-Campobello	n/a

Any Federal lands a State so reclassifies are considered *Federal Class I areas*. In so far as these areas are not mandatory Federal Class II areas, these areas may be again reclassified at some later date. (there are as of the date of this manual, no State-designated Federal Class I areas.) However, in accordance with the CAA the following areas may be redesignated only as Class I or II.

> an area which as of August 7, 1977, exceeded 10,000 acres in size and was a national monument, a national primitive area, a national preserve, a national recreation area, a national wild and scenic river, a national wildlife refuge, a national lakeshore or seashore; and
>
> a national park or national wilderness area established after August 7, 1977, which exceeds 10,000 acres in size.

Federal Class I areas are managed by the Forest Service (FS), the National Park Service (NPS), or the Fish and Wildlife Service (FWS).

State or Indian lands reclassified as Class I are considered non-Federal Class I areas. Four Indian Reservations which are non-Federal Class I areas are the Northern Cheyenne, Fort Peck, and Flathead Indian Reservations in Montana, and the Spokane Indian Reservation in Washington.

One way in which air quality degradation is limited in all Class I areas is by stringent limits defined by the Class I increments for sulfur dioxides, particulate matter [measured as total suspended particulate (TSP)], and nitrogen dioxide. As explained previously in Chapter C, Section II.A, PSD increments are the maximum increases in ambient pollutant concentrations allowed over the baseline concentrations. In addition, the FLM of each Class I area is charged with the affirmative responsibility to protect that area's unique attributes, expressed generically as air quality related values (AQRV's). The FLM, including the State or Indian governing body, where applicable, is responsible for defining specific AQRV's for an area and for establishing the criteria to determine an adverse impact on the AQRV's.

Congress intended the Class I increments to serve a special function in protecting the air quality and other unique attributes in Class I areas. In Class I areas, increments are a means of determining which party, i.e., the permit applicant or the FLM, has the burden of proof for demonstrating whether the proposed source would not cause or contribute to a Class I increment violation, the FLM may demonstrate to EPA, or the appropriate permitting authority, that the emissions from a proposed source would have an adverse impact on any AQRV's established for a particular Class I area.

If, on the other hand, the proposed source would cause or contribute to a Class I increment violation, the burden of proof is on the applicant to demonstrate to the FLM that the emissions from the source would have no adverse impact on the AQRV's. These concepts are further described in Section III.d of this chapter.

II.A. CLASS I INCREMENTS

The Class I increments for total suspended particulate matter (TSP), SO_2, and NO_2 are listed in Table E-2. Increments are the maximum increases in ambient pollutant concentrations allowed over baseline concentrations. Thus, these increments should limit increases in ambient pollutant concentrations caused by new major sources or major modifications near Class I areas. Increment consumption analyses for Class I areas should include not only emissions from the proposed source, but also include increment-consuming emissions from other sources.

TABLE E-2. CLASS I INCREMENTS (ug/m^3)

Pollutant	Annual	24-hour	3-hour
Sulfur dioxide	2	5	25
Particulate matter (TSP)	5	10	N/A
Nitrogen dioxide	2.5	N/A	N/A

II.B. AIR QUALITY-RELATED VALUES (AQRV's)

The AQRV's are those attributes of a Class I area that deterioration of air quality may adversely affect. For example, the Forest Service defines AQRV's as "features or properties of a Class I area that made it worthy of designation as a wilderness and that could be adversely affected by air pollution." Table E-3 presents an extensive (though not exhaustive) list of example AQRV's and the parameters that may be used to detect air pollution-caused changes in them. Adverse impacts on AQRV's in Class I areas may occur even if pollutant concentrations do not exceed the Class I increments.

Air quality-related values generally are expressed in broad terms. The impacts of increased pollutant levels on some AQRV's are assessed by measuring specific parameters that reflect the AQRV's status. For instance, the projected impact on the presence and vitality of certain species of animals or plants may indicate the impact of pollutants on AQRV's associated with species diversity or with the preservation of certain endangered species. Similarly, an AQRV associated with water quality may be measured by the pH of a water body or by the level of certain nutrients in the water. The AQRV's of various Class I areas differ, depending on the purpose and characteristics of a particular area and on assessments by the area's FLM. Also, the concentration at which a pollutant adversely impacts an AQRV can vary between Class I areas because the sensitivity of the same AQRV often varies between areas.

When a proposed major source's or major modification's modeled emissions may affect a Class I area, the applicant analyzes the source's anticipated impact on visibility and provides the information needed to determine its effect on the area's other AQRV's. The FLM's have established criteria for determining what constitutes an "adverse" impact. For example, the NPS

TABLE E-3. EXAMPLES OF AIR QUALITY-RELATED VALUES AND POTENTIAL AIR POLLUTION-CAUSED CHANGES

Air Quality Related Value	Potential Air Pollution-Caused Changes
Flora and Fauna	Growth, Mortality, Reproduction, Diversity, Visible Injury, Succession, Productivity, Abundance
Water	Total Alkalinity, Metals Concentration, Anion and Cation Concentration, pH, Dissolved Oxygen
Visibility	Contrast, Visual Range, Coloration
Cultural-Archeological and Paleontological	Decomposition Rate
Odor	Odor

defines an "adverse impact" as "any impact that: (1) diminishes the area's national significance; (2) impairs the structure or functioning of ecosystems; or (3) impairs the quality of the visitor experience." If an FLM determines, based on any information available, that a source will adversely impact AQRV's in a Class I area, the FLM may recommend that the reviewing agency deny issuance of the permit, even in cases where no applicable increments would be exceeded.

II.C. FEDERAL LAND MANAGER

The FLM of a Class I area has an affirmative responsibility to protect AQRV's for that area which may be adversely affected by cumulative ambient pollutant concentrations. The FLM is responsible for evaluating a source's projected impact on the AQRV's and recommending that the reviewing agency either approve or disapprove the source's permit application based on anticipated impacts. The FLM also may suggest changes or conditions on a permit. However, the reviewing agency makes the final decisions on permit issuance. The FLM also advises reviewing agencies and permit applicants about other FLM concerns, identifies AQRV's and assessment parameters for permit applicants, and makes ambient monitoring recommendations.

The U.S. Departments of Interior (USDI) and Agriculture (USDA) are the FLM's responsible for protecting and enhancing AQRV's in Federal Class I areas. Those areas in which the USDI has authority are managed by the NPS and the FWS, while the USDA Forest Service separately reviews impacts on Federal Class I national wildernesses under its jurisdiction. The PSD regulations specify that the reviewing authority furnish written notice of any permit application for a proposed major stationary source or major modification, the emissions from which may affect a Class I area, to the FLM and the official charged with direct responsibility for management of any lands within the area. Although the Secretaries of Interior and Agriculture are the FLM's for Federal Class I areas, they have delegated permit review to specific elements within each department. In the USDI, the NPS Air Quality Division reviews PSD permits for both the NPS and FWS. Hence, for sources that may affect wildlife refuges, applicants and reviewing agencies should contact and send correspondence to both the NPS and the wildlife refuge manager located at the refuge. Table E-4 summarizes the types of Federal Class I areas managed by each FLM. In the USDA, the Forest Service has delegated to its regional offices (listed in Table E-5) the responsibility for PSD permit application review.

TABLE E-4. FEDERAL LAND MANAGERS

Federal Land Manager	Federal Class I Areas Managed	Address
National Park Service (USDI)	National Memorial Parks National Monuments[1] National Parks National Seashores[1]	Air Quality Division National Park Service - Air P.O. Box 25287 Denver, CO 80225-0287
Fish and Wildlife Service (USDI)	National Wildlife Refuges[1]	Send to NPS, above, and to Wildlife Refuge Manager.[2]
Forest Service (USDA)	National Wildernesses	Send to Forest Service Regional Office (See Table E-5)

[1]Only those national monuments, seashores, and wildlife refuges which also were designated wilderness areas as of August 7, 1977 are included as mandatory Federal Class I areas.

[2]The Wildlife Refuge Manager is located at or near each refuge.

TABLE E-5. USDA FOREST SERVICE REGIONAL OFFICES AND STATES THEY SERVE*

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USDA Forest Service Northern Region Federal Building P.O. Box 7669 Missoula, MT 59807 [ID, ND, SD, MT]	USDA Forest Service Rocky Mountain Region 11177 West 8th Avenue P.O. Box 25127 Lakewood, CO 80225 [CO, KS, NE, SD, WY]
USDA Forest Service Southwestern Region Federal Building 517 Gold Avenue, SW Albuquerque, NM 87102 [AZ, NM]	USDA Forest Service Intermountain Region Federal Building 324 25th Street Ogden, UT 84401 [ID, UT, NV, WY]
USDA Forest Service Pacific Southwest Region 630 Sansome Street San Francisco, CA 94111 [CA, HI, GUAM, Trust Terr. of Pacific]	USDA Forest Service Pacific Northwest Region P.O. Box 3623 Portland, OR 97208 [WA, OR]
USDA Forest Service Southern Region 1720 Peachtree Road, NW Atlanta, GA 30367 [AL, AR, FL, GA, KY, LA, MS, NC, OK, PR, SC, TN, TX, VI, VA]	USDA Forest Service Eastern Region 310 W. Wisconsin Avenue, Room 500 Milwaukee, WI 53203 [CT, DE, IL, IN, IA, ME, MD, MA, MI, MN, MO, NH, NY, NJ, OH, PA, RI, VT, WV, WI]
USDA Forest Service Alaska Region P.O. Box 21628 Juneau, AK 99802-1628 [AK]	

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* Some Regions serve only part of a State.

III. CLASS I AREA IMPACT ANALYSIS AND REVIEW

This section presents the procedures an applicant should follow in preparing an analysis of a proposed source's impact on air quality and AQRV's in Class I areas, including recommended informal steps. For each participant in the analysis - the permit applicant, the FLM, and the permit reviewing agency - the section summarizes their role and responsibilities.

III.A. SOURCE APPLICABILITY

If a proposed major source or major modification ***may affect*** a Class I area, the Federal PSD regulations require the reviewing authority to provide written notification of any such proposed source to the FLM (and the USDI and USDA officials delegated permit review responsibility). The meaning of the term "may affect" is interpreted by EPA policy to include all major sources or major modifications which propose to locate within 100 kilometers (km) of a Class I area. Also, if a major source proposing to locate at a distance greater than 100 km is of such size that the reviewing agency or FLM is concerned about potential emission impacts on a Class I area, the reviewing agency can ask the applicant to perform an analysis of the source's potential emissions impacts on the Class I area. This is because certain meteorological conditions, or the quantity or type of air emissions from large sources locating further than 100 km, may cause adverse impacts on a Class I area's. A reviewing agency should exclude no major new source or major modification from performing an analysis of the proposed source's impact if there is some potential for the source to affect a Class I area's.

The EPA's policy requires, at a minimum, an AQRV impact analysis of any PSD source the emissions from which increase pollutant concentration by more than 1 $\mu g/m^3$ (24-hour average) in a Class I area. However, certain AQRV's may be sensitive to pollutant increases less than 1 $\mu g/m^3$. Also, some Class I areas may be approaching the threshold for effects by a particular pollutant on certain resources and consequently may be sensitive to even small increases in pollutant concentrations. For example, in some cases increases in sulfate concentration less than 1 $\mu g/m^3$ *may adversely* impact visibility. Thus, an increase of 1 $\mu g/m^3$ should not absolutely determine whether an AQRV impact analysis is needed. The reviewing agency should consult the FLM to determine whether to require all the information necessary for a complete AQRV impact analysis of a proposed source.

III.B. PRE-APPLICATION STAGE

A pre-application meeting between the applicant, the FLM, and the reviewing agency to discuss the information required of the source is highly recommended. The applicant should contact the appropriate FLM as soon as plans are begun for a major new source or modification near a Class I area (i.e., generally within 100 km of the Class I area). A preapplication meeting, while not required by regulation, helps the permit applicant understand the data and analyses needed by the FLM. At this point, given preliminary information such as the source's location and the type and quantity of projected air emissions, the FLM can:

- agree on which Class I areas are potentially affected by the source;
- discuss AQRV's for each of the areas(s) and the indicators that may be used to measure the source's impact on those AQRV's;
- advise the source about the scope of the analysis for determining whether the source potentially impacts the Class I area(s);
- discuss which Class I area impact analyses the applicant should include in the permit application; and
- discuss all pre-application monitoring in the Class I area that may be necessary to assess the current status of, and effects on, AQRV's (this monitoring usually is done by the applicant).

III.C. PREPARATION OF PERMIT APPLICATION

For each proposed major new source or major modification that may affect a Class I area, the applicant is responsible for:

- identifying all Class I areas within 100 km of the proposed source and any other Class I areas potentially affected;
- performing all necessary Class I increment analyses (including any necessary cumulative impact analyses);
- performing for each Class I area any preliminary analysis required by a reviewing agency to find whether the source may increase the ambient concentration of any pollutant by 1 $\mu g/m^3$ (24-hour average) or more;
- performing for each Class I area an AQRV impact analysis for visibility;
- providing all information necessary to conduct the AQRV impact analyses (including any necessary cumulative impact analyses);
- performing any monitoring within the Class I area required by the reviewing agency; and
- providing the reviewing agency with any additional relevant information the agency requests to "complete" the Class I area impacts analysis.

By involving the FLM early in preparation of the Class I area analysis, the applicant can identify and address FLM concerns, avoiding delays later during permit review.

The FLM is the AQRV expert for Class I areas. As such, the FLM can recommend to the applicant:

- the AQRV's the applicant should address in the PSD permit application's Class I area impact analysis;
- techniques for analyzing pollutant effects on AQRV's;
- the criteria the FLM will use to determine whether the emissions from the proposed source would have an adverse impact on any AQRV;

- the pre-construction and post-construction AQRV monitoring the FLM will request that the reviewing agency require of the applicant; and

- the monitoring, analysis, and quality assurance/quality control techniques the permit applicant should use in conducting the AQRV monitoring.

The permit applicant and the FLM also should keep the reviewing agency apprised of all discussions concerning a proposed source.

III.D. PERMIT APPLICATION REVIEW

Where a reviewing agency anticipates that a proposed source may affect a Class I area, the reviewing agency is responsible for:

- sending the FLM a copy of any advance notification that an applicant submits within 30 days of receiving such notification;

- sending EPA a copy of each permit application and a copy of any action relating to the source;

- sending the FLM a complete copy of all information relevant to the permit application, including the Class I visibility impacts analysis, within 30 days of receiving it and at least 60 days before any public hearing on the proposed source (the reviewing agency may wish to request that the applicant furnish 2 copies of the permit application);

- providing the FLM a copy of the preliminary determination document; and

- making a final determination whether construction should be approved, approved with conditions, or disapproved.

A reviewing agency's policy regarding Class I area impact analyses can ensure FLM involvement as well as aid permit applicants. Some recommended policies for reviewing agencies are:

- not considering a permit application complete until the FLM certifies that it is "complete" in the sense that it contains adequate information to assess adverse impacts on AQRV's;

- ! recommending that the applicant agree with the FLM (usually well before the application is received) on the type and scope of AQRV analyses to be done;
- ! deferring to the FLM's adverse impact determination, i.e., denying permits based on FLM adverse impact certifications; and
- ! where appropriate, incorporating permit conditions (e.g., monitoring program) which will assure protection of AQRV's. Such conditions may be most appropriate when the full extent of the AQRV impacts is uncertain.

In addition, the reviewing agency can serve as an arbitrator and advisor in FLM/applicant agreements, especially at meetings and in drafting any written agreements.

While the FLM's review of a permit application focuses on emissions impacts on visibility and other AQRV's, the FLM may comment on all other aspects of the permit application. The FLM should be given sufficient time (at least 30 days) to thoroughly perform or review a Class I area impact analysis and should receive a copy of the permit application either at the same time as the reviewing agency or as soon after the reviewing agency as possible.

The FLM can make one of two decisions on a permit application: (1) no adverse impacts; or (2) adverse impact based on any available information. Where a proposed major source or major modification adversely impacts a Class I area's AQRV's, the FLM can recommend that the reviewing agency deny the permit request based on the source's projected adverse impact on the area's AQRV's. However, rather than recommending denial at this point, the FLM may work with the reviewing agency to identify possible permit conditions that, if agreed to by the applicant, would make the source's effect on AQRV's acceptable. In cases where the permit application contains insufficient information for the FLM to determine AQRV impacts, the FLM should notify the reviewing agency that the application is incomplete.

During the public comment period, the FLM can have two roles: 1) final determination on the source's impact on AQRV's with a formal recommendation to the reviewing agency; and 2) a commenter on other aspects of the permit application (best available control technology, modeling, etc.). Even for PSD permit applications where a proposed source's emissions clearly would not cause or contribute to exceedances of any Class I increment, the FLM may demonstrate to the reviewing agency that emissions from the proposed source or modification would adversely impact AQRV's of a mandatory Federal Class I area and recommend denial. Conversely, a permit applicant may demonstrate to the FLM that a proposed source's emissions do not adversely affect a mandatory Federal Class I area's AQRV's even though the modeled emissions would cause an

exceedance of a Class I increment. Where a Class I increment is exceeded, the burden of proving no adverse impact on AQRV's is on the applicant. If the FLM concurs with this demonstration, the FLM may recommend approval of the permit to the reviewing agency and such a permit may be issued despite projected Class I increment exceedances.

IV. VISIBILITY IMPACT ANALYSIS AND REVIEW

Visibility is singled out in the regulations for special protection and enhancement in accordance with the national goal of preventing any future, and remedying any existing, impairment of visibility in Class I areas caused by man-made air pollution. The visibility regulations for new source review (40 CFR 51.307 and 52.27) require visibility impact analysis in PSD areas for major new sources or major modifications that have the potential to impair visibility in any Federal Class I area. Information on screening models available for visibility analysis can be found in the manual "Workbook for Plume Visual Impact Screening and Analysis," EPA-450/4-88-015 (9/88).

IV.A VISIBILITY ANALYSIS

An "adverse impact on visibility" means visibility impairment which interferes with the management, protection, preservation, or enjoyment of a visitor's visual experience of the Federal Class I area. The FLM makes the determination of an adverse impact on a case-by-case basis taking into account the geographic extent, duration, intensity, frequency and time of visibility impairment, and how these factors correlate with (1) times of visitor use of the Federal Class I area, and (2) the frequency and timing of natural conditions that reduce visibility. Visibility perception research indicates that the visual effects of a change in air quality requires consideration of the features of the particular vista as well as what is in the air, and that measurement of visibility usually reflects the change in color, texture, and form of a scene. The reviewing agency may require visibility monitoring in any Federal Class I area near a proposed new major source or modification as the agency deems appropriate.

An integral vista is a view perceived from within a mandatory Class I Federal area of a specific landmark or panorama located outside of the mandatory Class I Federal area. A visibility impact analysis is required for the integral vistas identified at 40 CFR 81, Subpart D, and for any other integral vista identified in a SIP.

IV.B PROCEDURAL REQUIREMENTS

When the reviewing agency receives advance notification (e.g., early consultation with the source prior to submission of the application) of a permit application for a source that may affect visibility in a Federal Class I area, the agency must notify the appropriate FLM within 30 days of receiving the notification. The reviewing agency must, upon receiving a permit application for a source that may affect Federal Class I area visibility, notify the FLM in writing within 30 days of receiving it and at least 60 days prior to the public hearing on the permit application. This written notification must include an analysis of the source's anticipated impact on visibility in any Federal Class I area and all other information relevant to the permit application. The FLM has 30 days after receipt of the visibility impact analysis and other relevant information to submit to the reviewing agency a finding that the source will adversely impact visibility in a Federal Class I area.

If the FLM determines that a proposed source will adversely impact visibility in a Federal Class I area and the reviewing agency concurs, the permit may not be issued. Where the reviewing agency does not agree with the FLM's finding of an adverse impact on visibility the agency must, in the notice of public hearing, either explain its decision or indicate where the explanation can be obtained.

V. BIBLIOGRAPHY

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CHAPTER F

NONATTAINMENT AREA APPLICABILITY

I. INTRODUCTION

Many of the elements and procedures for source applicability under the nonattainment area NSR applicability provisions are similar to those of PSD applicability. The reader is therefore encouraged to become familiar with the terms, definitions and procedures from Part I.A., "PSD Applicability," in this manual. Important differences occur, however, in three key elements that are common to applicability determinations for new sources or modifications of existing sources located in attainment (PSD) and nonattainment areas. Those elements are:

- Definition of "source,"
- Pollutants that must be evaluated (geographic effects); and
- Applicability thresholds

Consequently, this section will focus on these three elements in the context of a nonattaiment area NSR program. Note that the two latter elements, pollutants that must be evaluated for nonattainment NSR due to the location of the source in designated nonattainment areas (geographic effects) and applicability thresholds, <u>are not independent</u>. They will, therefore, be discussed in section III.

II. DEFINITION OF SOURCE

The original NSR regulations required that a source be evaluated according to a ***dual*** source definition. On October 14, 1981, however, the EPA revised the new source review regulations to give a State the option of adopting a ***plantwide*** definition of stationary source in nonattainment areas, if the State's SIP did not rely on the more stringent "dual" definition in its attainment demonstration. Consequently, there are two stationary source definitions for nonattainment major source permitting: a "plantwide" definition and a "dual" source definition. <u>The permit application must use, and be reviewed according to, whichever of the two definitions is used to define a stationary source in the applicable SIP.</u>

II.A. "PLANTWIDE" STATIONARY SOURCE DEFINITION

The EPA definition of stationary source for nonattainment major source permitting uses the "plantwide" definition, which is the same as that used in PSD. A complete discussion of the concepts associated with the plantwide definition of source are presented in the PSD part of this manual (see section II). In essence, this definition provides that only physical or operation changes that result in a significant net emissions increase ***at the entire plant*** are considered a major modification to an existing major source (see sections II and III).

> ***For example, if an existing major source proposes to increase emissions by constructing a new emissions unit but plans to reduce actual emissions by the same amount at another emissions unit at the plant (assuming the reduction is federally enforceable and is the only contemporaneous and creditable emissions change at the source), then there would be no net increase in emissions at the plant and therefore no "major" modification to the stationary source.***

II.B. "DUAL SOURCE" DEFINITION OF STATIONARY SOURCE

The "dual" definition of stationary source defines the term stationary source as ". . . any building, structure, facility, or installation which emits or has the potential to emit any air pollutant subject to regulation under the Clean Air Act." Under this definition, the three terms ***building***, ***structure***, or ***facility*** are defined as a single term meaning ***all*** of the pollutant-emitting activities which belong to the same industrial grouping (i.e.,same two-digit SIC code), are located on one or more adjacent properties, and are under the control of the same owner or operator. The fourth term, ***installation***, means an identifiable piece of process equipment. Therefore, a stationary source is both:

- ! a building, structure, or facility (plantwide); and
- ! an installation (individual piece of equipment).

In other words, the "dual source" definition of stationary source treats each emissions unit as (1) a separate, independent stationary source, and (2) a component of the entire stationary source.

> ***For example, in the case of a power plant with three large boilers each emitting major amounts (i.e., >100 tpy) of NO_x, each of the three boilers is an individual stationary source and all three boilers together constitute a stationary source. [Note that the power plant would be seen only as a single stationary source under the plantwide definition (all three boilers together as one stationary source)].***

Consequently, under the dual source definition, the emissions from each physical or operational change at a plant are reviewed both with and without regard to reductions elsewhere at the plant.

> ***For example, a power plant is an existing major SO_2 source in an SO_2 nonattainment area. The power plant proposes to 1) install SO_2 scrubbers on an existing boiler and 2) construct a new boiler at the same facility. Under the "plantwide" definition, the SO_2 reductions from the scrubber installation could be considered, along with other contemporaneous emissions changes at the plant and the new emissions increase of the new boiler to arrive at the source's net emission increase. This might result in a net***

emissions change which would be below the SO_2 significance level and the new boiler would "net" out of review as major modification. Under the dual source definition, however, the new boiler would be regarded as a individual source and would be subject to nonattainment NSR requirements if its potential emissions exceed the 100 tpy threshold. The emissions reduction from the scrubber could not be used to reduce net source emissions, but would instead be regarded as an SO_2 emissions reduction from a separate source.

The following examples are provided to further clarify the application of the dual source definition to determine if a modification to an existing major source is major and, therefore, subject to major source NSR permitting requirements.

<u>Example 1</u> *An existing major stationary source is located in a nonattainment area for NO_x where the "dual source" definition applies, and has the following emissions units:*

Unit #1 with a potential to emit of 120 tpy of NO_x

Unit #2 with a potential to emit of 80 tpy of NO_x

Unit #3 with a potential to emit of 120 tpy of NO_x

Unit #4 with a potential to emit of 130 tpy of NO_x

Case 1 *A modification planned for Unit #1 will result in an emissions increase of 45 tpy of NO_x. The following emissions changes are contemporaneous with the proposed modification (all case examples assume that increases and decreases are creditable and will be made federally enforceable by the reviewing authority when the modification is permitted and will occur before construction of the modification):*

Unit #3 had an actual decrease of 10 tpy NO_x

Unit #4 had an actual decrease of 10 tpy NO_x

Only contemporaneous emissions changes at Unit #1 are considered because Unit #1 is a major source of NO_x by itself (i.e., potential emissions of NO_x are greater than 100 tpy). The proposed increase at unit #1 of 45 tpy is greater than the 40 tpy NO_x significant emissions rate since the emissions changes at the other units are not considered. Consequently, the proposed modification to Unit #1 is major under the dual source definition.

Case 2 *A modification to unit #2 is planned which will result in an emissions increase of 45 tpy of $N0_x$. The following emissions changes are contemporaneous with the proposed modification:*

Unit #1 had an actual decrease of 10 tpy

Unit #3 had an actual decrease of 10 tpy

Unit #2 is not a major stationary source in and of itself (i.e., its potential to emission of 80 tpy NO_x is less than the 100 tpy major source threshold). Therefore, the major stationary source being modified is the whole plant and the emissions decreases at units #1 and #3 are considered in calculating the net emissions change at the source. The net emissions change of 25 tpy (the sum of +45, -10, and -10) at the source is less than the applicable 40 tpy NO_x significant emissions rate. Consequently, the proposed modification is <u>not</u> major.

Case 3 *A brand new unit #5 with a potential to emission of 45 tpy of NO_x (note that potential emissions are less than the 100 tpy major source cutoff) is being added to the plant. The following emissions changes are contemporaneous with the proposed modification:*

Unit #1 had an actual decrease of 15 tpy

Unit #2 had an actual increase of 25 tpy

Unit #3 had an actual decrease of 20 tpy

The new unit #5 is not a major stationary source in and of itself. Therefore, the major stationary source being modified is the whole plant and the emissions decreases at units #1, #2 and #3 are considered in calculating the net emissions change at the source. The net emissions change of 35 tpy (the sum of + 45, -15, +25, and -20) at the source is less than the applicable 40 tpy NO_x significance level. Therefore, the proposed unit #5 is <u>not</u> a major modification.

Case 4 *A brand new unit #6 with a potential to emit of NO_x of 120 tpy is being added to the plant. Because the new unit is, by itself, a new major source (i.e., potential NO_x emissions are greater than* *the 100 tpy major source cutoff), it cannot net out of review (using emissions reductions achieved at other emissions units at the plant) under the dual source definition.*

<u>Example 2</u> *An existing plant has only two emissions units. The units have a potential to emit of 25 tpy and 40 tpy. Here, any modification to the plant would have to have a potential to emit greater than 100 tpy before the modification is major and subject to review. This is because neither of the two existing emissions units (at 25 tpy and 40 tpy), nor the total plant (at 65 tpy) are considered to be a major source (i.e., existing potential emissions do not exceed 100 tpy). If, however, a third unit with potential emissions of 110 tpy were added, that unit would be subject to review regardless of any emissions reductions from the two existing units.*

III. POLLUTANTS ELIGIBLE FOR REVIEW AND APPLICABILITY THRESHOLDS

III.A. POLLUTANTS ELIGIBLE FOR REVIEW (GEOGRAPHIC CONSIDERATIONS)

A new source will be subject to nonattainment area preconstruction review requirements only if it will emit, or will have the potential to emit, in major amounts any criteria pollutant for which the area has been designated nonattainment. Similarly, only if a modification results in a significant increase (and significant net emissions increase under the plantwide source definition) of a pollutant, for which the source is major and for which the area is designated nonattainment, do nonattainment requirements apply.

III.B. MAJOR SOURCE THRESHOLD

For the purposes of nonattainment NSR, a major stationary source is

! any stationary source which emits or has the potential to emit 100 tpy of any [criteria] pollutant subject to regulation under the CAA, or

! any physical change or change in method of operation at an existing non-major source that constitutes a major stationary source by itself.

Note that the 100 tpy threshold applies to all sources. The alternate 250 tpy major source threshold [for PSD sources not classified under one of the 28 regulated source categories identified in Section 169 of the CAA (See Section I.A.2.3 and Table I-A-1) as being subject to a 100 tpy threshold] does not exist for nonattainment area sources.

III.C. MAJOR MODIFICATION THRESHOLDS

Major modification thresholds for nonattainment areas are those same significant emissions values used to determine if a modification is major for PSD. Remember, however, that only criteria pollutants for which the location of the source has been designated nonattainment are eligible for evaluation.

IV. NONATTAINMENT APPLICABILITY EXAMPLE

The following example illustrates the criteria presented in sections II and III above.

Construction of a new plant with potential emissions of 500 tpy SO_2, 50 tpy VOC and 30 tpy NO_x is proposed for an area designated nonattainment for SO_2 and ozone and attainment for NO_x. (Recall that VOC is the regulated surrogate pollutant for ozone.) The new plant is major for SO_2 and therefore would be subject to nonattainment requirements for SO_2 only. Even though the VOC emissions are significant, the source is minor for VOC, and according to nonattainment regulations, is not subject to major source review. For purposes of PSD, the NO_x emissions are neither major nor significant and are, therefore, not subject to PSD review.

Two years after construction on the new plant commences, a modification of this plant is proposed that will result in an emissions increase of 60 tpy VOC and 35 tpy NO_x without any creditable contemporaneous emissions reductions. Again, the VOC emissions increase would not be subject, because the existing source is not major for VOC. The emissions increase of 35 tpy NO_x is not significant and again, is not subject to PSD review. Note, however, that the plant would be considered a major source of VOC in subsequent applicability determinations.

One year later, the plant proposes another increase in VOC emissions by 75 tpy and NO_x by another 45 tpy, again with no contemporaneous emissions reductions. Because the existing plant is now major for VOC and will experience a significant net emissions increase of that pollutant, it will be subject to nonattainment NSR for VOC. Because the source is major for a regulated pollutant (VOC) and will experience a significant net emissions increase of an attainment pollutant (NO_x), it will also be subject to PSD review.

CHAPTER G

NONATTAINMENT AREA REQUIREMENTS

I. INTRODUCTION

The preconstruction review requirements for major new sources or major modifications locating in designated nonattainment areas differ from prevention of significant deterioration (PSD) requirements. First, the emissions control requirement for nonattainment areas, lowest achievable emission rate (LAER), is defined differently than the best available control technology (BACT) emissions control requirement. Second, before construction of a nonattainment area source can be approved, the source must obtain emissions reductions (offsets) of the nonattainment pollutant from other sources which impact the same area as the proposed source. Third, the applicant must certify that all other sources owned by the applicant in the State are complying with all applicable requirements of the CAA, including all applicable requirements in the State implementation plan (SIP). Fourth, such sources impacting visibility in mandatory class I Federal areas must be reviewed by the appropriate Federal land manager (FLM).

II. LOWEST ACHIEVABLE EMISSION RATE (LAER)

For major new sources and major modifications in nonattainment areas, LAER is the most stringent emission limitation derived from either of the following:

- ! the most stringent emission limitation contained in the implementation plan of any State for such class or category of source; or
- ! the most stringent emission limitation achieved in practice by such class or category of source.

The most stringent emissions limitation contained in a SIP for a class or category of source must be considered LAER, unless (1) a more stringent emissions limitation has been achieved in practice, or (2) the SIP limitation is demonstrated by the applicant to be unachievable. By definition LAER can not be less stringent than any applicable new source performance standard (NSPS).

There is, of course, a range of certainty in such a definition. The greatest certainty for a proposed LAER limit exists when that limit is actually being achieved by a source. However, a SIP limit, even if it has not yet been applied to a source, should be considered initially to be the product of careful investigation and, therefore, achievable. A SIP limit's credibility diminishes if a) no sources exist to which it applies; b) it is generally acknowledged that sources are unable to comply with the limit and the State is in the process of changing the limit; or c) the State has relaxed the original SIP limit. Case-by-case evaluations need to be made in these situations to determine the SIP limit's achievability.

The same logic applies to SIP limits to which sources are subject but with which they are not in compliance. Noncompliance by a source with a SIP limit, even if it is the only source subject to that specific limit, does not automatically constitute a demonstration that the limit is unachievable. The specific reasons for noncompliance must be determined, and the ability of the source to comply assessed. However, such noncompliance may prove to be an indication of nonachievability, so the achievability of such a SIP limitation should be carefully studied before it is used as the basis of a LAER determination. Some recommended sources of information for determining LAER are:

- SIP limits for that particular class or category of sources;
- preconstruction or operating permits issued in other nonattainment areas; and
- the BACT/LAER Clearinghouse.

Several technological considerations are involved in selecting LAER. The LAER is an emissions rate specific to each emissions unit including fugitive emissions sources. The emissions rate may result from a combination of emissions-limiting measures such as (1) a change in the raw material processed, (2) a process modification, and (3) add-on controls. The reviewing agency determines for each new source whether a single control measure is appropriate for LAER or whether a combination of emissions-limiting techniques should be considered.

The reviewing agency also can require consideration of technology transfer. There are two types of potentially transferable control technologies: (1) gas stream controls, and (2) process controls and modifications. For the first type of transfer, classes or categories of sources to consider are those producing similar gas streams that could be controlled by the same or similar technology. For the second type of transfer, process similarity governs the decision.

Unlike BACT, the LAER requirement does not consider economic, energy, or other environmental factors. A LAER is not considered achievable if the cost of control is so great that a major new source could not be built or operated. This applies generically, i.e., if no new plants could be built in that industry if emission limits were based on a particular control technology. If some other plant in the same (or comparable) industry uses that control technology, then such use constitutes evidence that the cost to the industry of that control is not prohibitive. Thus, for a new source, LAER costs are considered only to the degree that they reflect unusual circumstances which in some manner differentiate the cost of control for that source from control costs for the rest of the industry. When discussing costs, therefore, applicants should compare control costs for the proposed source to the costs for sources already using that control.

Where technically feasible, LAER generally is specified as both a numerical emissions limit (e.g., lb/MMBtu) and an emissions rate (e.g., lb/hr). Where numerical levels reflect assumptions about the performance of a control technology, the permit should specify both the numerical emissions rate and limitation and the control technology. In some cases where enforcement of a numerical limitation is judged to be technically infeasible, the permit may specify a design, operational, or equipment standard; however, such standards must be clearly enforceable, and the reviewing agency must still make an estimate of the resulting emissions for offset purposes.

III. EMISSIONS REDUCTIONS "OFFSETS"

A major source or major modification planned in a nonattainment area must obtain emissions reductions as a condition for approval. These emissions reductions, generally obtained from existing sources located in the vicinity of a proposed source, must (1) offset the emissions increase from the new source or modification and (2) provide a net air quality benefit. The obvious purpose of acquiring offsetting emissions decreases is to allow an area to move towards attainment of the NAAQS while still allowing some industrial growth. Air quality improvement may not be realized if all emissions increases are not accounted for and if emissions offsets are not real.

In evaluating a nonattainment NSR permit, the reviewing agency ensures that offsets are developed in accordance with the provisions of the applicable State or local nonattainment NSR rules. The following factors are considered in reviewing offsets :

- the pollutants requiring offsets and amount of offset required;
- the location of offsets relative to the proposed source;
- the allowable sources for offsets;
- the "baseline" for calculating emissions reduction credits; and
- the enforceability of proposed offsets.

Each of these factors should be discussed with the reviewing agency to ensure that the specific requirements of that agency are met.

The offset requirement applies to each pollutant which triggered nonattainment NSR applicability. For example, a permit for a proposed petroleum refinery which will emit more than 100 tpy of sulfur dioxide (SO_2) and particulate matter in a SO_2 and particulate matter nonattainment area is required to obtain offsetting emissions reductions of SO_2 and particulate matter.

III.A. CRITERIA FOR EVALUATING EMISSIONS OFFSETS

Emissions reductions obtained to offset new source emissions in a nonattainment area must meet two important objectives:

- ensure reasonable progress toward attainment of the NAAQS; and
- provide a positive net air quality benefit in the area affected by the proposed source.

States have latitude in determining what requirements offsets must meet to achieve these NAA program objectives. The EPA has set forth minimum considerations under the Interpretive Ruling (40 CFR 51, Appendix S). Acceptable offsets also must be creditable, quantifiable, federally enforceable, and permanent.

While an emissions offset must always result in reasonable progress toward attainment of the NAAQS, it need not show that the area will attain the NAAQS. Therefore, the ratio of required emissions offset to the proposed source's emissions must be greater than one. The State determines what offset ratio is appropriate for a proposed source, taking into account the location of the offsets, i.e., how close the offsets are to the proposed source.

To satisfy the criterion of a net air quality benefit does not mean that the applicant must show an air quality improvement at every location affected by the proposed source. Sources involved in an offset situation should impact air quality in the same general area as the proposed source, but the net air quality benefit test should be made "on balance" for the area affected by the new source. Generally, offsets for VOC's are acceptable if obtained from within the same air quality control region as the new source or from other nearby areas which may be contributing to an ozone nonattainment problem. For all pollutants, offsets should be located as close to the proposed site as possible. Applicants should always discuss the location of potential offsets with the reviewing agency to determine whether the offsets are acceptable.

III.B. AVAILABLE SOURCES OF OFFSETS

In general, emissions reductions which have resulted from some other regulatory action are not available as offsets. For example, emissions reductions already required by a SIP cannot be counted as offsets. Also, sources subject to an NSPS in an area with less stringent SIP limits cannot use the difference between the SIP and NSPS limits as an offset. In addition, any emissions reductions already counted in major modification "netting" may not be used as offsets. However, emissions reductions validly "banked" under an approved SIP may be used as offsets.

III.C. CALCULATION OF OFFSET BASELINE

A critical element in the development or review of nonattainment area new source permits is to determine the appropriate baseline of the source from which offsetting emissions reductions are obtained. In most cases the SIP emissions limit in effect at the time that the permit application is filed may be used. This means that offsets will be based on emissions reductions below these SIP limits. Where there is no meaningful or applicable SIP requirement, the applicant be required to use actual emissions as the baseline emissions level.

III.D. ENFORCEABILITY OF PROPOSED OFFSETS

The reviewing agency ensures that all offsets are federally enforceable. Offsets should be specifically stated and appear in the permit, regulation or other document which establishes a Federal enforceability requirement for the emissions reduction. External offsets must be established by conditions in the operating permit of the other plant or in a SIP revision.

IV. OTHER REQUIREMENTS

An applicant proposing a major new source or major modification in a nonattainment area must certify that all major stationary sources owned or operated by the applicant (or by any entity controlling, controlled by, or under common control with the applicant) in that State are in compliance with all applicable emissions limitations and standards under the CAA. This includes all regulations in an EPA-approved SIP, including those more stringent than Federal requirements.

Any major new source or major modification proposed for a nonattainment area that may impact visibility in a mandatory class I Federal area is subject to review by the appropriate Federal land manager (FLM). The reviewing agency for any nonattainment area should ensure that the FLM of such mandatory class I Federal area receives appropriate notification and copies of all documents relating to the permit application received by the agency.

CHAPTER H

ELEMENTS OF AN EFFECTIVE PERMIT

I. INTRODUCTION

An effective permit is the legal tool used to establish all the source limitations deemed necessary by the reviewing agency during review of the permit application, as described in Parts I and II of this manual, and is the primary basis for enforcement of NSR requirements. In essence, the permit may be viewed as an extension of the regulations. It defines as clearly as possible what is expected of the source and reflects the outcome of the permit review process. A permit may limit the emissions rate from various emissions units or limit operating parameters such as hours of operation and amount or type of materials processed, stored, or combusted. Operational limitations frequently are used to establish a new potential to emit or to implement a desired emissions rate. The permit must be a "stand-alone" document that:

- ! identifies the emissions units to be regulated;
- ! establishes emissions standards or other operational limits to be met;
- ! specifies methods for determining compliance and/or excess emissions, including reporting and recordkeeping requirements; and
- ! outlines the procedures necessary to maintain continuous compliance with the emission limits.

To achieve these goals, the permit, which is in effect a contract between the source and the regulatory agency, must contain specific, clear, concise, and enforceable conditions.

This part of the manual gives a brief overview of the development of a permit, which ensures that major new sources and modifications will be constructed and operated in compliance with the applicable new source review (NSR) regulations [including prevention of signification deterioration (PSD) and nonattainment area (NAA) review], new source performance standards (NSPS), national emissions standards for hazardous air pollutants (NESHAP), and applicable state implementation plan (SIP) requirements. In particular, a permit contains the specific conditions and limitations which ensure that:

- an otherwise major source will remain minor;
- all contemporaneous emissions increases and decreases are creditable and federally-enforceable; and
- where appropriate, emissions offset transactions are documented clearly and offsets are real, creditable, quantifiable, permanent and federally-enforceable.

For a more in-depth study, refer to the Air Pollution Training Institute (APTI) course SI 454 (or Workshop course 454 given by APTI) entitled "Effective Permit Writing." This course is highly recommended for all permit writers and reviewers.

II. TYPICAL CONSTRUCTION PERMIT ELEMENTS

While each final permit is unique to a particular source due to varying emission limits and specific special terms and conditions, every permit must also contain certain basic elements:

- legal authority;
- technical specifications;
- emissions compliance demonstration;
- definition of excess emissions;
- administrative procedures; and
- other specific conditions.

Although many of these elements are inherent in the authority to issue permits under the SIP, they must be explicit within the construction of a NSR permit. Table H-1 lists a few typical subelements found in each of the above. Some permit conditions included in each of these elements can be considered standard permit conditions, i.e., they would be included in nearly every permit. Others are more specific and vary depending on the individual source.

II.A. LEGAL AUTHORITY

In general, the first provision of a permit is the specification of the legal authority to issue the permit. This should include a reference to the enabling legislation and to the legal authority to issue and enforce the conditions contained in the permit and should specify that the application is, in essence, a part of the permit. These provisions are common to nearly all permits and usually are expressed in standard language included in every permit issued by an agency. These provisions articulate the contract-like nature of a permit in that the permit allows a source to emit air pollution only if certain conditions are met. A specific citation of any applicable

TABLE H.1. SUGGESTED MINIMUM CONTENTS OF AIR EMISSION PERMITS

Permit Category	Typical Elements
Legal Authority	Basis--statute, regulation, etc. Conditional Provisions Effective and expiration dates
Technical Specifications	Unit operations covered Identification of emission units Control equipment efficiency Design/operation parameters Equipment design Process specifications Operating/maintenance procedures Emission limits
Emission Compliance Demonstration	Initial performance test and methods Continuous emission monitoring and methods Surrogate compliance measures - process monitoring - equipment design/operations - work practice
Definition of Excess Emissions	Emission limit and averaging time Surrogate measures Malfunctions and upsets Follow-up requirements
Administrative	Recordkeeping and reporting procedures Commence/delay construction Entry and inspections Transfer and severability
Other Conditions	Post construction monitoring Emissions offset

permit effective date and/or expiration date is usually included under the legal authority as well.

II.B. TECHNICAL SPECIFICATIONS

Overall, the technical specifications may be considered the core of the permit in that they specifically identify the emissions unit(s) covered by the permit and the corresponding emission limits with which the source must comply. Properly identifying each emissions unit is important so that (1) inspectors can easily identify the unit in the field and (2) the permit leaves no question as to which unit the various permit limitations and conditions apply. Identification usually includes a brief description of the source or type of equipment, size or capacity, model number or serial number, and the source's identification of the unit.

Emissions and operational limitations are included in the technical specifications and must be clearly expressed, easily measurable, and allow no subjectivity in their compliance determinations. All limits also must be indicated precisely for each emissions point or operation. For clarity, these limits are often best expressed in tabular rather than textual form. In general, it is best to express the emission limits in two different ways, with one value serving as an emissions cap (e.g., lbs/hr.) and the other ensuring continuous compliance at any operating capacity (e.g., lbs/MMBtu). The permit writer should keep in mind that the source must comply with <u>both</u> values to demonstrate compliance. Such limits should be of a short term nature, continuous and enforceable. In addition, the limits should be consistent with the averaging times used for dispersion modeling and the averaging times for compliance testing. Since emissions limitation values incorporated into a permit are based on a regulation (SIP, NSPS, NESHAP) or resulting from new source review, (i.e., BACT or LAER requirements), a reference to the applicable portion of the regulation should be included.

II.C. EMISSIONS COMPLIANCE DEMONSTRATION

The permit should state how compliance with each limitation will be determined, and include, but is not limited to, the test method(s) approved for demonstrating compliance. These permit compliance conditions must be very clear and enforceable as a practical matter (see Appendix C). The conditions must specify:

- when and what tests should be performed;
- under what conditions tests should be performed;
- the frequency of testing;
- the responsibility for performing the test;
- that the source be constructed to accommodate such testing;
- procedures for establishing exact testing protocol; and
- requirements for regulatory personnel to witness the testing.

Where continuous, quantitative measurements are infeasible, surrogate parameters must be expressed in the permit. Examples of surrogate parameters include: mass emissions/opacity correlations, maintaining pressure drop across a control (e.g., venturi throat of a scrubber), raw material input/mass emissions output ratios, and engineering correlations associated with specific work practices. These alternate compliance parameters may be used in conjunction with measured test data to monitor continuous compliance or may be independent compliance measures where source testing is not an option and work practice or equipment parameters are specified. Only those parameters that exhibit a correlation with source emissions should be used. Identifying and quantifying surrogate process or control equipment parameters (such as pressure drop) may require initial source testing or may be extracted from confirmed design characteristics contained in the permit application.

Parameters that must be monitored either continuously or periodically should be specified in the permit, including averaging time for continuously monitored data, and data recording frequency for periodically (continually) monitored data. The averaging times should be of a short term nature consistent with the time periods for which dispersion modeling of the respective emissions rate demonstrated compliance with air quality standards, and consistent with averaging times used in compliance testing. This requirement also applies to surrogate parameters where compliance may be time-based, such as weekly or monthly leak detection and repair programs (also see Appendix C). Whenever possible, "never to be exceeded" values should be specified for surrogate compliance parameters. Also, operating and maintenance (O&M) procedures should be specified for the monitoring instruments (such as zero, span, and other periodic checks) to ensure that valid data are obtained. Parameters which must be monitored continuously or continually are those used by inspectors to determine compliance on a real-time basis and by source personnel to maintain process operations in compliance with source emissions limits.

II.D. DEFINITION OF EXCESS EMISSIONS

The purpose of defining excess emissions is to prevent a malfunction condition from becoming a standard operating condition by requiring the source to report and remedy the malfunction. Conditions in this part of the permit:

- precisely define excess emissions;
- outline reporting requirements;
- specify actions the source must take; and
- indicate time limits for correction by the source.

Permit conditions defining excess emissions may include alternate conditions for startup, shutdown, and malfunctions such as maximum emission limits and operational practices and limits. These must be as specific as possible since such exemptions can be misused. Every effort should be made to include adequate definitions of both preventable and nonpreventable malfunctions. Preventable malfunctions usually are those which cause excess emissions due to negligent maintenance practices. Examples of preventable malfunctions may include: leakage or breakage of fabric filter bags; baghouse seal ruptures; fires in electrostatic precipitators due to excessive build up of oils or other flammable materials; and failure to monitor and replace spent activated carbon beds in carbon absorption units. These examples reinforce the need for good O&M plans and keeping records of all repairs. Permit requirements concerning malfunctions may include: timely reporting of the malfunction duration, severity, and cause; taking interim and corrective actions; and taking actions to prevent recurrence.

II.E. ADMINISTRATIVE PROCEDURES

The administrative elements of permits are usually standard conditions informing the source of certain responsibilities. These administrative procedures may include:

- recordkeeping and reporting requirements, including all continuous monitoring data, excess emission reports, malfunctions, and surrogate compliance data;
- notification requirements for performance tests, malfunctions, commencing or delay of construction;
- entry and inspection procedures;
- the need to obtain a permit to operate; and
- specification of procedures to revoke, suspend, or modify the permit.

Though many of these conditions will be entered into the permit via standard permit conditions, the reviewer must ensure the language is adequate to establish precisely what is expected or needed from the source, particularly the recordkeeping requirements.

II.F. OTHER CONDITIONS

In some cases, specific permit conditions which do not fit into the above elements may need to be outlined. Examples of these are conditions requiring: the permanent shutdown of (or reduced emissions rates for) other emissions units to create offsets or netting credits; post-construction monitoring; continued Statewide compliance; and a water truck to be dedicated solely to a haul road. In the case of a portable source, a condition may be included to require a copy of the effective permit to be on-site at all times. Some O&M procedures, such as requiring a 10 minute warmup for an incinerator, would be included in this category, as well as conditions requiring that replacement fabric filters and baghouse seals be kept available at all times. Any source-specific condition which needs to be included in the permit to ensure compliance should be listed here.

III. SUMMARY

Assuming a comprehensive review, a permit is only as clear, specific, and effective as the conditions it contains. As such, Table H-2 on the following page lists guidelines for drafting actual permit conditions. The listing specifies how typical permit elements should be written. For further discussion on drafting "federally enforceable" permit conditions as a practical matter, please refer to Appendix C - "Potential to Emit."

TABLE H.2. GUIDELINES FOR WRITING EFFECTIVE SPECIFIC CONDITIONS IN NSR PERMITS

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1. Make each permit condition ***simple, clear***, and ***specific*** such that it "stands alone."

2. Make certain ***legal authority*** exists to specify conditions.

3. Permit conditions should be ***objective*** and ***meaningful***.

4. Provide description of ***processes, emissions units*** and ***control equipment*** covered by the permit, including operating rates and periods.

5. Clearly ***identify each permitted emissions unit*** such that it can be located in the field.

6. Specify allowable emissions (or concentration, etc.) rates for ***each pollutant and emissions unit*** permitted, and specify each applicable emissions standard by name in the permit.

7. Allowable emissions rates should reflect the conditions of ***BACT/LAER*** and ***Air Quality Analyses*** (e.g., specify limits two ways: maximum mass/unit of process ***and*** maximum mass/unit time)

8. Specify for all emissions units (especially fugitive sources) permit conditions that require ***continuous application of BACT/LAER*** to achieve maximum degree of emissions reduction.

9. Initial and subsequent performance tests should be conducted at worst case operating (non-malfunction) conditions for all emissions units. Performance tests should determine ***both emissions and control equipment efficiency***.

10. Continual and continuous ***emissions performance monitoring*** and recordkeeping (direct and/or surrogate) should be specified where feasible.

11. Specify ***test method*** (citation) and ***averaging period*** by which all compliance demonstrations (initial and continuous) are to be made.

12. Specify what ***conditions*** constitute ***"excess emissions,"*** and what is to be done in those cases.

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CHAPTER I

PERMIT DRAFTING

I. RECOMMENDED PERMIT DRAFTING STEPS

This section outlines a recommended five-step permit drafting process (see Table I-1). These steps can assist the writer in the orderly preparation of air emissions permits following technical review.

Step 1 concerns the emissions units and requires the listing and specification of three things. First, list each new or modified emissions unit. Second, specify each associated emissions point. This includes fugitive emissions points (e.g., seals, open containers, inefficient capture areas, etc.) and fugitive emissions units (e.g., storage piles, materials handling, etc.). Be sure also to note emissions units with more than one ultimate exhaust and units sharing common exhausts. Third, the writer must describe each emissions unit as it may appear in the permit and identify, as well as describe, each emissions control unit. Each new or modified emissions unit identified in Step 1 that will emit or increase emissions of any pollutant is considered in Step 2.

Step 2 requires the writer to specify each pollutant that will be emitted from the new or modified source. Some pollutants may not be subject to regulation or are of de minimis amounts such that they do not require major source review. All pollutants should be identified in this step and reviewed for applicability. Federally enforceable conditions must be identified for de minimis pollutants to ensure they do not become significant (see Appendix C - Potential to Emit). An understanding of "potential to emit" is pertinent to permit review and especially to the drafting process.

TABLE I-1. FIVE STEPS TO PERMIT DRAFTING

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STEP 1. SPECIFY EMISSIONS UNITS

- ! Identify each new (or modified) emissions unit that will emit (or increase) any pollutant.
- ! Identify any pollutant and emissions units involved in a netting or emissions reduction proposal (i.e., all contemporaneous emissions increases and decreases).
- ! Include point and fugitive emissions units.
- ! Identify and describe emissions unit and emissions control equipment.

STEP 2. SPECIFY POLLUTANTS

- ! Pollutants subject to NSR/PSD.
- ! Pollutants not subject to NSR/PSD but could reasonably be expected to exceed significant emissions levels. Identify conditions that ensure de minimis (e.g., shutdowns, operating modes, etc..).

STEP 3. SPECIFY ALLOWABLE EMISSION RATES AND BACT/LAER REQUIREMENTS

- ! Minimum number of allowable emissions rates specified is equal to at least two limits per pollutant per emissions unit.
- ! One of two allowable limits is unit mass per unit time (lbs/hr) which reflects application of emissions controls at maximum capacity.
- ! Maximum hourly emissions rate must correspond to that used in air quality analysis.
- ! Specify BACT/LAER emissions control requirements for each pollutant/emissions unit pair.

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TABLE I-1. - Continued

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STEP 4. SPECIFY COMPLIANCE DEMONSTRATION METHODS

- Continuous, direct emission measurement is preferable.
- Specify initial and periodic emissions testing where necessary.
- Specify surrogate (indirect) parameter monitoring and recordkeeping where direct monitoring is impractical or in conjunction with tested data.
- Equipment and work practice standards should complement other compliance monitoring.

STEP 5. OTHER PERMIT CONDITIONS

- Establish the basis upon which permit is granted (legal authority).
- Should be used to minimize "paper" allowable emissions.
- Federally enforceable permit conditions limiting potential to emit.

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Step 3 pools the data collected in the two previous steps. The writer should specify the pollutants that will be emitted from each emission unit and identify associated emission controls for each pollutant and/or emission unit. (Indicate if the control has been determined to be BACT.) The writer also must assess the minimum number of allowable emissions rates to be specified in the permit. Each emissions unit should have at least two allowable emissions rates for each pollutant to be emitted. This is the most concise manner in which to present permit allowables and should be consistent with the averaging times and emissions ratio used in the air quality analysis. As discussed earlier in Section H, the applicable regulation should also be cited as well as whether BACT, LAER, or other SIP requirements apply to each pollutant to be regulated.

Step 4 essentially mirrors the items discussed in the previous Chapter H, Section IV., Emissions Compliance Demonstration. At this point the writer enters into the permit any performance testing required of the source. The conditions should specify what emissions test is to be performed and the frequency of testing. Any surrogate parameter monitoring must be specified. Recordkeeping requirements and any equipment and work practice standards needed to monitor the source's compliance should be written into the permit in Step 4. Any remaining or additional permit conditions, such as legal authority and conditions limiting potential to emit can be identified in ***Step 5***. (Other Permit Conditions, see Table I-1.) At this point, the permit should be complete. The writer should review the draft to ensure that the resultant permit is an effective tool to monitor and enforce source compliance. Also, the compliance inspector should review the permit to ensure that the permit conditions are enforceable as a practical matter.

II. PERMIT WORKSHEETS AND FILE DOCUMENTATION

Some agencies use permit drafting worksheets to store all the required information that will be incorporated into the permit. The worksheets may be helpful and are available at various agencies and in other EPA guidance documents. The worksheets serve as a summary of the review process, though this summation should appear in the permit file with or without a worksheet. Documenting the permit review process in the file cannot be overemphasized. The decision-making process which leads to the final permit for a source must be clearly traceable through the file. When filing documentation, the reviewer must also be aware of any confidential materials. Many agencies have special procedures for including confidential information in the permit file. The permit reviewer should follow any special procedures and ensure the permit file is documented appropriately.

III. SUMMARY

Listed below are summary "helpful hints" for the permit writer, which should be kept in mind when reviewing and drafting the permit. Many of these have been touched on throughout Part III, but are summarized here to help ensure that they are not overlooked:

! Document the review process throughout the file.

! Be aware of confidentiality items, procedures, and the consequences of the release of such information.

! Ensure the application includes all pertinent review information (e.g., has the applicant identified solvents used in some coatings; are solvents used, then later recovered; ultimate disposal of collected wastes identified; and applicable monitoring and modeling results included).

! Address secondary pollutant formation.

! Ensure that all applicable regulations and concerns have been addressed (e.g., BACT, LAER, NSPS, NESHAP, non-regulated toxics, SIP, and visibility).

- ! Ensure the permit is organized well, e.g., conditions are independent of one another, and conditions are grouped so as not be cover more than one area at a time.

- ! Surrogate parameters listed are clear and obtainable.

- ! Emissions limits are clear. In cases of multiple or common exhaust, limits should specify if per emissions unit or per exhaust.

- ! Every permit condition is 1) reasonable, 2) meaningful, 3) monitorable, and 4) always enforceable as a practical matter.

APPENDIX A - DEFINITION OF SELECTED NSR TERMS

BACT	Best Available Control Technology is the control level required for sources subject to PSD. From the regulation (reference 40 CFR 52.21(b)) BACT means "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."
Emission Units	The individual emitting facilities at a location that together make up the source. From the regulation (reference 40 CFR 52.21(b)), it means "any part of a stationary source which emits or would have the potential to emit any pollutant subject to regulation under the Act."
Increments	The maximum permissible level of air quality deterioration that may occur beyond the baseline air quality level. Increments were defined statutorily by Congress for SO_2 and PM. Recently EPA also has promulgated increments for NO_x. Increment is consumed or expanded by actual emissions changes occurring after the baseline date and by construction related actual emissions changes occurring after January 6, 1975, and February 8, 1988 for PM/SO_2 and NO_x, respectively.

Innovative Control Technology	From the regulation (reference 40 CFR 52.21(b)(19)) "Innovative control technology" means any system of air pollution control that has not been adequately demonstrated in practice, but would have a substantial likelihood of achieving greater continuous emissions reduction than any control system in current practice or of achieving at least comparable reductions at lower cost in terms of energy, economics, or nonair quality environmental impacts. Special delayed compliance provisions exist that may be applied when applicants propose innovative control techniques.
LAER	Lowest Achievable Emissions Rate is the control level required of a source subject to nonattainment review. From the regulations (reference 40 CFR 51.165(a)), it means for any source "the more stringent rate of emissions based on the following: (a) The most stringent emissions limitation which is contained in the implementation plan of any State for such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or (b) The most stringent emissions limitation which is achieved in practice by such class or category of stationary sources. This limitation, when applied to a modification, means the lowest achievable emissions rate of the new or modified emissions units within a stationary source. In no event shall the application of the term permit a proposed new or modified stationary source to emit any pollutant in excess of the amount allowable under an applicable new source standard of performance."

APPENDIX A - DEFINITION OF SELECTED NSR TERMS (Continued)

Major Modification	A major modification is a modification to an existing major stationary source resulting in a significant net emissions increase (defined elsewhere in this table) that, therefore, is subject to PSD review. From the regulation (reference 40 CFR 52.21(b)(2)): "(i) `Major modification' means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act. (ii) Any net emissions increase that is significant for volatile organic compounds shall be considered significant for ozone. (iii) A physical change or change in the method of operation shall not include: (a) routine maintenance, repair and replacement; (c) use of an alternative fuel by reason of an order or rule under Section 125 of the Act; (d) Use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste; (e) Use of an alternative fuel or raw material by a stationary source which: (1) The source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any Federally enforceable permit condition which was established after January 6, 1975, pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR Subpart I or 40 CFR 51.166; or (2) The source is approved to use under any permit issued under 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.166; (f) an increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975, pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR Subpart I or 40 CFR 51.166; or (g) any change in ownership at a stationary source."

Major Stationary Source A major stationary source is an emissions source of sufficient size to warrant PSD review. Major modification to major stationary sources are also subject to PSD review. From the regulation (reference 40 CFR 52.21(b)(1)), (i) "Major stationary source" means:

"(a) Any of the following stationary sources of air pollutant which emits, or has the potential to emit, 100 tons per year or more of any pollutant subject to regulation under the Act: Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input, coal cleaning plants (with thermal dryers), Kraft pulp mills, Portland cement plants, primary zinc smelters, iron and steel mill plants, primary aluminum ore reduction plants, primary aluminum ore reduction plants, primary copper smelters, municipal incinerators capable of charging more than 250 tons of refuse per day, hydrofluoric, sulfuric, and nitric acid plants, petroleum refineries, lime plants, phosphate rock processing plants, coke oven batteries, sulfur recovery plants, carbon black plants (furnace process), primary lead smelters, fuel conversion plants, sintering plants, secondary metal production plants, chemical process plants, fossil fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input, petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels, taconite ore processing plants, glass fiber processing plants, and charcoal production plants;

(b) Notwithstanding the stationary source size specified in paragraph (b)(1)(i) of this section, any stationary source which emits, or has the potential to emit, 250 tons per year or more of any air pollutant subject to regulation under the Act; or

(c) Any physical change that would occur at a stationary source not otherwise qualifying under paragraph (b)(1) as a major stationary source not otherwise qualifying under paragraph (b)(1) as a major stationary source, if the changes would constitute a major stationary source by itself.

(ii) A major stationary source that is major for volatile organic compounds shall be considered major for ozone."

NAAQS National Ambient Air Quality Standards are Federal standards for the minimum ambient air quality needed to protect public health and welfare. They have been set for six criteria pollutants including SO_2, PM/PM_{10}, NO_x, CO, O_3 (VOC), and Pb.

APPENDIX A - DEFINITION OF SELECTED NSR TERMS (Continued)

NESHAP NESHAP, or National Emission Standard for Hazardous Air Pollutants, is a technology-based standard of performance prescribed for hazardous air pollutants from certain stationary source categories under Section 112 of the Clean Air Act. Where they apply, NESHAP represent absolute minimum requirements for BACT.

NSPS NSPS, or New Source Performance Standard, is an emission standard prescribed for criteria pollutants from certain stationary source categories under Section 111 of the Clean Air Act. Where they apply, NSPS represent absolute minimum requirements for BACT.

PSD Prevention of significant deterioration is a construction air pollution permitting program designed to ensure air quality does not degrade beyond the NAAQS levels or beyond specified incremental amounts above a prescribed baseline level. PSD also ensures application of BACT to major stationary sources and major modifications for regulated pollutants and consideration of soils, vegetation, and visibility impacts in the permitting process.

Regulated Pollutants[6] Refers to pollutants that have been regulated under the authority of the Clean Air Act (NAAQS, NSPS, NESHAP):

O_3 (VOC)- Ozone, regulated through volatile organic compounds as precursors
NO_x - Nitrogen oxides
SO_2 - Sulfur dioxide
PM (TSP)- Total suspended particulate matter
PM (PM_{10})- Particulate matter with $\leq$10 micron aerometric diameter
CO - Carbon monoxide

Pb	- Lead	5	TRS	- Total reduced sulfur (including H_2S)
As	- Asbestos	5	RDS	- Reduced Sulfur Compounds (including H_2S)
Be	- Beryllium	5	Bz	- Benzene
Hg	- Mercury	5	Rd	- Radionuclides
VC	- Vinyl chloride	5	As	- Arsenic
F	- Fluorides	5	CFC's	- Chlorofluorocarbons
H_2SO_4	- Sulfuric acid mist	5	Rn-222	- Radon-222
H_2S	- Hydrogen sulfide	5	Halons	

[6] The referenced list of regulated pollutants is current as of November 1989. Presently, additional pollutants may also be subject to regulation under the Clean Air Act.

Significant Emissions Increase For new major stationary sources and major modifications, a significant emissions increase triggers PSD review. Review requirements must be met for each pollutant undergoing a significant net emissions increase. From the regulation (reference 40 CFR 52.21(b)(23)).

(i) "Significant" means, in reference to a net emissions increase from a modified major source or the potential of a new major source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates:

Carbon monoxide: 100 tons per year (tpy)
Nitrogen oxides: 40 tpy
Sulfur dioxide: 40 tpy
Particulate matter: 25 tpy
PM10: 15 tpy
Ozone: 40 tpy of volatile organic compounds
Lead: 0.6 tpy
Asbestos: 0.007 tpy
Beryllium: 0.0004 tpy
Mercury: 0.1 tpy
Vinyl chloride: 1 tpy
Fluorides: 3 tpy
Sulfuric acid mist: 7 tpy
Hydrogen Sulfide (H_2S): 10 tpy
Total reduced sulfur (including H_2S): 10 tpy
Reduced sulfur compounds (including H_2S): 10 tpy

(ii) "Significant" means, in reference to a net emissions increase or the potential of a source to emit a pollutant subject to regulation under the Act, that (i) above does not list, any emissions rate.

(For example, benzene and radionuclides are pollutants falling into the "any emissions rate" category.)

(iii) Notwithstanding, paragraph (b)(23)(i) of this section, "significant means any emissions rate or any net emissions increase associated with a major stationary source or major modification which would construct within 10 kilometers of a Class I area, and have an impact on such an area equal to or greater than 1 ug/m^3, (24-hour average).

APPENDIX A - DEFINITION OF SELECTED NSR TERMS (Continued)

SIP	State Implementation Plan is the federally approved State (or local) air quality management authority's statutory plan for attaining and maintaining the NAAQS. Generally, this refers to the State/local air quality rules and permitting requirements that have been accepted by EPA as evidence of an acceptable control strategy.
Stationary Source	For PSD purposes, refers to all emissions units at one location under common ownership or control. From the regulation (reference 40 CFR 52.21(b)(5) and 51.166(b)(5)), it means "any building, structure, facility, or installation which emits or may emit any air pollutant subject to regulation under the Act." "Building, structure, facility, or installation" means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or person under common control). Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same first two digit code) as described in the Standard Industrial Classification Manual, 1972, as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0066 and 003-005-00176-0, respectively).

APPENDIX B

ESTIMATING CONTROL COSTS

APPENDIX B - ESTIMATING CONTROL COSTS

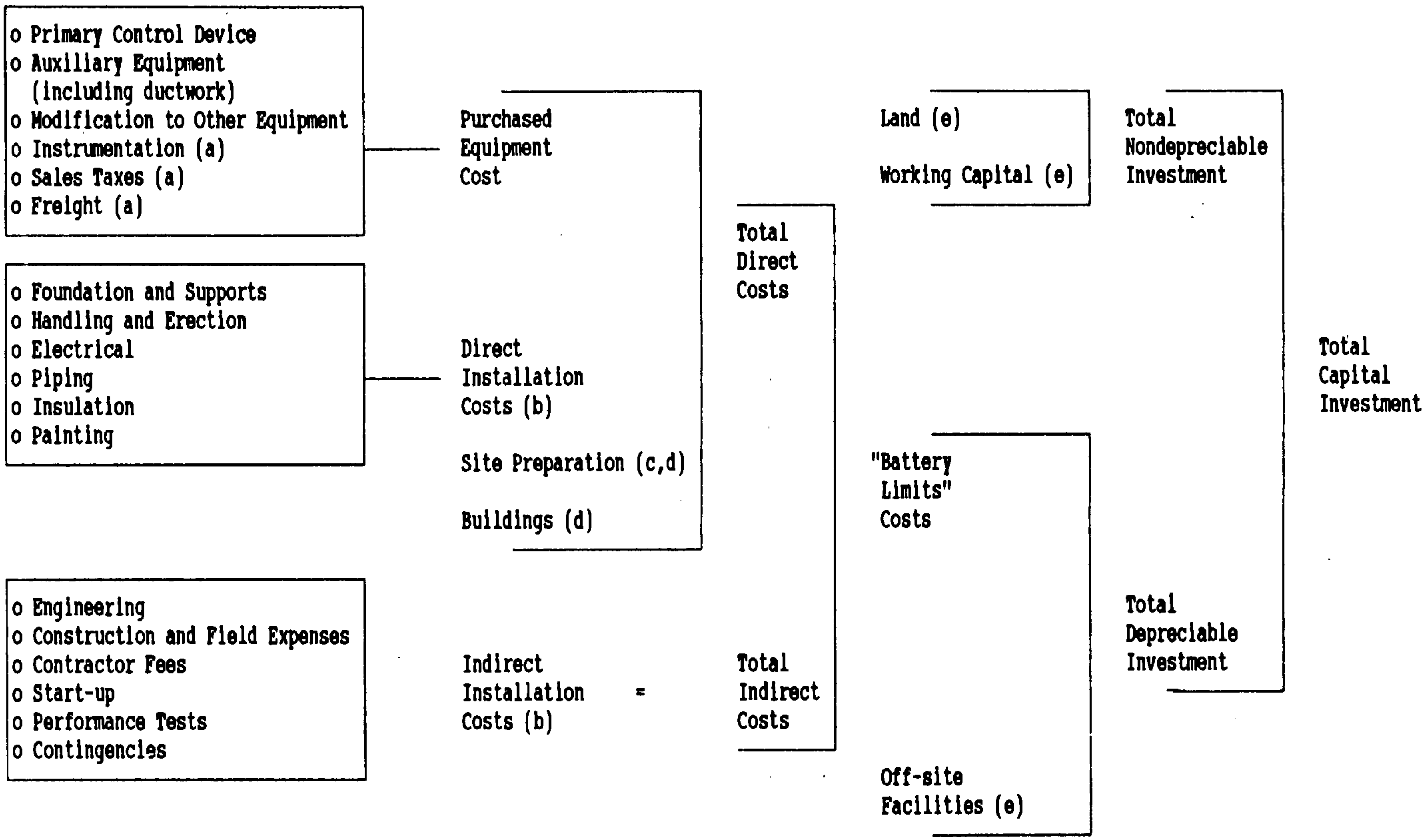
I. CAPITAL COSTS

Capital costs include equipment costs, installation costs, indirect costs, and working capital (if appropriate). Figure B-4 presents the elements of total capital cost and represents a building block approach that focuses on the control device as the basic unit of analysis for estimating total capital investment. The total capital investment has a role in the determination of total annual costs and cost effectiveness.

One of the most common problems which occurs when comparing costs at different facilities is that the battery limits are different. For example, the battery limit of the cost of a electrostatic precipitation might be the precipitator itself (housing, plates, voltage regulators, transformers, etc.), ducting from the source to the precipitator, and the solids handling system. The stack would not be included because a stack will be required regardless of whether or not controls are applied. Therefore, it should be outside the battery limits of the control system.

Direct installation costs are the costs for the labor and materials to install the equipment and includes site preparation, foundations, supports, erection and handling of equipment, electrical work, piping, insulation and painting. The equipment vendor can usually supply direct installation costs.

The equipment vendor should be able to supply direct installation costs estimates or general installation costs factors. In addition, typical installation cost factors for various types of equipment are available in the following references.



(a) These costs are factored from the sum of the control device and auxiliary equipment costs.
(b) These costs are factored from the purchased control equipment.
(c) Usually required only at "grass roots" installations.
(d) Unlike the other direct and indirect costs, costs for these items are not factored from the purchased equipment cost. Rather, they are sized and costed separately.
(e) Normally not required with add-on control systems.

FIGURE B-4. Elements of Total Capital Costs

- OAQPS Control Cost Manual (Fourth Edition), January 1990, EPA 450/3-90-006
- Control Technology for Hazardous Air Pollutants (HAPS) Manual, September 1986, EPA 625/6-86-014
- Standards Support Documents
  - Background Information Documents
  - Control Techniques Guidelines Documents
- Other EPA sponsored costing studies
- Engineering Cost and Economics Textbooks
- Other engineering cost publications

These references should also be used to validate any installation cost factors supplied from equipment vendors.

If standard costing factors are used, they may need to be adjusted due to site specific conditions. For example, in Alaska installation costs are on the order of 40-50 percent higher than in the contiguous 48 states due to higher labor prices, shipping costs, and climate.

Indirect installation costs include (but are not limited to) engineering, construction, start-up, performance tests, and contingency. Estimates of these costs may be developed by the applicant for the specific project under evaluation. However, if site-specific values are not available, typical estimates for these costs or cost factors are available in:

- OAQPS Control Cost Manual (Fourth Edition), EPA 450/3-90-006
- Cost Analysis Manual for Standards Support Documents, April 1979

These references can be used by applicants if they do not have site-specific estimates already prepared, and should also be used by the reviewing agency to determine if the applicant's estimates are reasonable.

Where an applicant uses different procedures or assumptions for estimating control costs than contained in the referenced material or outlined in this document, the nature and reason for the differences are to be documented in the BACT analysis.

Working capital is a fund set aside to cover initial costs of fuel, chemicals, and other materials and other contingencies. Working capital costs for add on control systems are usually relatively small and, therefore, are usually not included in cost estimates.

Table B-11 presents an illustrative example of a capital cost estimate developed for an ESP applied to a spreader-stoker coal-fired boiler. This estimate shows the minimum level of detail required for these types of estimates. If bid costs are available, these can be used rather than study cost estimates.

II. TOTAL ANNUAL COST

The permit applicant should use the levelized annual cost approach for consistency in BACT cost analysis. This approach is also called the "Equivalent Uniform Annual Cost" method, or simply "Total Annual Cost" (TAC). The components of total annual costs are their relationships are shown in Figure B-5. The total annual costs for control systems is comprised of three elements: "direct" costs (DC), "indirect costs" (IC), and "recovery credit" (RC), which are related by the following equation:

$$TAC = DC + IC - RC$$

TABLE B-11. EXAMPLE OF A CAPITAL COST ESTIMATE FOR AN ELECTROSTATIC PRECIPITATOR

	Capital cost ($)
Direct Investment	
Equipment cost	
ESP unit	175,800
Ducting	64,100
Ash handling system	97,200
Total equipment cost	337,100
Installation costs	
ESP unit	175,800
Ducting	102,600
Ash handling system	97,200
Total installation costs	375,600
Total direct investment (TDI) (equipment + installation)	712,700
Indirect Investment	71,300
Engineering (10% of TDI)	71,300
Construction and field expenses (10% of TDI)	71,300
Construction fees (10% of TDI)	71,300
Start-up (2% of TDI)	14,300
Performance tests (minimum $2000)	3,000
Total indirect investment (TII)	231,200
Contingencies (20% of TDI + TII)	188,800
TOTAL TURNKEY COSTS (TDI + TII)	1,132,700
Working Capital (25% of total direct operating costs)a	21,100
GRAND TOTAL	1,153,800

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+)))))))))))))))))))))))))))),
*  o Raw Materials            *
*  o Utilities                *            S))))))))))),
*     - Electricity           /))))))))) Variable      *
*     - Steam                 *                        *
*     - Water                 *                        *     S)))))))),
*     - Others                *                        *              *
.))))))))))))))))))))))))))))-                         *    Direct    *
                                                       /))) Annual    *
+)))))))))))))))))))))))))))),                         *    Costs     *
* o Labor                     *                        *              *
*   - Operating               *                        *              *
*   - Supervisory             /))))))))) Semivariable  *              *
*   - Maintenance             *            S)))))))))))-              *
* o Maintenance materials     *                             +         *
* o Replacement parts         *                                       *     Total
.))))))))))))))))))))))))))))-                                        *  =  Annual
                                                                      *     Costs
                              +))))))))))))))))))))),                 *
                              * o Overhead          *        Indirect *
                              * o Property Taxes    /)))))))) Annual   *
                              * o Insurance         *        Costs    *
                              * o Capital Recovery  *                 *
                              .)))))))))))))))))))))-           -     *
                              +))))))))))))))))))))),                 *
                              * o Recovered Product*         Recovery *
                              * o Recovered Energy  /))))))  Credits  *
                              * o Useful byproduct  *                 *
                              * o Energy Gain       *        S))))))))-
                              .)))))))))))))))))))))-
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FIGURE B-5. Elements of Total Annual Costs

Direct costs are those which tend to be proportional or partially proportional to the quantity of exhaust gas processed by the control system or, in the case of inherently lower polluting processes, the amount of material processed or product manufactured per unit time. These include costs for raw materials, utilities (steam, electricity, process and cooling water, etc.), and waste treatment and disposal. Semivariable direct costs are only partly dependent upon the exhaust or material flowrate. These include all associated labor, maintenance materials, and replacement parts. Although these costs are a function of the operating rate, they are not linear functions. Even while the control system is not operating, some of the semivariable costs continue to be incurred.

Indirect, or "fixed", annual costs are those whose values are relatively independent of the exhaust or material flowrate and, in fact, would be incurred even if the control system were shut down. They include such categories as overhead, property taxes, insurance, and capital recovery.

Direct and indirect annual costs are offset by recovery credits, taken for materials or energy recovered by the control system, which may be sold, recycled to the process, or reused elsewhere at the site. These credits, in turn, may be offset by the costs necessary for their purification, storage, transportation, and any associated costs required to make then reusable or resalable. For example, in auto refinishing, a source through the use of certain control technologies can save on raw materials (i.e., paint) in addition to recovered solvents. A common oversight in BACT analyses is the omission of recovery credits where the pollutant itself has some product or process value. Examples of control techniques which may produce recovery credits are equipment leak detection and repair programs, carbon absorption systems, baghouse and electrostatic precipitators for recovery of reusable or saleable solids and many inherently lower polluting processes.

Table B-12 presents an example of total annual costs for the control system previously discussed. Direct annual costs are estimated based on system design power requirements, energy balances, labor requirements, etc., and raw materials and fuel costs. Raw materials and other consumable costs should be carefully reviewed. The applicant generally should have documented delivered costs for most consumables or will be able to provide documented estimates. The direct costs should be checked to be sure they are based on the same number of hours as the emission estimates and the proposed operating schedule.

Maintenance costs in some cases are estimated as a percentage of the total capital investment. Maintenance costs include actual costs to repair equipment and also other costs potentially incurred due to any increased system downtime which occurs as a result of pollution control system maintenance.

Fixed annual costs include plant overhead, taxes, insurance, and capital recovery charges. In the example shown, total plant overhead is calculated as the sum of 30 percent of direct labor plus 26 percent of all labor and maintenance materials. The OAQPS Control Cost Manual combines payroll and plant overhead into a single indirect cost. Consequently, for "study" estimates, it is sufficiently accurate to combine payroll and plant overhead into a single indirect cost. Total overhead is then calculated as 60 percent of the sum of all labor (operating, supervisory, and maintenance) plus maintenance materials.

Property taxes are a percentage of the fixed capital investment. Note that some jurisdictions exempt pollution control systems from property taxes. Ad valorem tax data are available from local governments. Annual insurance charges can be calculated by multiplying the insurance rate for the facility by the total capital costs. The typical values used to calculate taxes and

TABLE B-12. EXAMPLE OF A ANNUAL COST ESTIMATE FOR AN ELECTROSTATIC PRECIPITATOR APPLIED TO A COAL-FIRED BOILER

	Annual costs ($/yr)
Direct Costs	
Direct labor at $12.02/man-hour	26,300
Supervision at $15.63/man-hour	0
Maintenance labor at $14.63/man-hour	16,000
Replacement parts	5,200
Electricity at $0.0258/kWh	3,700
Water at $0.18/1000 gal	300
Waste disposal at $15/ton (dry basis)	33,000
Total direct costs	84,500
Indirect Costs	
Overhead	
Payroll (30% of direct labor)	7,900
Plant (26% of all labor and replacement parts)	12,400
Total overhead costs	20,300
Capital charges	
G&A taxes and insurance (4% of total turnkey costs)	45,300
Capital recovery factor (11.75% of total turnkey costs)	133,100
Interest on working capital (10% of working capital)	2,100
Total capital charges	180,500
TOTAL ANNUALIZED COSTS	**285,300**

insurance is four percent of the total capital investment if specific facility data are not readily available.

The annual costs previously discussed do not account for recovery of the capital cost incurred. The capital cost shown in Table B-2 is annualized using a capital recovery factor of 11.75 percent. When the capital recovery factor is multiplied by the total capital investment the resulting product represents the uniform end of year payment necessary to repay the investment in "n" years with an interest rate "i".

The formula for the capital recovery factor is:

$$CRF = \frac{i\ (1 + i)^n}{(1 + i)^n - 1}$$

where:

CPF = capital recovery factor
n = economic life of equipment
i = real interest rate

The economic life of a control system typically varies between 10 to 20 years and longer and should be determined consistent with data from EPA cost support documents and the IRS Class Life Asset Depreciation Range System.

From the example shown in Table B-12 the interest rate is 10 percent and the equipment life is 20 years. The resulting capital recovery factor is 11.75 percent. Also shown is interest on working capital, calculated as the product of interest rate and the working capital.

It is important to insure that the labor and materials costs of parts of the control system (such as catalyst beds, etc.) that must be replaced before the end of the useful life are subtracted from the total capital investment before it is multiplied by the capital recovery factor. Costs of these parts should be accounted for in the maintenance costs. To include the cost of those parts in the capital charges would be double counting. The interest rate used is a real interest rate (i.e., it does not consider inflation). The value used in most control costs analyses is 10 percent in keeping with current EPA guidelines and Office of Management and Budget recommendations for regulatory analyses.

It is also recommended that income tax considerations be excluded from cost analyses. This simplifies the analysis. Income taxes generally represent transfer payments from one segment of society to another and as such are not properly part of economic costs.

III. OTHER COST ITEMS

Lost production costs are not included in the cost estimate for a new or modified source. Other economic parameters (equipment life, cost of capital, etc.) should be consistent with estimates for other parts of the project.

APPENDIX C[7]

POTENTIAL TO EMIT

Upon commencing review of a permit application, a reviewer must define the source and then determine how much of each regulated pollutant the source potentially can emit and whether the source is major or minor (nonmajor). A new source is major if its potential to emit exceeds the appropriate major emissions threshold, and a change at an existing major source is a major modification if the source's net emissions increase is "significant." This determination not only quantifies the source's emissions but dictates the level of review and applicability of various regulations and new source review requirements. The federal regulations, 40 CFR 52.21(b)(4), 51.165(a)(1)(iii), and 51.166(b)(4), define the "potential to emit" as:

"the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable."

In the absence of federally enforceable restrictions, the potential to emit calculations should be based on uncontrolled emissions at maximum design or achievable capacity (whichever is higher) and year-round continuous operation (8760 hours per year).

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[7] This Appendix is based largely on an EPA memorandum "Guidance on Limiting Potential to Emit in New Source Permitting," from Terrell E. Hunt, Office of Enforcement and Compliance Monitoring, and John S. Seitz, Office of Air Quality Planning and Standards, June 13, 1989.

When determining the potential to emit for a source, emissions should be estimated for individual emissions units using an engineering approach. These individual values should then be summed to arrive at the potential emissions for the source. For each emissions unit, the estimate should be based on the most representative data available. Methods of estimating potential to emit may include:

- Federally enforceable operational limits, including the effect of pollution control equipment;
- performance test data on similar units;
- equipment vendor emissions data and guarantees;
- test data from EPA documents, including background information documents for new source performance standards, national emissions standards for hazardous air pollutants, and Section 111(d) standards for designated pollutants;
- AP-42 emission factors;
- emission factors from technical literature; and
- State emission inventory questionnaires for comparable sources.

NOTE: Potential to emit values reflecting the use of pollution control equipment or operational restrictions are usable only to the extent that the unit/process under review utilizes the same control equipment or operational constraints and makes them federally enforceable in the permit.

Calculated emissions will embrace all potential, not actual, emissions expected to occur from a source on a continuous or regular basis, including fugitive emissions where quantifiable. Where raw materials or fuel vary in their pollutant-generating capacity, the most pollutant-generating substance must be used in the potential-to-emit calculations unless such materials are restricted by federally enforceable operational or usage limits. Historic usage rates alone are not sufficient to establish potential-to-emit.

Permit limitations are significant in determining a source's potential to emit and, therefore, whether the source is "major" and subject to new source review. Permit limitations are the easiest and most common way for a source to restrict its potential to emit. A source considered major, based on emission calculations assuming 8760 hours per year of operation, can often be considered minor simply by accepting a federally enforceable limitation restricting hours of operation to an actual schedule of, for example, 8 hours per day. A permit does not have to be a major source permit to legally restrict potential emissions. Minor source construction permits are often federally enforceable. Any limitation can legally restrict potential to emit if it meets three criteria: 1) it is federally enforceable as defined by 40 CFR 52.21(b)(17), 52.24(f)(12), 51.165(a)(1)(xiv), and 51.166(b)(17), i.e., contained in a permit issued pursuant to an EPA-approved permitting program or a permit directly issued by EPA, or has been submitted to EPA as a revision to a State Implementation Plan and approved as such by EPA; 2) it is enforceable as a practical matter; and (3) it meets the specific criteria in the definition of "potential to emit," (i.e., any physical or operational limitation on capacity, including control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed). The second criterion is an implied requirement of the first. A requirement may purport to be federally enforceable, but in reality cannot be federally enforceable if it cannot be enforced as a practical matter.

In the absence of dissecting the legal aspects of "federal enforceability," the permit writer should always assess the enforceability of a permit restriction based upon its practicability. Compliance with any limitation must be able to be established at any given time. When drafting permit limitations, the writer must always ensure that restrictions are written in such a manner that an inspector could verify instantly whether the source is or was complying with the permit conditions. Therefore, short-term averaging times on limitations are essential. If the writer does this, he or she can feel comfortable that limitations incorporated into a permit will be federally enforceable, both legally and practically.

The types of limitations that restrict potential to emit are emission limits, production limits, and operational limits. Emissions limits should reflect operation of the control equipment, be short term, and, where feasible, the permit should require a continuous emissions monitor. Blanket emissions limits alone (e.g., tons/yr, lb/hr) are virtually impossible to verify or enforce, and are therefore not enforceable as a practical matter. Production limits restrict the amount of final product which can be manufactured or produced at a source. Operational limits include all restrictions on the manner in which a source is run, e.g., hours of operation, amount of raw material consumed, fuel combusted or stored, or specifications for the installation, maintenance and operation of add-on controls operating at a specific emission rate or efficiency. All production and operational limits except for hours of operation are limits on a source's capacity utilization. To appropriately limit potential to emit consistent with a previous Court decision [United States v. Louisiana-Pacific Corporation, 682 F. Supp. 1122 (D. Colo. Oct. 30, 1987) and 682 F. Supp. 1141 (D. Colo. March 22, 1988)], all permits issued must contain a production or operational limitation in addition to the emissions limitation and emissions averaging time in cases where the emission limitation does not reflect the maximum emissions of the source operating at full design capacity without pollution control equipment. In the permit, these limits must be stated as conditions that can be enforced independently of one another. This emphasizes the idea of good organization when drafting permit conditions and is discussed in more detail in the Part III text. The permit conditions must be clear, concise, and independent of one another such that enforceability is never questionable.

When permits contain production or operational limits, they must also have requirements that allow a permitting agency to verify a source's compliance with its limits. These additional conditions dictate enforceability and usually take the form of recordkeeping requirements. For example, permits that contain limits on hours of operation or amount of final product should require use of an operating log for recording the hours of operation and the amount of final product produced. For organizational purposes, these limitations would be listed in the permit separately and records should be kept on a frequency consistent with that of the emission limits. It should be specified that these logs be available for inspection should a permitting agency wish to check a source's compliance with the terms of its permit.

When permits require add-on controls operated at a specified efficiency level, the writer should include those operating parameters and assumptions upon which the permitting agency depended to determine that controls would achieve a given efficiency. To be enforceable, the permit must also specify that the controls be equipped with monitors and/or recorders measuring the specific parameters cited in the permit or those which ensure the efficiency of the unit as required in the permit. Only through these monitors could an inspector instantaneously measure whether a control was operating within its permit requirements and thus determine an emissions unit's compliance. It is these types of additional permit conditions that render other permit limitations practically and federally enforceable.

Every permit also should contain emissions limits, but production and operational limits are used to ensure that emissions limits expressed in the permit are not exceeded. Production limits are most appropriately expressed in the shortest time periods as possible and generally should not exceed 1 month (i.e., pounds per hour or tons per day), because compliance with emission limits is most easily established on a short term basis. An inspector, for example, could not verify compliance for an emissions unit with only monthly and annual production, operational or emission limits if the inspection occurred anytime except at the end of a month. In some rare situations a 1-month averaging time may not be reasonable. In these cases, a limit spanning a longer period is appropriate if it is a rolling average limit. However, the limit should not exceed an annual limit rolled on a monthly basis. Note also that production and operational recordkeeping requirements should be written consistent with the emissions limits. Thus, if an emissions unit was limited to a particular tons per day emissions rate, then production records which monitor compliance with this limit should be kept on a daily basis rather than weekly.

One final matter to be aware of when calculating potential to emit involves identifying "sham" permits. A sham permit is a federally enforceable permit with operating restrictions limiting a source's potential to emit such that potential emissions do not exceed the major or de minimis levels for the purpose of allowing construction to commence prior to applying for a major source permit. Permits with conditions that do not reflect a source's ***planned*** mode of operation may be considered void and cannot shield the source from the requirement to undergo major source preconstruction review. In other words, if a source accepts operational limits to obtain a minor source construction permit but intends to operate the source in excess of those limitations once the unit is built, the permit is considered a sham. If the source originally intended or planned to operate at a production level that would make it a major source, and if this can be proven, EPA will seek enforcement action and the application of BACT and other requirements of the PSD program. Additionally, a permit may be considered a sham permit if it is issued for a number of pollution-emitting modules that keep the source minor, but within a short period of time an application is submitted for additional modules which will make the total source major. The permit writer must be aware of such sham permits. If an application for a source is suspected to be a sham, EPA enforcement and source personnel should be alerted so details may be worked out in the initial review steps such that a sham permit is not issued. The possibility of sham permits emphasizes the need, as discussed in the Part III text, to organize and document the review process throughout the file. This documentation may later prove to be evidence that a sham permit was issued, or may serve to refute the notion that a source was seeking a sham permit.

Overall, the permit writer should understand the extreme importance of potential to emit calculations. It must be considered in the initial review and continually throughout the review process to ensure accurate emission limits that are consistent with federally enforceable production and operational restrictions.

United States Environmental Protection Agency

Office of Air Quality Planning and Standards
Research Triangle Park, NC 27711

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Air

EPA

Meteorological Monitoring Guidance for Regulatory Modeling Applications

EPA-454/R-99-005

Meteorological Monitoring Guidance

for Regulatory Modeling Applications

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, NC 27711

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PREFACE

This document updates the June 1987 EPA document, "On-Site Meteorological Program Guidance for Regulatory Modeling Applications", EPA-450/4-87-013. The most significant change is the replacement of Section 9 with more comprehensive guidance on remote sensing and conventional radiosonde technologies for use in upper-air meteorological monitoring; previously this section provided guidance on the use of sodar technology. The other significant change is the addition to Section 8 (Quality Assurance) of material covering data validation for upper-air meteorological measurements. These changes incorporate guidance developed during the workshop on upper-air meteorological monitoring in July 1998.

Editorial changes include the deletion of the “on-site” qualifier from the title and its selective replacement in the text with “site specific”; this provides consistency with recent changes in Appendix W to 40 CFR Part 51. In addition, Section 6 has been updated to consolidate and provide necessary context for guidance in support of air quality dispersion models which incorporate boundary layer scaling techniques.

The updated document (like the June 1987 document) provides guidance on the collection of meteorological data for use in regulatory modeling applications. It is intended to guide the EPA Regional Offices and States in reviewing proposed meteorological monitoring plans, and as the basis for advice and direction given to applicants by the Regional Offices and States. To facilitate this process, recommendations applicable to regulatory modeling applications are summarized at the end of each section. Alternate approaches, if these recommendations can not be met, should be developed on a case-by-case basis in conjunction with the Regional Office.

ACKNOWLEDGMENTS

The original (June 1987) document was prepared by the On-site Meteorological Data Work Group, formed in December 1985 and chaired by Roger Brode, EPA-OAQPS. Its members and their contributions are as follows: Edward Bennett, NY State DEC, Section 6.6; Roger Brode, EPA-OAQPS, Sections 1.0, 2.0 and 4.0; James Dicke, EPA-OAQPS, Section 5.2; Robert Eskridge, EPA-ASRL, Sections 6.2 and 6.3; Mark Garrison, EPA-Region III, Sections 3.2 and 9.0; John Irwin, EPA-ASRL, Sections 6.1 and 6.4; Michael Koerber, EPA-Region V, Sections 3.1 and 3.3; Thomas Lockhart, Meteorological Standards Institute, Section 8.0; Timothy Method, EPA-Region V, Section 3.4; Stephen Perkins, EPA-Region I, Sections 6.5 and 7.0; and Robert Wilson, EPA-Region 10, Sections 5.1 and 8.6, and parts of Sections 8.1, 8.2, and 8.5. Through their internal reviews and discussions, all of the work group members contributed to shaping the document as a whole. The work group wishes to acknowledge the time and effort of those, both within and outside of EPA, who provided technical review comments on the document. The work group also acknowledges the support and helpful guidance of Joseph A. Tikvart, EPA-OAQPS.

The June 1995 reissue of the document was prepared by Desmond T. Bailey with secretarial assistance from Ms. Brenda Cannady. Technical advice and guidance was provided by John Irwin.

The February 1999 reissue of the document provides updated material for Sections 8 (Quality Assurance) and 9 (Upper-Air Meteorological Monitoring). This material is the product of a workshop conducted at EPA facilities in Research Triangle Park, NC in July 1998. The workshop was conducted for EPA by Sharon Douglas of Systems Applications Inc. and three expert chairpersons: Ken Schere (U.S. EPA); Charles (Lin) Lindsey (Northwest Research Associates, Inc.); and Thomas Lockhart (Meteorological Standards Institute). Participants to the workshop were selected based on their expertise in atmospheric boundary layer measurements and/or the use of such data in modeling. Workshop participants were provided copies of the mock-up for review prior to the workshop, and were tasked to finalize the document during the workshop. The mock-up was prepared by Desmond Bailey (U.S. EPA) based on a draft report prepared under contract to EPA by Sonoma Technology, Inc. (SAI) entitled, "Guidance for Quality Assurance and Management of PAMS Upper-Air Meteorological Data". The latter report was written by Charles Lindsey and Timothy Dye (SAI) and Robert Baxter (Parsons Engineering Science Inc).

The two dozen participants to the workshop represented various interest groups including: remote sensing equipment vendors; local, state, and federal regulatory staff; the NOAA laboratories; university staff; and private consultants. Participants to the workshop were as follows: Desmond T. Bailey (Host), Alex Barnett (AVES), Mike Barth (NOAA Forecast Systems Lab), Bob Baxter (Parsons Engineering Science, Inc.), William B. Bendel (Radian International, LLC), Jerry Crescenti (U.S. Department of Commerce/NOAA), Sharon Douglas (Systems Applications Intl., Inc, Workshop Coordinator), Tim Dye (Sonoma Technology, Inc.), Leo Gendron (ENSR), Gerry Guay (Alaska Dept. of Environmental Conservation), Mark Huncik (CP&L), John Higuchi (SCAQMD), John Irwin (U.S. Environmental Protection Agency. Host), David Katz (Climatronics), Shawn Kendall (Phelps Dodge Corporation), Don Lehrman (T & B Systems), Charles (Lin) Lindsey (Northwest Research Associates, Inc., Chairperson), Thomas Lockhart (Meteorological Standards Institute, Chairperson), Louis Militana (Roy F. Weston, Inc), Bill B. Murphey (Georgia Dept. of Natural Resources), Kenneth L. Schere (U.S. Environmental Protection Agency ORD, Chairperson), Nelson Seaman (Pennsylvania State University), Dr. Volker Thiermann (SCINTEC Atmospharemesstechnik AG), Stan Vasa (Southern Company Services), John White (North Carolina Division of Air Quality), Dr. J. Allen Zak (NASA Langley Research Center/VIGYAN, Inc.).

Peer review of the an April 1999 draft of this document was provided by Rob Wilson (U.S. EPA, Region 10) and Larry Truppi (U.S. EPA, NERL).

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1. INTRODUCTION

1.1 Background

This document provides guidance for the collection and processing of meteorological data for general use in air quality modeling applications. Such applications include those required in support of air quality regulations as specified in the Guideline on Air Quality Models. Guidance which specifically relates to a regulatory application is so indicated; in addition, recommendations affecting regulatory modeling applications are summarized at the end of individual sections.

Guidance is provided for the in situ monitoring of primary meteorological variables (wind direction, wind speed, temperature, humidity, pressure, and radiation) for remote sensing of winds, temperature, and humidity, and for processing of derived meteorological variables such as stability, mixing height, and turbulence. Most of the guidance is generic in that it supports most categories of air quality models including: steady-state, non-steady-state, Gaussian, and non-Gaussian models. However, material in some sections is probably more useful in support of some types of models than others. For example, the primary focus of the guidance on site selection (Section 3) is the collection of data at single locations for support of steady-state modeling applications. Non-steady-state modeling applications generally require gridded meteorological data using measurements at multiple sites. Support for such applications is provided to the extent that this guidance may be used for selecting sites to monitor the significant meteorological regimes that may need to be represented in these applications. Site selection criteria in these cases must be evaluated in concert with the objectives of the overall network; this falls in the category of network design and is beyond the scope of this document. Similarity, though generically useful, the guidance on upper-air meteorological monitoring (Section 9) is perhaps most useful in support of applications employing gridded meteorological data bases.

One of the most important decisions in preparing for an air quality modeling analysis involves the selection of the meteorological data base; this is the case whether one is selecting a site for monitoring, or selecting an existing data base. These decisions almost always lead to similar questions: “Is the site (are the data) representative?” This question is addressed in Section 3.1.

Minimal guidance is provided on the use of airport data; e.g., for use in filling gaps in site-specific data bases (Section 6.8). For practical purposes, because airport data were readily available, most regulatory modeling was initially performed using these data; however, one should be aware that airport data, in general, do not meet this guidance. The significant deviations to this guidance are discussed in Section 6.7.

The following documents provide necessary background and documentation for this guidance and are incorporated by reference: "Guideline on Air Quality Models" as published in Appendix W to 40 CFR Part 51 **[1]**; "Quality Assurance Handbook for Air Pollution Measurement Systems: Volume IV. Meteorological Measurements" **[2]**; "On-site

Meteorological Instrumentation Requirements to Characterize Diffusion from Point Sources" **[3]**, "Standard for Determining Meteorological Information at Nuclear Power Sites" **[4]**.

1.2 Organization of Document

Section 2 provides general information on the instruments used for in-situ measurements of wind speed, wind direction, temperature, temperature difference, humidity, precipitation, pressure, and solar radiation. These variables are considered primary in that they are generally measured directly.

Section 3 provides guidance on siting and exposure of meteorological towers and sensors for the in-situ measurement of the primary meteorological variables. Specific guidance is provided for siting in simple terrain (Section 3.2), complex terrain (Section 3.3), coastal locations (Section 3.4), and urban locations (Section 3.5). The issue of representativeness is addressed in Section 3.1.

Section 4 provides guidance for recording of meteorological data.

Section 5 provides guidance on system performance.

Section 6 provides guidance for processing of meteorological data.

Section 7 provides guidance on data reporting and archiving.

Section 8 provides guidance on the quality assurance and quality control.

Section 9 provides guidance for the most widely used technologies employed for monitoring upper-air meteorological conditions; these include radiosondes and ground-based remote sensing platforms: sodar (Sound Detection and Ranging), radar (Radio Detection and Ranging), and RASS (Radio Acoustic Sounding System).

References are listed in Section 10.

2. PRIMARY METEOROLOGICAL VARIABLES

This section provides general information on the instruments used for in situ measurements of wind speed, wind direction, temperature, temperature difference, humidity, precipitation, pressure, and solar radiation. These variables are considered primary in that they are generally measured directly. Derived variables, such as atmospheric stability, mixing height, and turbulence are discussed in Section 6. Remote sensing platforms for measurements of winds, temperature, and humidity are discussed in Section 9; these variables, when determined using remote sensing, are not measured directly, but are derived from other measurements.

The choice of an instrument for a particular application should be guided by the data quality objectives of the application; as a minimum, these objectives should include the accuracy and resolution of the data needed by the application - recommended data quality objectives for regulatory dispersion modeling applications are provided in Section 5.0. Other considerations which may compete with the data quality objectives include the cost of the instrument, the need for and cost of routine maintenance, and the competing needs of ruggedness and sensitivity. One should also note that the cost of a successful monitoring program does not end with the purchase of the sensors; depending on the instrument, additional costs may be incurred for signal conditioning and recording hardware. There are also the costs involved in siting, installation, and calibration of the equipment, as well as costs associated with the quality assurance and processing of the data.

The focus in the following is on those classes of instruments that are considered best suited for routine in situ monitoring programs, and which generally have had the widest use. Additional information and illustrations for the instruments described in this section may be found in references **[2]**, **[5]**, **[6]**, **[7]**, and **[8]**.

2.1 Wind Speed

Although wind is a vector quantity and may be measured and processed as such, it is common to measure and/or process the scalar components of the wind vector separately; i.e., wind speed (the magnitude of the wind vector) and wind direction (the orientation of the wind vector). Wind speed determines the amount of initial dilution experienced by a plume, and appears in the denominator of the steady-state Gaussian dispersion equation (in the non-steady-state puff model, the wind speed determines the plume/puff transport). In addition, wind speed is used in the calculation of plume rise associated with point source releases, to estimate aerodynamic effects in downwash calculations, and, in conjunction with other variables, in the determination of atmospheric stability (Section 6.4.4). Instruments used for in situ monitoring of wind speed are of two types: those which employ mechanical sensors (e.g., cup and propeller anenometers) and those which employ non-mechanical sensors (hot wire anenometers and sonic anenometers). The non-mechanical sensors are beyond the scope of this guidance and are not addressed in the following; however, this should not preclude their use. When these types of instruments are to be used in support of regulatory actions, prior approval should be obtained from the reviewing authority as to how the data will be collected, processed, and quality assurred. Guidance on the use of remote sensing platforms for measuring wind speed is provided in Section 9.

2.1.1 Cup Anemometers

The rotating cup anemometer consists of three, four, and sometimes six hemispherical or cone-shaped cups mounted symmetrically about a vertical axis of rotation. The three cup anemometer is recommended; this design has been shown to exert a more uniform torque throughout a revolution. The rate of rotation of the cups is essentially linear over the normal range of measurements, with the linear wind speed being about 2 to 3 times the linear speed of a point on the center of a cup, depending on the dimensions of the cup assembly and the materials from which the sensor is made **[5]**. Sensors with high accuracy at low wind speeds and a low starting threshold should be used (see Section 5). Light weight materials (e.g., molded plastic or polystyrene foam) should be employed to achieve a starting threshold (lowest speed at which a rotating anemometer starts and continues to turn when mounted in its normal position) of $\leq$ 0.5 m/s.

2.1.2 Vane-oriented and Fixed-mount Propeller Anemometers

The vane-oriented propeller anemometer usually consists of a two, three or four-balded propeller which rotates on a horizontal pivoted shaft that is turned into the wind by a vane. Most current versions of this type of anemometer use propellers that are based on a modified helicoid. The dynamic characteristics of the vane should be matched with those of the propeller.

There are several propeller anemometers which employ lightweight molded plastic or polystyrene foam for the propeller blades to achieve threshold speeds of $\leq$ 0.5 m/s. This type of anemometer may be applied to collecting mean wind speeds for input to models to determine dilution estimates and/or transport estimates. Because of their relatively quick response times, some having distance constants of about one meter, these sensors are also suitable for use in determining the standard deviation of the along-wind-speed fluctuations, σ_u. Care should be taken, however, in selecting a sensor that will provide an optimal combination of such characteristics as durability and sensitivity for the particular application.

The variation of output speed with the approach angle of the wind follows nearly a cosine response for some helicoid propeller anemometers. This relationship permits the use of two orthogonal fixed-mount propellers to determine the vector components of the horizontal wind. A third propeller with a fixed mount rotating about a vertical axis may be used to determine the vertical component of the wind, and also the standard deviation of the vertical wind, σ_w. It should be noted that deviation of the response from a true cosine for large approach angles (e.g., 80-90°) may lead to underestimations of the vertical wind component without special calibration of the output signal. Users of vertical propeller anemometers should consult with the manufacturer on proper handling of the data.

2.1.3 Wind Speed Transducers

There are several mechanisms that can be used to convert the rate of the cup or propeller rotations to an electrical signal suitable for recording and/or processing. The four most commonly used types of transducers are the DC generator, the AC generator, the electrical-contact, and the interrupted light beam. Many DC and AC generator types of transducers in common use have limitations in terms of achieving low thresholds and quick response times. Some DC generator transducers are limited because the combined effect of brush and bearing friction give a threshold speed above 0.5 m/s (above 1.0 mph). However, some anemometers employ miniaturized DC generators which allow thresholds below 0.5 m/s to be achieved. The AC generator transducers eliminate the brush friction, but care must be exercised in the design of the signal conditioning circuitry to avoid spurious oscillations in the output signal that may be produced at low wind speeds. Electrical-contact transducers are used to measure the "run-of-the-wind"; i.e., the amount of air (measured as a distance) passing a fixed point in a given time interval; wind speed is calculated by dividing run-of-the-wind measurements by the time interval. The interrupted light beam (light chopping) transducer is frequently used in air quality applications because of the lower threshold that can be achieved by the reduction in friction. This type of transducer uses either a slotted shaft or a slotted disk, a photo emitter and a photo detector. The cup or propeller assembly rotates the slotted shaft or disk, creating a pulse each time the light passes through a slot and falls on the photo detector. The frequency output from this type of transducer is handled in the same way as the output from an AC generator. Increasing the number of slots to about 100, thereby increasing the pulse rate, eliminates signal conditioning problems which may arise with lower frequencies. The frequency output from an AC generator or a light chopping transducer may be transmitted through a signal conditioner and converted to an analog signal for various recording devices, such as a continuous strip chart or a multi point recorder, or through an analog-to-digital (A/D) converter to a microprocessor type of digital recorder. Several modern data loggers can accept the frequency type signal directly, eliminating the need for additional signal conditioning. The recording and processing of the data are covered in more detail in Sections 4.0 and 6.0, respectively.

2.2 Wind Direction

Wind direction is generally defined as the orientation of the wind vector in the horizontal. Wind direction for meteorological purposes is defined as the direction <u>from</u> which the wind is blowing, and is measured in degrees clockwise from true north. Wind direction determines the transport direction of a plume or puff in air quality modeling applications. The standard deviation of the wind direction, σ_A, or the standard deviation of the elevation angle, σ_E, may also be used, in conjunction with wind speed, to derive the atmospheric stability category (Section 6.4). Wind direction may be measured directly using a wind vane (Section 2.2.1) or may be derived from measurements of wind speed components (Section 2.2.2).

2.2.1 Wind Vanes

The conventional wind vane consists of a tail section attached to one end of a horizontal shaft which, in turn, is mounted on a vertical axis; the tail and shaft rotate in a horizonal plane. The wind vane measures the azimuth angle of the wind. Wind vanes and tail fins should be constructed from light weight materials. The starting threshold (lowest speed at which a vane will turn to within 5^o of the true wind direction from an initial displacement of 10^o) should be ≤ 0.5 ms^{-1}. Overshoot must be ≤ 25% and the damping ratio should lie between 0.4 and 0.7.

Bi-directional vanes (bivanes) measure both the azimuth and elevation angles of the wind vector. The bivane generally consists of either an annular fin or two flat fins perpendicular to each other, counterbalanced and mounted on a gimbal so that the unit can rotate freely both horizontally and vertically. Bivanes require greater care and are not generally suited for routine monitoring. Data from bivanes, consequently, should only be used on a case by case basis with the approval of the reviewing authority.

2.2.2 U-V and UVW Systems

Another method of obtaining the horizontal and/or vertical wind direction is through the use of orthogonal fixed-mount propeller anemometers, the U-V or UVW systems. The horizontal and, in the case of UVW systems, the vertical, wind direction can be determined computationally from the orthogonal wind speed components. The computational methods are based on the fact that the variation of output speed with the approach angle of the wind follows nearly a cosine response for some helicoid propeller anemometers.

2.2.3 Wind Direction Transducers

Many kinds of simple commutator type transducers utilize brush contacts to divide the wind direction into eight or 16 compass point sectors. However, these transducers do not provide adequate resolution to characterize transport for most air quality modeling applications.

A fairly common transducer for air quality modeling applications is a 360° potentiometer. The voltage across the potentiometer varies directly with the wind direction. A commonly used solution to the discontinuity that occurs across the small gap in a single potentiometer is to place a second potentiometer 180° out of phase with the first one **[5]**. In this case the voltage output corresponds to a 0° to 540° scale. This transducer utilizes a voltage discriminator to switch between the "upper" and "lower" potentiometers at appropriate places on the scale. This technique eliminates chart "painting" which occurs on strip chart recorders when the wind oscillates across north (i.e., between 0 and full scale). A disadvantage is that chart resolution is reduced by one third.

Another type of transducer being used is a wind direction resolver, which is a variable phase transformer where the phase change is a function of the shaft rotation angle. This system alleviates the maintenance problems associated with the friction caused by the wiper in a potentiometer; however, this type of transducer is more expensive and requires more complex signal conditioning circuity.

2.2.4 Standard Deviation and Turbulence Data

The standard deviation of the azimuth and elevation angles of the wind vector, σ_A and σ_E, respectively can be related to the dispersive capabilities of the atmosphere, in particular, to the dispersion coefficients σ_y and σ_z which characterize plume concentration distributions in commonly-used Gaussian models. These quantities can be used as inputs to algorithms to determine Pasquill stability categories (see Section 6.4.4), or may also be treated as turbulence data for direct input to certain Gaussian models. The σ values should be computed directly from high-speed analog or digital data records (Section 6.1). If a sigma meter or sigma computer is used, care should be taken that the results are not biased by smoothing of the data, and to ensure that the methods employed accurately treat the 0-360° crossover and use an adequate number of samples (at least 360 per averaging period, see Section 6.1.4). The comparability of results from the sigma computer to the direct statistical approach should be demonstrated. To accurately determine σ_A and σ_E, the wind direction sensors must possess certain minimum response characteristics. The most important in this regard is the damping ratio, which should be between 0.4 to 0.7 (see Section 5.2). The wind direction should also be recorded to a resolution of 1 degree in order to calculate the standard deviation.

2.3 Temperature and Temperature Difference

This section addresses both the measurement of ambient air temperature at a single level and the measurement of the temperature difference between two levels. The ambient temperature is used in determining the amount of rise experienced by a buoyant plume. The vertical temperature difference is used in calculating plume rise under stable atmospheric conditions, and is also used in determining Monin-Obukhov length, a stability parameter (Section 6.4.5).

2.3.1 Classes of Temperature Sensors

Sensors used for monitoring ambient temperature include: wire bobbins, thermocouples, and thermistors. Platinum resistance temperature detectors (RTD) are among the more popular sensors used in ambient monitoring; these sensors provide accurate measurements and maintain a stable calibration over a wide temperature range. The RTD operates on the basis of the resistance changes of certain metals, usually platinum or copper, as a function of temperature. These two metals are the most commonly used because they show a fairly linear increase of resistance with rising temperature **[5]**. "Three wire" and "four wire" RTDs are commonly used to compensate for lead resistance errors. A second type of resistance change thermometer is the thermistor, which is made from a mixture of metallic oxides fused together. The thermistor generally gives a larger resistance change with temperature than the RTD. Because the relation between resistance and temperature for a thermistor is non-linear, systems generally are designed to use a combination of two or more thermistors and fixed resistors to produce a nearly linear response over a specific temperature range **[5, 8]**.

Thermoelectric sensors work on the principle of a temperature dependent electrical current flow between two dissimilar metals. Such sensors, called thermocouples, have some special handling requirements for installation in order to avoid induction currents from nearby AC sources, which can cause errors in measurement **[5]**. Thermocouples are also susceptible to spurious voltages caused by moisture. For these reasons, their usefulness for routine field measurements is limited.

2.3.2 Response Characteristics

The response of temperature sensors can be characterized by a first order linear differential equation. The time constant for temperature sensors, i.e. the time taken to respond to 63% of a step change in the temperature, is a function of the air density and wind speed or ventilation rate. The time constant for a mercury-in-glass thermometer is about l minute for a ventilation rate of 5 m/s **[5, 6]**. Time constants for platinum resistance temperature detectors (RTDs) and for thermistors mounted in a typical probe are about 45 seconds. These are adequate response times for monitoring programs (see Section 5.2).

2.3.3 Temperature Difference

The basic sensor requirements for measuring vertical temperature difference are essentially the same as for a simple ambient temperature measurement. However, matched sensors and careful calibration are required to achieve the desired accuracy of measurement. The ambient temperature measurement is often taken from one of the sensors used to measure the differential temperature. A number of systems are commercially available that utilize a special translator module to process the signal difference between the two component sensors. Through signal processing, the accuracy of the differential temperature can be calibrated to the level of resolution of the component systems.

2.3.4 Sources of Error

One of the largest sources of error in any temperature system is due to solar radiation. Temperature sensors must be adequately shielded from the influences of direct or reflected solar radiation in order to provide representative measurements. A well ventilated shelter may be adequate for surface temperature measurements but would be impractical for levels higher than a few meters above ground. Tower-mounted sensors are generally housed in aspirated radiation shields. It is advisable to utilize motor driven aspirators to ensure adequate ventilation. Care should also be taken that moisture not be allowed to come in contact with the sensor or the inside surfaces of the radiation shield. In some sensors moisture will change the electrical properties of the sensor, causing error. In others, the evaporative cooling will cause the temperature reading to be too low. For temperature difference measurements, sensors should be housed in identical aspirated radiation shields with equal exposures.

2.4 Humidity

2.4.1 Humidity Variables

Humidity is a general term related to the amount of moisture in the air; humidity variables include vapor pressure, dew point temperature, specific humidity, absolute humidity, and relative humidity. With the exception of relative humidity, all of the above variables provide a complete specification of the amount of water vapor in the air; in the case of relative humidity, measurements of temperature and pressure are also required. Humidity is an important variable in determining impacts from moist sources, such as cooling towers; it is also used in modeling ozone chemistry.

2.4.2 Types of Instrumentation

There are basically two types of sensors for measuring humidity, psychrometers and hygrometers. The psychrometer, consists of two thermometers, one of which is covered with a wet wick (the wet bulb) and a mechanism for ventilating the pair. Evaporation lowers the temperature of the wet bulb; the difference in temperature from the dry bulb (the wet bulb depression) is a measure of the amount of moisture in the air. While still in use at many observing stations, psychrometers are generally not suitable for routine monitoring programs. However, they can be used as secondary standards in audit procedures.

Hygrometers are a class of instruments that measure the physical effect that moisture has on a substances, such as hair. For example, the lithium chloride hygrometer uses a probe impregnated with lithium chloride solution. Voltage is supplied to the electrodes in the probe until an equilibrium temperature is reached based on the conductivity of the lithium chloride. The dew point hygrometer, uses a cooled mirror as a sensor; in this case, the temperature of the mirror is monitored to determine the temperature at which dew (or frost) first appears. Such condensation typically disrupts the path of a light beam reflecting off of the cooled surface, causing it to be heated until the condensation disappears. Once the condensation is gone, the surface is cooled again until condensation forms. These oscillating heating and cooling cycles define an average dew point temperature. The temperature of the surface is typically measured by a linear thermistor or a platinum RTD. The thin film capacitor hygrometer measures humidity by detecting the change in capacitance of a thin polymer film; this sensor has a relatively fast response compared to other types of hygrometers.

If possible, humidity sensors should be housed in the same aspirated radiation shield as the temperature sensor. The humidity sensor should be protected from contaminants such as salt, hydrocarbons, and other particulates. The best protection is the use of a porous membrane filter which allows the passage of ambient air and water vapor while keeping out particulate matter.

2.5 Precipitation

Precipitation data, although primarily used in wet deposition modeling, are also used for consistency checks in data review and validation. The two main classes of precipitation measuring devices suitable for meteorological programs are the tipping bucket rain gauge and the weighing rain gauge. Both types of gauge measure total liquid precipitation. Both types of gauge may also be used to measure the precipitation rate, but the tipping bucket is preferable for that application. A third type, the optical rain gauge, has not yet been adequately developed for widespread use.

The tipping bucket rain gauge is probably the most common type of instrument in use for meteorological programs. The rainfall is collected by a cylinder, usually about 8 to 12 inches in diameter, and funneled to one of two small "buckets" on a fulcrum. Each bucket is designed to collect the equivalent of 0.01 inches (0.3 mm) of precipitation, then tip to empty its contents and bring the other bucket into position under the funnel. Each tip of the bucket closes an electrical contact which sends a signal to a signal conditioner for analog and/or digital recording. These are fairly reliable and accurate instruments. Measurement errors may occur if the funnel is too close to the top of the cylinder, resulting in an underestimate of precipitation due to water splashing out of the cylinder, especially during heavy rainfall. Underestimates may also occur during heavy rainfall because precipitation is lost during the tipping action. Inaccuracies may also result if the tipping bucket assembly or the entire gauge is not leveled properly when installed. Tipping buckets are generally equipped with heaters to melt the snow in cold climates, however, the total precipitation may be underestimated due to evaporation of the frozen precipitation caused by the heating element. It would be preferable for the heater to be thermostatically controlled, rather than operate continuously, to avoid underestimation due to evaporation that may also occur during periods of light rain or drizzle. Underestimation of precipitation, especially snowfall, may also result from cases where the gauge is not adequately sheltered from the influence of the wind. A wind shield should therefore be used in climates that experience snowfall. Strong winds can also cause the buckets to tip, resulting in spurious readings.

The weighing rain gauge has the advantage that all forms of precipitation are weighed and recorded as soon as they fall into the gauge. No heater is needed to melt the snow, except to prevent snow and ice buildup on the rim of the gauge, alleviating the problem of evaporation of snow found with the heated tipping bucket gauge. Antifreeze is often used to melt the snow in the bucket. However, the weighing gauge requires more frequent tending than the tipping bucket gauge, and is more sensitive to strong winds causing spurious readings. The weight of precipitation is recorded on a chart mounted on a clock-driven drum for later data reduction. Weighing systems are also available which provide an electrical signal for digital processing.

2.6 Pressure

Atmospheric or barometric pressure can provide information to the meteorologist responsible for reviewing data that may be useful in evaluating data trends, and is also used in conjunction with air quality measurements. There are two basic types of instruments available for measuring atmospheric pressure, the mercury barometer and the aneroid barometer.

The mercury barometer measures the height of a column of mercury that is supported by the atmospheric pressure. It is a standard instrument for many climatological observation stations, but it does not afford automated data recording.

Another common type of pressure instrument is the aneroid barometer which consists of two circular disks bounding an evacuated volume. As the pressure changes, the disks flex, changing their relative spacing which is sensed by a mechanical or electrical element and transmitted to a transducer. A barograph is usually an aneroid barometer whose transducer is a mechanical linkage between the bellows assembly and an ink pen providing a trace on a rotating drum. A more sophisticated aneroid barometer providing a digital output has been developed consisting of a ceramic plate substrate sealed between two diaphragms. Metallic areas on the ceramic substrate form one plate of a capacitor, with the other plate formed by the two diaphragms. The capacitance between the internal electrode and the diaphragms increases linearly with applied pressure. The output from this barometer is an electronic signal that can be processed and stored digitally **[5]**.

2.7 Radiation

Solar and/or net radiation data are used to determine atmospheric stability (Section 6.4.2), for calculating various surface-layer parameters used in dispersion modeling (Section 6.6), for estimating convective (daytime) mixing heights, and for modeling photochemical reactions.

Solar radiation refers to the electromagnetic energy in the solar spectrum (0.10 to 4.0 μm wavelength); the latter is commonly classified as ultraviolet (0.10 to 0.40 μm), visible light (0.40 to 0.73 μm), and near-infrared (0.73 to 4.0 μm) radiation. Net radiation includes both solar radiation (also referred to as short-wave radiation) and terrestrial or long-wave radiation; the sign of the net radiation indicates the direction of the flux (a negative value indicates a net upward flux of energy).

Pyranometers are a class of instruments used for measuring energy fluxes in the solar spectrum. These instruments are configured to measure what is referred to as global solar radiation; i.e., direct plus diffuse (scattered) solar radiation incidence on a horizontal surface. The sensing element of the typical pyranometer is protected by a clear glass dome which both protects the sensing element, and functions as a filter preventing entry of energy outside the solar spectrum (i.e., long-wave radiation). The glass domes used on typical pyranometers are transparent to wavelengths in the range of 0.28 to 2.8 μm. Filters can be used instead of the clear glass dome to measure radiation in different spectral intervals; e.g., ultraviolet radiation.

WMO specifications for several classes of pyranometers are given in Table 2-1 **[9]**. First class and secondary standard pyranometers typically employ a thermopile for the sensing element. The thermopile consists of a series of thermojunction pairs, an optically black primary junction, and an optically white reference junction (in some pyranometers, the reference thermojunction is embedded in the body of the instrument). The temperature difference between the primary and reference junctions which results when the pyranometer is operating generates an electrical potential proportional to the solar radiation. Second class pyranometers typically employ photo-cells for the sensing element. Though less costly than other types of pyranometers, the spectral response of the photovoltaic pyranometer is limited to the visible spectrum.

First class or second class pyranometers should normally be used for measuring global solar radiation, depending on the application. If the solar radiation data are to be used in procedures for estimating stability (Section 6.4) then second class (photovoltaic) pyranometers are acceptable. For most other applications, first class or secondary standard pyranometers should be used. Applications requiring ultraviolet (UV) radiation data should not employ photovoltaic measurements as these instruments are not sensitive to UV radiation.

Table 2-1

Classification of Pyranometers [9]

Characteristic	Units	Secondary Standard	First Class	Second Class
Resolution	W m^{-2}	±1	±5	±10
Stability	%FS*	±1	±2	±5
Cosine Response	%	< ±3	< ±7	< ±15
Azimuth Response	%	< ±3	< ±5	< ±10
Temperature Response	%	±1	±2	±5
Nonlinearity	%FS*	±0.5	±2	±5
Spectral Sensitivity	%	±2	±5	±10
Response Time (99%)	seconds	< 25	< 60	< 240

* Percent of full scale

2.8 Recommendations

Light weight three cup anemometers (Section 2.1.1) or propeller anemometers (Section 2.1.2) should be used for measuring wind speed. Sensors with high accuracy at low wind speeds and a low starting threshold should be used (see Section 5). Light weight, low friction systems which meet the performance specifications given in Section 5.0 should be used. Heaters should be employed to protect against icing in cold climates. Sonic anenometers and hot wire *anenometers may be used with the approval of the reviewing authority. These instruments are especially suited for use in direct measurements of turbulence.*

Wind direction should be measured directly using a wind vane (Section 2.2.1) or may be derived from measurements of wind speed components (Section 2.2.2). Light weight, low friction systems which meet the performance specifications given in Section 5.0 should be used. Heaters should be employed to protect against icing in cold climates. Bivanes are regarded as research grade instruments and are not generally suited for routine monitoring. Data from bivanes may be used on a case by case basis with the approval of the reviewing authority.

Temperature and temperature difference should be measured using resistance temperature devices which meet the performance specifications of Section 5.0. Thermoelectric sensors (thermocouples) are not recommended because of their limited accuracy and complex circuitry.

Humidity should be measured using a dew point, lithium chloride, or thin-film capacitor hygrometer. The hygrometer should meets the performance specifications in Section 5.0.

Precipitation should be measured with a weighing or tipping bucket rain gauge. In cold climates, the gauge should be equipped with a heater and a wind shield.

Atmospheric pressure should be measured with an aneroid barometer which meets the performance specifications given in Section 5.0

First class or second class pyranometers should normally be used for measuring global solar radiation, depending on the application. If the solar radiation data are to be used in procedures for estimating stability (Section 6.4) then second class (photovoltaic) pyranometers are acceptable. For most other applications, first class or secondary standard pyranometers should be used. Applications requiring ultraviolet (UV) radiation data should not employ photovoltaic measurements as these instruments are not sensitive to UV radiation.

Recommended performance specifications for the primary meteorological variables are provided in Table 5-1.

3. SITING AND EXPOSURE

This section provides guidance on siting and exposure of meteorological towers and sensors for the in situ measurement of the primary meteorological variables. Specific guidance is provided for siting in simple terrain (Section 3.2), in complex terrain (Section 3.3), in coastal locations (Section 3.4), and in urban locations (Section 3.5). The issue of representativness is addressed in Section 3.1.

As a general rule, meteorological sensors should be sited at a distance which is beyond the influence of obstructions such as buildings and trees; this distance depends upon the variable being measured as well as the type of obstruction. The other general rule is that the measurements should be representative of meteorological conditions in the area of interest; the latter depends on the application. Secondary considerations such as accessibility and security must be taken into account, but should not be allowed to compromise the quality of the data. In addition to routine quality assurance activities (see Section 8), annual site inspections should be made to verify the siting and exposure of the sensors. Approval for a particular site selection should be obtained from the permit granting agency prior to any site preparation activities or installation of any equipment.

3.1 Representativeness

One of the most important decisions in preparing for an air quality modeling analysis involves the selection of the meteorological data base; this is the case whether one is selecting a site for monitoring, or selecting an existing data base. These decisions almost always lead to similar questions: “Is the site (are the data) representative?” Examples eliciting a negative response abound; e.g., meteorological data collected at a coastal location affected by a land/sea breeze circulation would generally not be appropriate for modeling air quality at an inland site located beyond the penetration of the sea breeze. One would hope that such examples could be used in formulating objective criteria for use in evaluating representativeness in general. Though this remains a possibility, it is not a straight forward task - this is due in part to the fact that representativeness is an exact condition; a meteorological observation, data base, or monitoring site, either is, or is not representative within the context of whatever criteria are prescribed. It follows that, a quantitative method does not exist for determining representativeness absolutely. Given the above, it should not be surprising that there are no generally accepted analytical or statistical techniques to determine representativeness of meteorological data or monitoring sites.

3.1.1 Objectives for Siting

Representativeness has been defined as "the extent to which a set of measurements taken in a space-time domain reflects the actual conditions in the same or different space-time domain taken on a scale appropriate for a specific application" **[10]**. The space-time and application aspects of the definition as relates to site selection are discussed in the following.

In general, for use in air quality modeling applications, meteorological data should be representative of conditions affecting the transport and dispersion of pollutants in the “area of interest” as determined by the locations of the sources and receptors being modeled. In many instances, e.g. in complex terrain, multiple monitoring sites may be required to adequately represent spatial variations in meteorological conditions affecting transport and/or dispersion.

In steady-state modeling applications, one typically focuses on the meteorological conditions at the release height of the source or sources, or the plume height in the case of buoyant sources. Representativeness for steady-state modeling applications must necessarily be assessed in concert with the steady-state assumption that meteorological conditions are constant within the space-time domain of the application; as typically applied, measurements for a single location, somewhere near the source, are assumed to apply, without change, at all points in the modeling domain. Consistency would call for site selection criteria consistent with the steady-state assumption; i.e., to the extent possible, sites should perhaps be selected such that factors which cause spatial variations in meteorological conditions, are invariant over the spatial domain of the application, whatever that might be. Such factors would include surface characteristics such as ground cover, surface roughness, the presence or absence of water bodies, etc. Similarly, the representativeness of existing third-party data bases should be judged, in part, by comparing the surface characteristics in the vicinity of the meteorological monitoring site with the surface characteristics that generally describe the analysis domain.

Representativeness has an entirely different interpretation for non-steady-state modeling applications which commonly employ three dimensional gridded meteorological fields based on measurements at multiple sites. The meteorological processors which support these applications are designed to appropriately blend available NWS data, local site-specific data, and prognostic mesoscale data; empirical relationships are then used to diagnostically adjust the wind fields for mesoscale and local-scale effects **[11]**, **[12]** . These diagnostic adjustments can be improved through the use of strategically placed site-specific meteorological observations. Support for such applications is provided to the extent that this guidance can be used for selecting sites to monitor the significant meteorological regimes that may need to be represented in these applications. Site selection for such applications (often more than one location is needed) falls in the category of network design and is beyond the scope of this document. Model user’s guides should be consulted for meteorological data requirements and guidance on network design for these applications.

3.1.2 Factors to Consider

Issues of representativeness will always involve case-by-case subjective judgements; consequently, experts knowledgeable in meteorological monitoring and air quality modeling should be included in the site selection process. The following information is provided for consideration in such decisions. Readers are referred to a 1982 workshop report **[10]** on representativeness for further information on this topic.

- It is important to recognize that, although certain meteorological variables may be considered unrepresentative of another site (for instance, wind direction or wind speed), other variables may be representative (such as temperature, dew point, cloud cover). Exclusion of one variable does not necessarily exclude all. For instance, one can argue that weather observations made at different locations are likely to be similar if the observers at each location are within sight of one another - a stronger argument can be made for some types of observations (e.g., cloud cover) than others. Although, by no means a sufficient condition, the fact that two observers can "see" one another supports a conclusion that they would observe similar weather conditions.
- In general, the representativeness of the meteorological data used in an air quality modeling analysis is dependent on the proximity of the meteorological monitoring site to the "area-of-interest".
- Spatial representativeness of the data will almost always be adversely affected (degraded) by increasing the distance between the sources and receptors (increasing the size of the area-of-interest).
- Although proximity of the meteorological monitoring site is an important factor, representativeness is not simply a function of distance. In some instances, even though meteorological data are acquired at the location of the pollutant source, they may not correctly characterize the important atmospheric dispersion conditions; e.g., dispersion conditions affecting sources located on the coast are strongly affected by off-shore air/sea boundary conditions - data collected at the source would not always reflect these conditions.
- Representativeness is a function of the height of the measurement. For example, one can expect more site-to-site variability in measurements taken close to the surface compared to measurements taken aloft. As a consequence, upper-air measurements are generally representative of much larger spatial domains then are surface measurements.
- Where appropriate, data representativeness should be viewed in terms of the appropriateness of the data for constructing realistic boundary layer profiles and three dimensional meteorological fields.
- Factors that should be considered in selecting a monitoring site in complex terrain include: the aspect ratio and slope of the terrain, the ratios of terrain height to stack height and plume height, the distance of the source from the terrain feature, and the effects of terrain features on meteorological conditions, especially wind speed and wind direction.

3.2 Simple Terrain Locations

For the purposes of this guidance, the term "simple terrain" is intended to mean any site where terrain effects on meteorological measurements are non-significant. The definition of significance depends on the application; for regulatory dispersion modeling applications, significance is determined by comparing stack-top height to terrain height - terrain which is below stack-top is classified as simple terrain **[1]**

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3.2.1 Wind Speed and Wind Direction

3.2.1.1 Probe placement

The standard exposure height of wind instruments over level, open terrain is 10 m above the ground **[9]**. Open terrain is defined as an area where the distance between the instrument and any obstruction is at least ten times the height of that obstruction **[2, 4, 9]**. The slope of the terrain in the vicinity of the site should be taken into account when determining the relative height of the obstruction **[2]**. An obstruction may be man-made (such as a building or stack) or natural (such as a hill or a tree). The sensor height, its height above obstructions, and the height/character of nearby obstructions should be documented. Where such an exposure cannot be obtained, the anemometer should be installed at such a height that it is reasonably unaffected by local obstructions and represents the approximate wind values that would occur at 10 m in the absence of the obstructions. This height, which depends on the extent, height, and distance of obstructions and on site availability, should be determined on a case-by-case basis. Additional guidance on the evaluation of vertical profiles (Section 6.1.3) and surface roughness (Section 6.4.2) may be helpful in determining the appropriate height.

If the source emission point is substantially above 10 m, then additional wind measurements should be made at stack top or 100 m, whichever is lower **[1]**. In cases with stack heights of 200 m or above, the appropriate measurement height should be determined by the Regional Office on a case-by-case basis. Because maximum practical tower heights are on the order of 100 m, wind data at heights greater than 100 m will most likely be determined by some other means. Elevated wind measurements can be obtained via remote sensing (see Section 9.0). Indirect values can be estimated by using a logarithmic wind-speed profile relationship. For this purpose, instruments should be located at multiple heights (at least three) so that site-specific wind profiles can be developed.

3.2.1.2 Obstructions

Buildings. Aerodynamic effects due to buildings and other major structures, such as cooling towers, should be avoided to the extent possible in the siting of wind sensors; such effects are significant, not only in the vicinity of the structures themselves, but at considerable distances downwind. Procedures for assessing aerodynamic effects have been developed from observing such effects in wind tunnels **[13]**, **[14]**. Wind sensors should only be located on building rooftops as a last resort; in such cases, the sensors should be located at a sufficient height above the rooftop to avoid the aerodynamic wake. This height can be determined from on-site measurements (e.g., smoke releases) or wind tunnel studies. As a rule of thumb, the total depth of the building wake is estimated to be approximately 2.5 times the height of the building **[1]**.

<u>Trees</u>. In addition to the general rules concerning obstructions noted above, additional considerations may be important for vegetative features (e.g., growth rates). Seasonal effects should also be considered for sites near deciduous trees. For dense, continuous forests where an open exposure cannot be obtained, measurements should be taken at 10m above the height of the general vegetative canopy.

<u>Towers</u>. Sensors mounted on towers are frequently used to collect wind speed measurements at more than one height. To avoid the influence of the structure itself, closed towers, stacks, cooling towers, and similar solid structures should not be used to support wind instruments. Open-lattice towers are preferred. Towers should be located at or close to plant elevation in an open area representative of the area of interest.

Wind instruments should be mounted on booms at a distance of at least twice the diameter/diagonal of the tower (from the nearest point on the tower) into the prevailing wind direction or wind direction of interest **[2]**. Where the wind distribution is strongly bimodal from opposite directions, such as in the case of up-valley and down-valley flows, then the booms should be at right angles to the predominant wind directions. The booms must be strong enough so that they will not sway or vibrate sufficiently to influence standard deviation values in strong winds. Folding or collapsible towers are not recommended since they may not provide sufficient support to prevent such vibrations, and also may not be rigid enough to ensure proper instrument orientation. The wind sensors should be located at heights of minimum tower density (i.e., minimum number of diagonal cross-members) and above/below horizontal cross-members **[2]**. Since practical considerations may limit the maximum boom length, wind sensors on large towers (e.g., TV towers and fire look-out towers) may only provide accurate measurements over a certain arc. In such cases, two systems on opposite sides of the tower may be needed to provide accurate measurements over the entire 360°. If such a dual system is used, the method of switching from one system to the other should be carefully specified. A wind instrument mounted on top of a tower should be mounted at least one tower diameter/diagonal above the top of the tower structure.

<u>Surface roughness</u>. The surface roughness over a given area reflects man-made and natural obstructions, and general surface features. These roughness elements effect the horizontal and vertical wind patterns. Differences in the surface roughness over the area of interest can create differences in the wind pattern that may necessitate additional measurement sites. A method of estimating surface roughness length, z_o, is presented in Section 6.4.2. If an area has a surface roughness length greater than 0.5 m, then there may be a need for special siting considerations (see discussion in Sections 3.3 and 3.5).

3.2.1.3 Siting considerations

A single well-located measurement site can be used to provide representative wind measurements for non-coastal, flat terrain, rural situations. Wind instruments should be placed taking into account the purpose of the measurements. The instruments should be located over level, open terrain at a height of 10 m above the ground, and at a distance of at least ten times the height of any nearby obstruction. For elevated releases, additional measurements should be made at stack top or 100 m, whichever is lower **[1]**. In cases with stack heights of 200 m or above, the appropriate measurement height should be determined by the Regional Office on a case-by-case basis.

3.2.2 Temperature, Temperature Difference, and Humidity

The siting and exposure criteria for temperature, temperature difference and humidity are similar. Consequently, these variables are discussed as a group in the following; exceptions are noted as necessary.

3.2.2.1 Probe placement

Ambient temperature and humidity should be measured at 2 m, consistent with the World Meteorological Organization (WMO) standards for ambient measurements **[9]**. Probe placement for temperature difference measurements depend on the application.. For use in estimating surface layer scaling parameters (Section 6.6.4), the temperature difference should be measured between $20z_0$ and $100z_0$; the same recommendation applies to temperature difference measurements for use in estimating the P-G stability category using the solar radiation delta-T method (Section 6.4.4.2). For use in estimating stable plume rise, temperature difference measurements should be made across the plume rise layer, a minimum separation of 50 m is recommended. For sites that experience large amounts of snow, adjustments to the temperature measurement height may be necessary, however, the ambient temperature measurement should not extend above 10 m. For analysis of cooling tower impacts, measurements of temperature and humidity should also be obtained at source height and within the range of final plume height. The measurement of temperature difference for analysis of critical dividing streamline height, H_{crit}, a parameter used in complex terrain modeling, is discussed in Section 3.3.3.

Temperature and humidity sensors should be located over an open, level area at least 9 m in diameter. The surface should be covered by short grass, or, where grass does not grow, the natural earth surface **[2, 9]**. Instruments should be protected from thermal radiation (from the earth, sun, sky, and any surrounding objects) and adequately ventilated using aspirated shields. Forced aspiration velocity should exceed 3 m/s, except for lithium chloride dew cells which operate best in still air **[2]**. If louvered shelters are used instead for protection (at ground level only), then they should be oriented with the door facing north (in the Northern Hemisphere). Temperature and humidity data obtained from naturally-ventilated shelters will be subject to large errors when wind speeds are light (less than about 3 m/s).

Temperature and humidity sensors on towers should be mounted on booms at a distance of about one diameter/diagonal of the tower (from the nearest point on the tower) **[2]**. In this case, downward facing aspiration shields are necessary.

3.2.2.2 Obstructions

Temperature and humidity sensors should be located at a distance of at least four times the height of any nearby obstruction and at least 30 m from large paved areas **[2]**, **[15]**. Other situations to avoid include: large industrial heat sources, rooftops, steep slopes, sheltered hollows, high vegetation, shaded areas, swamps, areas where frequent snow drifts occur, low places that hold standing water after rains, and the vicinity of air exhausts (e.g., from a tunnel or subway) **[2, 9]**.

3.2.2.3 Siting considerations

In siting temperature sensors, care must be taken to preserve the characteristics of the local environment, especially the surface. Protection from thermal radiation (with aspirated radiation shields) and significant heat sources and sinks is critical. Siting recommendations are similar for humidity measurements, which may be used for modeling input in situations involving moist releases, such as cooling towers. For temperature difference measurements, sensors should be housed in identical aspirated radiation shields with equal exposure.

3.2.3 Precipitation

3.2.3.1 Probe placement

A rain gauge should be sited on level ground so the mouth is horizontal and open to the sky **[2]**. The underlying surface should be covered with short grass or gravel. The height of the opening should be as low as possible (minimum: 30 cm), but should be high enough to avoid splashing in from the ground.

Rain gauges mounted on towers should be located above the average level of snow accumulation **[15]**. In addition, collectors should be heated if necessary to properly measure frozen precipitation **[4]**.

3.2.3.2 Obstructions

Nearby obstructions can create adverse effects on precipitation measurements (e.g., funneling, reflection, and turbulence) which should be avoided. On the other hand, precipitation measurements may be highly sensitive to wind speed, especially where snowfall contributes a significant fraction of the total annual precipitation. Thus, some sheltering is desirable. The need to balance these two opposite effects requires some subjective judgment.

The best exposure may be found in orchards, openings in a grove of trees, bushes, or shrubbery, or where fences or other objects act together to serve as an effective wind-break. As a general rule, in sheltered areas where the height of the objects and their distance to the instrument is uniform, their height (above the instrument) should not exceed twice the distance (from the instrument) **[15]**. In open areas, the distance to obstructions should be at least two, and preferably four, times the height of the obstruction. It is also desirable in open areas which experience significant snowfall to use wind shields such as those used by the National Weather Service **[2, 9, 15]**.

3.2.3.3 Siting considerations

In view of the sensitivity to wind speed, every effort should be made to minimize the wind speed at the mouth opening of a precipitation gauge. This can be done by using wind shields. Where snow is not expected to occur in significant amounts or with significant frequency, use of wind shields is less important. However, the catch of either frozen or liquid precipitation is influenced by turbulent flow at the collector, and this can be minimized by the use of a wind shield.

3.2.4 Pressure

Although atmospheric pressure may be used in some modeling applications, it is not a required input variable for steady-state modeling applications. Moreover, the standard atmospheric pressure for the station elevation may often be sufficient for those applications which require station pressure; the model user's guide should be checked for specific model requirements.

3.2.5 Radiation

3.2.5.1 Probe placement

Pyranometers used for measuring incoming (solar) radiation should be located with an unrestricted view of the sky in all directions during all seasons, with the lowest solar elevation angle possible. Sensor height is not critical for pyranometers. A tall platform or rooftop is a desirable location **[2]**. Net radiometers should be mounted about 1 m above the ground **[2]**.

3.2.5.2 Obstructions

Pyranometers should be located to avoid obstructions casting a shadow on the sensor at any time. Also, light colored walls and artificial sources of radiation should be avoided **[2]**. Net radiometers should also be located to avoid obstructions to the field of view both upward and downward **[2]**.

3.2.5.3 Siting considerations

Solar radiation measurements should be taken in open areas free of obstructions. The ground cover under a net radiometer should be representative of the general site area. The given application will govern the collection of solar or net radiation data.

3.3 Complex Terrain Locations

For the purposes of this guidance, the term "complex terrain" is intended to mean any site where terrain effects on meteorological measurements may be significant. Terrain effects include aerodynamic wakes, density-driven slope flows, channeling, flow accelerations over the crest of terrain features, etc.; these flows primarily affect wind speed and wind direction measurements, however, temperature and humidity measurements may also be affected. The definition of significance depends on the application; for regulatory dispersion modeling applications, significance is determined by comparing stack-top height and/or an estimated plume height to terrain height - terrain which is below stack-top is classified as simple terrain (see Section 3.2), terrain between stack-top height and plume height is classified as intermediate terrain, and terrain which is above plume height is classified as complex terrain **[1]**.

Vertical gradients and/or discontinuities in the vertical profiles of meteorological variables are often significant in complex terrain. Consequently, measurements of the meteorological variables affecting transport and dispersion of a plume (wind direction, wind speed, and σ_θ) should be made at multiple levels in order to ensure that data used for modeling are representative of conditions at plume level. The ideal arrangement in complex terrain involves siting a tall tower between the source and the terrain feature of concern. The tower should be tall enough to provide measurements at plume level. Other terrain in the area should not significantly affect plume transport in a different manner than that measured by the tower. Since there are not many situations where this ideal can be achieved, a siting decision in complex terrain will almost always be a compromise. Monitoring options in complex terrain range from a single tall tower to multiple tall towers supplemented by data from one or more remote sensing platforms. Other components of the siting decision include determining tower locations, deciding whether or not a tower should be sited on a nearby terrain feature, and determining levels (heights) for monitoring. Careful planning is essential in any siting decision. Since each complex terrain situation has unique features to consider, no specific recommendations can be given to cover all cases. However, the siting process should be essentially the same in all complex terrain situations. Recommended steps in the siting process are as follows:

- Define the variables that are needed for a particular application.
- Develop as much information as possible to define what terrain influences are likely to be important. This should include examination of topographic maps of the area with terrain above physical stack height outlined. Preliminary estimates of plume rise should be made to determine a range of expected plume heights. If any site specific meteorological data are available, they should be analyzed to see what can be learned about the specific

terrain effects on air flow patterns. An evaluation by a meteorologist based on a site visit would also be desirable.

- Examine alternative measurement locations and techniques for required variables. Advantages and disadvantages of each technique/location should be considered, utilizing as a starting point the discussions presented above and elsewhere in this document.
- Optimize network design by balancing advantages and disadvantages.

It is particularly important in complex terrain to consider the end use of each variable separately. Guidance and concerns specific to the measurement of wind speed, wind direction, and temperature difference in complex terrain are discussed in the following sections.

3.3.1 Wind Speed

For use in plume rise calculations, wind speed should be measured at stack top or 100 m, whichever is lower. Ideally, the wind speed sensor should be mounted on a tower located near stack base elevation; however, a tower located on nearby elevated terrain may be used in some circumstances. In this latter case, the higher the tower above terrain the better (i.e. less compression effect); a 10-meter tower generally will not be sufficient. The measurement location should be evaluated for representativeness of both the dilution process and plume rise.

Great care should be taken to ensure that the tower is not sheltered in a closed valley (this would tend to over-estimate the occurrence of stable conditions) or placed in a location that is subject to streamline compression effects (this would tend to underestimate the occurrence of stable conditions). It is not possible to completely avoid both of these concerns. If a single suitable location cannot be found, then alternative approaches, such as multiple towers or a single tall tower supplemented by one or more remote sensing platforms should be considered in consultation with the Regional Office.

3.3.2 Wind Direction

The most important consideration in siting a wind direction sensor in complex terrain is that the measured direction should not be biased in a particular direction that is not experienced by the pollutant plume. For example, instruments on a meteorological tower located at the bottom of a well-defined valley may measure directions that are influenced by channeling or density-driven up-slope or down-slope flows. If the pollutant plume will be affected by the same flows, then the tower site is adequate. Even if the tower is as high as the source's stack, however, appreciable plume rise may take the plume out of the valley influence and the tower's measured wind direction may not be appropriate for the source (i.e., biased away from the source's area of critical impact).

The determination of potential bias in a proposed wind direction measurement is not an easy judgement to make. Quite often the situation is complicated by multiple flow regimes, and the existence of bias is not evident. This potential must be considered, however, and a rationale developed for the choice of measurement location. Research has indicated that a single wind measurement location/site may not be adequate to define plume transport direction in some situations. While the guidance in this document is concerned primarily with means to obtain a single hourly averaged value of each variable, it may be appropriate to utilize more than one measurement of wind direction to calculate an "effective" plume transport direction for each hour.

3.3.3 Temperature Difference

The requirements of a particular application should be used as a guide in determining how to make measurements of vertical temperature difference in complex terrain. Stable plume rise and the critical dividing streamline height (H_{crit}), which separates flow that tends to move around a hill (below H_{crit}) from flow that tends to pass over a hill (above H_{crit}), are both sensitive to the vertical temperature gradient. The height ranges of interest are from stack top to plume height for the former and from plume height to the top of the terrain feature for the latter. The direct measurement of the complete temperature profile is often desirable but not always practical. The following discussion presents several alternatives for measuring the vertical temperature gradient along with some pros and cons.

Tower measurement: A tower measurement of temperature difference can be used as a representation of the temperature profile. The measurement should be taken between two elevated levels on the tower (e.g. 50 and 100 meters) and should meet the specifications for temperature difference discussed in Section 5.0. A separation of 50 m between the two sensors is preferred. The tower itself could be located at stack base elevation or on elevated terrain: optimum location depends on the height of the plume. Both locations may be subject to radiation effects that may not be experienced by the plume if it is significantly higher than the tower.

The vertical extent of the temperature probe may be partially in and partially out of the surface boundary layer, or may in some situations be entirely contained in the surface boundary layer while the plume may be above the surface boundary layer.

Balloon-based temperature measurements: Temperature profiles taken by balloon-based systems can provide the necessary information but are often not practical for developing a long-term data base. One possible use of balloon-based temperature soundings is in developing better "default" values of the potential temperature gradient on a site-specific basis. A possible approach would be to schedule several periods of intensive soundings during the course of a year and then derive appropriate default values keyed to stability category and wind speed and/or other appropriate variables. The number and scheduling of these intensive periods should be established as part of a sampling protocol.

Deep-layer absolute temperature measurements: If the vertical scale of the situation being modeled is large enough (200 meters or more), it may be acceptable to take the difference between two independent measurements of absolute temperature (i.e., temperature measurements would be taken on two different towers, one at plant site and one on terrain) to serve as a surrogate measurement of the temperature profile. This approach must be justified on a case-by-case basis, and should be taken only with caution. Its application should be subject to the following limitations:

- Depth of the layer should be 200 meters at a minimum;
- The measurement height on each tower should be at least 60 meters;
- Horizontal separation of the towers should not exceed 2 kilometers;
- No internal boundary layers should be present, such as near shorelines; and
- Temperature profiles developed with the two-tower system should be verified with a program of balloon-based temperature profile measurements.

3.4 Coastal Locations

The unique meteorological conditions associated with local scale land-sea breeze circulations necessitate special considerations. For example, a stably stratified air mass over water can become unstable over land due to changes in roughness and heating encountered during daytime conditions and onshore flow. An unstable thermal internal boundary layer (TIBL) can develop, which can cause rapid downward fumigation of a plume initially released into the stable onshore flow. To provide representative measurements for the entire area of interest, multiple sites would be needed: one site at a shoreline location (to provide 10 m and stack height/plume height wind speed), and additional inland sites perpendicular to the orientation of the shoreline to provide wind speed within the TIBL, and estimates of the TIBL height. Where terrain in the vicinity of the shoreline is complex, measurements at additional locations, such as bluff tops, may also be necessary. Further specific measurement requirements will be dictated by the data input needs of a particular model. A report prepared for the Nuclear Regulatory Commission **[16]** provides a detailed discussion of considerations for conducting meteorological measurement programs at coastal sites.

3.5 Urban Locations

Urban areas are characterized by increased heat flux and surface roughness. These effects, which vary horizontally and vertically within the urban area, alter the wind pattern relative to the outlying rural areas (e.g., average wind speeds are decreased). The close proximity of buildings in downtown urban areas often precludes strict compliance with the previous sensor exposure guidance. For example, it may be necessary to locate instruments on the roof of the tallest available building. In such cases, the measurement height should take into account the proximity of nearby tall buildings and the difference in height between the building (on which the instruments are located) and the other nearby tall buildings.

In general, multiple sites are needed to provide representative measurements in a large urban area. This is especially true for ground-level sources, where low-level, local influences, such as street canyon effects, are important, and for multiple elevated sources scattered over an urban area. However, due to the limitations of the recommended steady-state guideline models (i.e. they recognize only a single value for each input variable on an hourly basis), and resource and practical constraints, the use of a single site is necessary. At the very least, the single site should be located as close as possible to the source in question.

3.6 Recommendations

Recommendations for siting and exposure of in situ meteorological sensors in simple terrain are as follows:

> *Sensors for wind speed and wind direction should be located over level, open terrain at a height of 10 m above ground level and at a distance at least ten times the height of nearby obstructions. For elevated releases, additional measurements should be made at stack top or 100 m, whichever is lower. Monitoring requirements for stacks 200 m and above should be determined in consultation with the appropriate EPA Regional Office.*
>
> *Temperature sensors should be located at 2 m. Probe placement for temperature difference measurements depend on the application. For use in estimating surface layer stability, the measurement should be made between $20z_0$ and $100z_0$; the same recommendation applies to temperature difference measurements for use in estimating the P-G stability category using the solar radiation delta-T method. For use in estimating stable plume rise, temperature difference measurements should be made across the plume rise layer, a minimum separation of 50 m is recommended for this application. Temperature sensors should be shielded to protect them from thermal radiation and any significant heat sources or sinks.*
>
> *Pyranometers used for measuring incoming (solar) radiation should be located with an unrestricted view of the sky in all directions during all seasons. Sensor height is not critical for pyranometers; a tall platform or rooftop is an acceptable location. Net radiometers should be mounted about 1 m above ground level.*

Specific recommendations applicable to siting and exposure of meteorological instruments in complex terrain are not possible. Generally, one should begin the process by conducting a screening analysis to determine, among other things, what terrain features are likely to be important; the screening analysis should also identify potential worse case meteorological conditions. This information should then be used to design a monitoring plan for the specific application.

Special siting considerations also apply to coastal and urban sites. Multiple sites, though often desirable, may not always be possible in these situations. In general, site selection for meteorological monitoring in support of regulatory modeling applications in coastal and urban locations should be conducted in consultation with the appropriate EPA Regional Office.

If the recommendations in this section cannot be achieved, then alternate approaches should be developed in consultation with the appropriate EPA Regional Office. Approval of site *selection for meteorological monitoring should be obtained from the permit granting authority prior to installation of any equipment.*

4. METEOROLOGICAL DATA RECORDING

The various meteorological data recording systems available range in complexity from very simple analog or mechanical pulse counter systems to very complex multichannel, automated, microprocessor-based digital data acquisition systems. The function of these systems is to process the electrical output signals from various sensors/transducers and convert them into a form that is usable for display and subsequent analysis. The sensor outputs may come in the form of electrical DC voltages, currents of varying amperage, and/or frequency-varying AC voltages.

4.1 Signal Conditioning

The simpler analog systems utilize the electrical output from a transducer to directly drive the varying pen position on a strip chart. For some variables, such as wind run (total passage of wind) and precipitation, the transducer may produce a binary voltage (either "on" or "off") which is translated into an event mark on the strip chart. Many analog systems and virtually all digital systems require a signal conditioner to translate the transducer output into a form that is suitable for the remainder of the data acquisition system. This translation may include amplifying the signal, buffering the signal (which in effect isolates the transducer from the data acquisition system), or converting a current (amperage) signal into a voltage signal.

4.2 Recording Mechanisms

Both analog and digital systems have a variety of data recording mechanisms or devices available. Analog data may be recorded as continuous traces on a strip chart or as event marks on a chart, as previously described, or as discrete samples on a multi point recorder. The multi point recorder will generally sample each of several variables once every several seconds. The traces for the different variables are differentiated by different colors of ink or by channel numbers printed on the chart next to the trace, or by both. The data collected by digital data acquisition systems may be recorded in hard copy form by a printer or terminal either automatically or upon request, and are generally also recorded on some machine-readable medium such as a magnetic disk storage or tape storage device or a solid-state (nonmagnetic) memory cartridge. Digital systems have several advantages over analog systems in terms of the speed and accuracy of handling the data, and are therefore preferred as the primary recording system. Analog systems may still be useful as a backup to minimize the potential for data loss. For wind speed and wind direction, the analog strip chart records can also provide valuable information to the person responsible for evaluating the data..

4.3 Analog-to-Digital Conversion

A key component of any digital data acquisition system is the analog-to-digital (A/D) converter. The A/D converter translates the analog electrical signal into a binary form that is suitable for subsequent processing by digital equipment. In most digital data acquisition systems a single A/D converter is used for several data channels through the use of a multiplexer. The rate at which the multiplexer channel switches are opened and closed determines the sampling rates for the channels - all channels need not be sampled at the same the frequency.

4.4 Data Communication

Depending on the type of system, there may be several data communication links. Typically the output signals from the transducers are transmitted to the on-site recording devices directly via hardwire cables. For some applications involving remote locations the data transmission may be accomplished via a microwave telemetering system or perhaps via telephone lines with a dial-up or dedicated line modem system.

4.5 Sampling Rates

The recommended sampling rate for a digital data acquisition system depends on the end use of the data. Substantial evidence and experience suggest that 360 data values evenly spaced during the sampling interval will provide estimates of the standard deviation to within 5 or 10% **[3]**. Estimates of the mean should be based on at least 60 samples to obtain a similar level of accuracy. Sometimes fewer samples will perform as well, but no general guide can be given for identifying these cases before sampling; in some cases, more frequent sampling may be required. If single-pass processing (as described in Section 6.2.1) is used to compute the mean scalar wind direction, then the output from the wind direction sensor (wind vane) should be sampled at least once per second to insure that consecutive values do not differ by more than 180 degrees.

The sampling rate for multi point analog recorders should be at least once per minute. Chart speeds should be selected to permit adequate resolution of the data to achieve the system accuracies recommended in Section 5.1. The recommended sampling rates are minimum values; the accuracy of the data will generally be improved by increasing the sampling rate.

4.6 Recommendations

A microprocessor-based digital data acquisition system should be used as the primary data recording system; analog data recording systems may be used as a backup. Wind speed and wind direction analog recording systems should employ continuous-trace strip-charts; other variables may be recorded on multi point charts. The analog charts used for backup should provide adequate resolution to achieve the system accuracies recommended in Section 5.1.

Estimates of means should be based on at least 60 samples (one sample per minute for an hourly mean). Estimates of the variance should be based on at least 360 samples (six samples per minute for an hourly variance). If single-pass processing is used to calculate the mean scalar wind direction then the output from the wind vane should be sampled at least once per second.

5. SYSTEM PERFORMANCE

5.1 System Accuracies

Accuracy is the amount by which a measured variable deviates from a value accepted as true or standard. Accuracy can be thought of in terms of individual component accuracy or overall system accuracy. For example, the overall accuracy of a wind speed measurement system includes the individual component accuracies of the cup or propeller anemometer, signal conditioner, analog-to-digital converter, and data recorder.

The accuracy of a measurement system can be estimated if the accuracies of the individual components are known. The system accuracy would be the square root of the sum of the squares of the random component accuracies **[17]**. The accuracies recommended for meteorological monitoring systems are listed in Table 5-1. These are stated in terms of overall system accuracies, since it is the data from the measurement system which are used in air quality modeling analyses. Recommended measurement resolutions, i.e., the smallest increments that can be distinguished, are also provided in Table 5-1. These resolutions are considered necessary to maintain the recommended accuracies, and are also required in the case of wind speed and wind direction for computations of standard deviations.

Table 5-1

Recommended System Accuracies and Resolutions

Meteorological Variable	System Accuracy	Measurement Resolution
Wind Speed (horizontal and vertical)	± (0.2 m/s + 5% of observed)	0.1 m/s
Wind Direction (azimuth and elevation)	± 5 degrees	1.0 degree
Ambient Temperature	± 0.5 °C	0.1 °C
Vertical Temperature Difference	± 0.1 °C	0.02 °C
Dew Point Temperature	± 1.5 °C	0.1 °C
Precipitation	± 10% of observed or ± 0.5 mm	0.3 mm
Pressure	± 3 mb (0.3 kPa)	0.5 mb
Solar Radiation	± 5% of observed	10 W/m^2

The recommendations provided in Table 5-1 are applicable to microprocessor-based digital systems (the primary measurement system). For analog systems, used as backup, these recommendations may be relaxed by 50 percent. The averaging times associated with the recommended accuracies correspond to the averaging times associated with the end use of the data (nominally, 1-hour averaging for regulatory modeling applications) and with the audit methods recommended to evaluate system accuracies.

5.2 Response Characteristics of Meteorological Sensors

The response characteristics of the sensors used in meteorological monitoring must be known to ensure that data are appropriate for the intended application. For example, an anemometer designed to endure the rigors experienced on an ocean buoy would not be suitable for monitoring fine scale turbulence in a wind tunnel; the latter application requires a more sensitive instrument with a faster response time (e.g., a sonic anemometer). On the other hand, a sonic anemometer is probably unnecessary if the data are to be used only to calculate hourly averages for use in a dispersion model. Recommended response characteristics for meteorological sensors used in support of air quality dispersion modeling are given in Table 5-2. Definitions of terms commonly associated with instrument response characteristics (including the terms used in Table 5-2) are provided in the following.

Calm. Any average wind speed below the starting threshold of the wind speed or direction sensor, whichever is greater **[4]**.

Damping ratio. The motion of a vane is a damped oscillation and the ratio in which the amplitude of successive swings decreases is independent of wind speed. The damping ratio, h, is the ratio of actual damping to critical damping. If a vane is critically damped, h=l and there is no overshoot in response to sudden changes in wind direction **[18] [19] [20]**.

Delay distance. The length of a column of air that passes a wind vane such that the vane will respond to 50% of a sudden angular change in wind direction **[19]** The delay distance is commonly specified as "50% recovery" using "10° displacement" **[2, 3]**.

Distance constant. The distance constant of a sensor is the length of fluid flow past the sensor required to cause it to respond to 63.2%, i.e., l - l/e, of the increasing step-function change in speed **[19,20]**. Distance constant is a characteristic of cup and propeller (rotational) anemometers.

Range. This is a general term which usually identifies the limits of operation of a sensor, most often within which the accuracy is specified.

Threshold (starting speed). The wind speed at which an anemometer or vane first starts to perform within its specifications20.

Time constant. The time constant is the period that is required for a (temperature) sensor to respond to 63.2%, i.e., l - l/e, of the step-wise change (in temperature). The term is applicable to any "first-order" sensors, those that respond asymptotically to a step change in the variable being measured, e.g., temperature, pressure, etc.

Table 5-2

Recommended Response Characteristics for Meteorological Sensors

Meteorological Variable	Sensor Specification(s)	
Wind Speed		
Horizontal	Starting Speed:	≤ 0.5 m/s
	Distance Constant:	≤ 5 m
Vertical	Starting Speed:	≤ 0.25 m/s
	Distance Constant:	≤ 5 m
Wind Direction	Starting Speed:	≤ 0.5 m/s @ 10 deg.
	Damping Ratio:	0.4 to 0.7
	Delay Distance:	≤ 5 m
Temperature	Time Constant:	≤ 1 minute
Temperature Difference	Time Constant:	≤ 1 minute
Dew Point Temperature	Time Constant:	≤ 30 minutes
	Range:	-30°C to +30°C
Solar Radiation	Time Constant:	5 sec.
	Operating Range:	-20°C to +40°C
	Spectral Response:	285 nm to 2800 nm

Several publications are available that either contain tabulations of reported sensor response characteristics **[18]**, **[21]** or specify, suggest or recommend values for certain applications **[2, 3, 9]**. Moreover, many manufacturers are now providing this information for the instruments they produce **[21]**. An EPA workshop report on meteorological instrumentation **[3]** expands on these recommendations for certain variables.

Manufacturers of meteorological instruments should provide evidence that the response characteristics of their sensors have been determined according to accepted scientific/technical methods, e.g., ASTM standards **[22]**. Verifying a manufacturer's claims that a meteorological sensor possesses the recommended response characteristics (Table 5-2) is another matter; such verification can accurately be accomplished only in a laboratory setting. In leu of a laboratory test, one must rely on quality assurance performance audit procedures (Section 8.4) - the latter will normally provide assurance of satisfactory performance.

5.3 Data Recovery

5.3.1 Length of Record

The duration of a meteorological monitoring program should be set to ensure that worst-case meteorological conditions are adequately represented in the data base; the minimum duration for most dispersion modeling applications is one year. Recommendations on the length of record for regulatory dispersion modeling as published in The Guideline on Air Quality Models **[1]** are: five years of National Weather Service (NWS) meteorological data or at least one year of site-specific data. Consecutive years from the most recent, readily available 5-year period are preferred.

5.3.2 Completeness Requirement

Regulatory analyses for the short-term ambient air quality standards (1 to 24-hour averaging) involve the sequential application of a dispersion model to every hour in the analysis period (one to five years); such analyses require a meteorological record for every hour in the analysis period. Substitution for missing or invalid data is used to meet this requirement. Applicants in regulatory modeling analyses are allowed to substitute for up to 10 percent of the data; conversely, the meteorological data base must be 90 percent complete (before substitution) in order to be acceptable for use in regulatory dispersion modeling. The following guidance should be followed for purposes of assessing compliance with the 90 percent completeness requirement:

- Lost data due to calibrations or other quality assurance procedures is considered missing data.
- A variable is not considered missing if data for a backup, collocated sensor is available.
- A variable is not considered missing if backup data from an analog system; which meets the applicable response, accuracy and resolution criteria; are available.

- Site specific measurements for use in stability classification are considered equivalent such that the 90 percent requirement applies to stability and not to the measurements (e.g., σ_E and σ_A) used for estimating stability.
- The 90 percent requirement applies on a quarterly basis such that 4 consecutive quarters with 90 percent recovery are required for an acceptable one-year data base.
- The 90 percent requirement applies to each of the variables wind direction, wind speed, stability, and temperature and to the joint recovery of wind direction, wind speed, and stability.

Obtaining the 90 percent goal will necessarily require a commitment to routine preventive maintenance and strict adherence to approved quality assurance procedures (Sections 8.5 and 8.6). Some redundancy in sensors, recorders and data logging systems may also be necessary. With these prerequisites, the 90 percent requirement should be obtainable with available high quality instrumentation. Applicants failing to achieve such are required to continue monitoring until 4 consecutive quarters of acceptable data with 90 percent recovery have been obtained. Substitutions for missing data are allowed, but may not exceed 10 percent of the hours (876 hours per year) in the data base. Substitution procedures are discussed in Section 6.8.

5.4 Recommendations

Recommended system accuracies and resolutions for meteorological data acquisition systems are given in Table 5-l. These requirements apply to the primary measurement system and assume use of a microprocessor digital recording system. If an analog system is used for backup, the values for system accuracy may be relaxed by 50 percent. Recommended response characteristics for meteorological sensors are given in Table 5-2. Manufacturer's documentation verifying an instrument's response characteristics should be reviewed to ensure that verification tests are conducted in a laboratory setting according to accepted scientific/technical methods. Data bases for use in regulatory dispersion modeling applications should be 90 percent complete (before substitution). The 90 percent requirement applies to each meteorological variable separately and to the joint recovery of wind direction, wind speed, and stability. Compliance with the 90 percent requirement should be assessed on a quarterly basis.

6. METEOROLOGICAL DATA PROCESSING

This section provides guidance for processing of meteorological data for use in air quality modeling as follows: Section 6.1 (Averaging and Sampling Strategies), Section 6.2 (Wind Direction, and Wind Speed), Section 6.3 (Temperature), Section 6.4 (Stability), Section 6.5 (Mixing Height), Section 6.6 (Boundary Layer Parameters), Section 6.7 (Use of Airport Data), and Section 6.8 (Treatment of Missing Data). Recommendations are summarized in Section 6.9.

6.1 Averaging and Sampling Strategies

Hourly averaging may be assumed unless stated otherwise; this is in keeping with the averaging time used in most regulatory air quality models. The hourly averaging is associated with the end product of data processing (i.e., the values that are passed on for use in modeling). These hourly averages may be obtained by averaging samples over an entire hour or by averaging a group of shorter period averages. If the hourly average is to be based on shorter period averages, then it is recommended that 15-minute intervals be used. At least two valid 15-minute periods are required to represent the hourly period. The use of shorter period averages in calculating an hourly value has advantages in that it minimizes the effects of meander under light wind conditions in the calculation of the standaard deviation of the wind direction, and it provides more complete information to the meteorologist reviewing the data for periods of transition. It also may allow the recovery of data that might otherwise be lost if only part of the hour is missing.

Sampling strategies vary depending on the variable being measured, the sensor employed, and the accuracy required in the end use of the data. The recommended sampling averaging times for wind speed and wind direction measurements is 1-5 seconds; for temperature and temperature difference measurements, the recommended sample averaging time is 30 seconds **[3]**.

6.2 Wind Direction and Wind Speed

This section provides guidance for processing of in situ measurements of wind direction and wind speed using conventional in situ sensors; i.e., cup and propeller anemometers and wind vanes. Guidance for processing of upper-air wind measurements obtained with remote sensing platforms is provided in Section 9. Recommendations are provided in the following for processing of winds using both scalar computations (Section 6.2.1) and vector computations (Section 6.2.2). Unless indicated otherwise, the methods recommended in Sections 6.2.1 and 6.2.2 employ single-pass processing; these methods facilitate real-time processing of the data as it is collected. Guidance on the treatment of calms is provided in Section 6.2.3. Processing of data to obtain estimates of turbulence parameters is addressed in Section 6.2.4. Guidance on the use of a power-law for extrapolating wind speed with height is provided in Section 6.2.5. The notation for this section is defined in Table 6-2.

Table 6-1

Notation Used in Section 6.2

Observed raw data

u_i	signed magnitude of the horizontal component of the wind vector (i.e., the wind speed)
θ_i	azimuth angle of the wind vector, measured clockwise from north (i.e., the wind direction)
w_i	signed magnitude of the vertical component of the wind vector
ϕ_i	elevation angle of the wind vector (bivane measurement)
N	the number of valid observations

Scalar wind computations

$\overline{u}$, $\overline{U}$	scalar mean wind speed
$\overline{u_h}$	harmonic mean wind speed
$\overline{\theta}$	mean azimuth angle of the wind vector (i.e. the mean wind direction)
$\overline{w}$	mean value of the vertical component of the wind speed
$\overline{\phi}$	mean elevation angle of the wind vector
σ_u	standard deviation of the horizontal component of the wind speed
σ_A, σ_θ	standard deviation of the azimuth angle of the wind
σ_w	standard deviation of the vertical component of the wind speed
σ_E, σ_ϕ	standard deviation of the elevation angle of the wind

Vector wind computations

$\overline{U}_{RV}$	resultant mean wind speed
$\overline{\theta}_{RV}$	resultant mean wind direction
$\overline{\theta}_{UV}$	unit vector mean wind direction
V_e	magnitude of the east-west component of the resultant vector mean wind (positive towards east)
V_n	magnitude of the north-south component of the resultant vector mean wind (positive towards the north)
V_x	magnitude of the east-west component of the unit vector mean wind
V_y	magnitude of the north-south component of the unit vector mean wind
x,y,z	standard right-hand-rule coordinate system with x-axis aligned towards the east.

6.2.1 Scalar Computations

The scalar mean wind speed is:

$$\overline{u} = \frac{1}{N} \sum_{1}^{N} u_i \qquad (6.2.1)$$

The harmonic mean wind speed is:

$$\overline{u_h} = \left(\frac{1}{N} \sum_{1}^{N} \frac{1}{u_i} \right)^{-1} \qquad (6.2.2)$$

The standard deviation of the horizontal component of the wind speed is:

$$\sigma_u = \left[\frac{1}{N} \left\{ \sum_{1}^{N} u_i^2 - \frac{1}{N} \left(\sum_{1}^{N} u_i \right)^2 \right\} \right]^{½} \qquad (6.2.3)$$

The wind direction is a circular function with values between l and 360 degrees. The wind direction discontinuity at the beginning/end of the scale requires special processing to compute a valid mean value. A single-pass procedure developed by Mitsuta and documented in reference **[23]** is recommended. The method assumes that the difference between successive wind direction samples is less than 180 degrees; to ensure such, a sampling rate of once per second or greater should be used (see Section 6.2.4). Using the Mitsuta method, the scalar mean wind direction is computed as:

$$\overline{\theta} = \frac{1}{N} \sum_{1}^{N} D_i \qquad (6.2.4)$$

where $D_i = \theta_i$; for I = 1

$D_i = D_{i-1} + \delta_i + 360$; for $\delta_i < -180$ and I > 1

$D_i = D_{i-1} + \delta_i$; for $|\delta_i| < 180$ and I > 1

$D_i = D_{i-1} + \delta_i - 360$; for $\delta_i > 180$ and I > 1

D_i is undefined for $\delta_i = 180$ and I > 1

$\delta_i = \theta_i - D_{i-1}$; for I > 1

θ_i is the azimuth angle of the wind vane for the i^{th} sample.

The following notes/cautions apply to the determination of the scalar mean wind direction using Equation. 6.2.4:

- If the result is less than zero or greater than 360, increments of 360 degrees should be added or subtracted, as appropriate, until the result is between zero and 360 degrees.
- Erroneous results may be obtained if this procedure is used to post-process sub-hourly averages to obtain an hourly average. This is because there can be no guarantee that the difference between successive sub-hourly averages will be less than 180 degrees.

The scalar mean wind direction, as defined in Equation. 6.2.4, retains the essential statistical property of a mean value, namely that the deviations from the mean must sum to zero:

$$\sum (\theta_i - \bar{\theta}) = 0 \tag{6.2.5}$$

By definition, the same mean value must be used in the calculation of the variance of the wind direction and, likewise, the standard deviation (the square root of the variance). The variance of the wind direction is given by:

$$\sigma_\theta^2 = \frac{1}{N} \sum (\theta_i - \bar{\theta})^2 \tag{6.2.6}$$

The standard deviation of the wind direction using the Mitsuta method is given by:

$$\sigma_A = \sigma_\theta = \left[\frac{1}{N} \left\{ \sum_1^N D_i^2 - \frac{1}{N} \left(\sum_1^N D_i \right)^2 \right\} \right]^{½} \tag{6.2.7}$$

Cases may arise in which the sampling rate is insufficient to assure that differences between successive wind direction samples are less than 180 degrees. In such cases, approximation formulas may be used for computing the standard deviation of the wind direction. Mardia **[24]** shows that a suitable estimate of the standard deviation (in radian measure) is:

$$\sigma_A = \sigma_\theta = \left[-2 \ln(R) \right]^{½} \tag{6.2.8}$$

where

$$R = (Sa^2 + Ca^2)^{½}$$

$$Sa = \frac{1}{N} \sum_1^N \sin(\theta_i)$$

$$Ca = \frac{1}{N} \sum_1^N \cos(\theta_i)$$

Several methods for calculating the standard deviation of the wind direction were evaluated by Turner **[25]**; a method developed by Yamartino **[26]** was found to provide excellent results for most cases. The Yamartino method is given in the following:

$$\sigma_A = \sigma_\theta = \arcsin(\epsilon)\ [1. + 0.1547\ \epsilon^3] \qquad (6.2.9)$$

where

$$\epsilon = \left[1. - \left(\overline{\sin(\theta_i)}^{\,2} + \overline{\cos(\theta_i)}^{\,2} \right)\right]^{1/2}$$

Note that hourly σ_θ values computed using 6.2.7, 6.2.8, or 6.2.9 may be inflated by contributions from long period oscillations associated with light wind speed conditions (e.g., wind meander). To minimize the effects of wind meander, the hourly σ_θ (for use e.g., in stability determinations - see Section 6.4.4.4) should be calculated based on four 15-minute values averaged as follows:

$$\sigma_\theta(1\text{-}hr) = \left[\left\{ (\sigma_{\theta_1})^2 + (\sigma_{\theta_2})^2 + (\sigma_{\theta_3})^2 + (\sigma_{\theta_4})^2 \right\} /4 \right]^{1/2} \qquad (6.2.10)$$

The standard deviation of the vertical component of the wind speed is:

$$\sigma_w = \left[\frac{1}{N} \left\{ \sum_1^N w_i^2 - \frac{1}{N} \left(\sum_1^N w_i \right)^2 \right\} \right]^{1/2} \qquad (6.2.11)$$

Similarly, the standard deviation of the elevation angle of the wind vector is:

$$\sigma_E = \sigma_\phi = \left[\frac{1}{N} \left\{ \sum_1^N \phi_i^2 - \frac{1}{N} \left(\sum_1^N \phi_i \right)^2 \right\} \right]^{1/2} \qquad (6.2.12)$$

Equation 6.2.12 is provided for completeness only. The bivane, which is used to measure the elevation angle of the wind, is regarded as a research grade instrument and is not recommended for routine monitoring applications. See Section 6.2.3 for recommendations on estimating σ_ϕ.

6.2.2 Vector Computations

From the sequence of N observations of θ_i and u_i, the mean east-west, V_e, and north-south, V_n, components of the wind are:

$$V_e = -\frac{1}{N} \sum u_i \sin(\theta_i) \qquad (6.2.13)$$

$$V_n = -\frac{1}{N} \sum u_i \cos(\theta_i) \qquad \textbf{(6.2.14)}$$

The resultant mean wind speed and direction are:

$$\overline{U}_{RV} = (V_e^2 + V_n^2)^{1/2} \qquad \textbf{(6.2.15)}$$

$$\overline{\theta}_{RV} = ArcTan\ (V_e/V_n) + FLOW \qquad \textbf{(6.2.16)}$$

where
$$FLOW \begin{array}{l} = +180; \quad for\ ArcTan(V_e/V_n) < 180 \\ = -180; \quad for\ ArcTan(V_e/V_n) > 180 \end{array}$$

Equation 6.2.16 assumes the angle returned by the ArcTan function is in degrees. This is not always the case and depends on the computer processor. Also, the ArcTan function can be performed several ways. For instance, in FORTRAN either of the following forms could be used:

ATAN(V_e/V_n)

or *ATAN2*(V_e, V_n).

The ATAN2 form avoids the extra checks needed to insure that V_n is nonzero, and is defined over a full 360 degree range.

The unit vector approach to computing mean wind direction is similar to the vector mean described above except that the east-west and north-south components are not weighted by the wind speed. Using the unit vector approach, equations 6.2.13 and 6.2.14 become:

$$V_x = -\frac{1}{N} \sum Sin\ \theta_i \qquad \textbf{(6.2.17)}$$

$$V_y = -\frac{1}{N} \sum Cos\theta_i \qquad \textbf{(6.2.18)}$$

The unit vector mean wind direction is:

$$\bar{\theta}_{UV} = ArcTan\ (V_x/V_y) + FLOW \qquad (6.2.19)$$

where

$$FLOW \begin{array}{l} = +180; \quad for\ ArcTan(V_x/V_y) < 180 \\ = -180; \quad for\ ArcTan(V_x/V_y) > 180 \end{array}$$

In general, the unit vector result will be comparable to the scalar average wind direction, and may be used to model plume transport.

6.2.3 Treatment of Calms

Calms, periods with little or no air movement, require special consideration in air quality evaluations; one of the more important considerations involves model selection. If the limiting air quality conditions are associated with calms, then a non-steady-state model, such as CALPUFF **[27]**, should be used. The use of a time varying 3-dimensional flow field in this model enables one to simulate conditions which are not applicable to steady-state models; e.g., recirculations and variable trajectories. Guidance for preparing meteorological data for use in CALPUFF is provided in the user's guide to the meteorological processor for this model **[28]**.

Steady-state models may be used for regulatory modeling applications if calms are not expected to be limiting for air quality. Calms require special treatment in such applications to avoid division by zero in the steady-state dispersion algorithm. EPA recommended steady-state models such as ISCST accomplish this with routines that nullify concentrations estimates for calm conditions and adjust short-term and annual average concentrations as appropriate. The EPA CALMPRO **[29]** program post-processes model output to achieve the same effect for certain models lacking this built-in feature. For similar reasons, to avoid unrealistically high concentration estimates at low wind speeds (below the values used in validations of these models - about 1 m/s) EPA recommends that wind speeds less than 1 m/s be reset to 1 m/s for use in steady-state dispersion models; the unaltered data should be retained for use in non-steady-state modeling applications. Calms should be identified in processed data files by flagging the appropriate records; user's guides for the model being used should be consulted for model specific flagging conventions.

For the purposes of this guidance and for the objective determination of calm conditions applicable to in situ monitoring, a calm occurs when the wind speed is below the starting threshold of the anemometer or vane, whichever is greater. For site-specific monitoring (using the recommended thresholds for wind direction and wind speed given in Table 5-2) a calm occurs when the wind speed is below 0.5 m/s. One should be aware that the frequency of calms are typically higher for NWS data bases because the sensors used to measure wind speed and wind direction have a higher threshold - typically 2 kts (1 m/s) - see Section 6.7.

6.2.4 Turbulence

6.2.4.1 Estimating σ_E from σ_w

Applications requiring the standard deviation of the elevation angle of the wind (e.g., see Section 6.4.4) should use the following approximation:

$$\boldsymbol{\sigma_E = \sigma_w / \bar{u}} \qquad \textbf{(6.2.20)}$$

where σ_E is the standard deviation of the elevation angle of the wind (radians)

σ_w is the standard deviation of the vertical component of the wind speed (m/s)

$\bar{u}$ is the scalar mean wind speed (m/s).

Weber et. al. **[30]** reported good performance for an evaluation using data measured at the Savannah River Laboratory for wind speeds greater than 2 m/s. In a similar study, Deihl **[31]** reported satisfactory performance for wind speeds greater than 2 m/s. In the Deihl study, the performance varied depending on the overall turbulence intensity. It is concluded from these studies that σ_E is best approximated by $\sigma_w/\bar{u}$ when wind speeds are greater than 2 m/s, and σ_E is greater than 3 degrees.

6.2.5 Wind Speed Profiles

Dispersion models recommended for regulatory applications employ algorithms for extrapolating the input wind speed to the stack-top height of the source being modeled; the wind speed at stack-top is used for calculating transport and dilution. This section provides guidance for implementing these extrapolations using default parameters and recommends procedures for developing site specific parameters for use in place of the defaults.

For convenience, in non-complex terrain up to a height of about 200 m above ground level, it is assumed that the wind profile is reasonably well approximated as a power-law of the form:

$$\boldsymbol{U_z = U_r (Z/Z_r)^p} \qquad \textbf{(6.2.21)}$$

where U_z = the scalar mean wind speed at height z above ground level

U_r = the scalar mean wind speed at some reference height Z_r, typically 10 m

p = the power-law exponent.

The power-law exponent for wind speed typically varies from about 0.1 on a sunny afternoon to about 0.6 during a cloudless night. The larger the power-law exponent the larger the vertical gradient in the wind speed. Although the power-law is a useful engineering approximation of the average wind speed profile, actual profiles will deviate from this relationship.

Site-specific values of the power-law exponent may be determined for sites with two levels of wind data by solving Equation (6.2.20) for p:

$$p = \frac{\ln(U) - \ln(U_r)}{\ln(Z) - \ln(Z_r)} \qquad \textbf{(6.2.21)}$$

As discussed by Irwin **[32]**, wind profile power-law exponents are a function of stability, surface roughness and the height range over which they are determined. Hence, power-law exponents determined using two or more levels of wind measurements should be stratified by stability and surface roughness. Surface roughness may vary as a function of wind azimuth and season of the year (see Section 6.4.2). If such variations occur, this would require azimuth and season dependent determination of the wind profile power-law exponents. The power-law exponents are most applicable within the height range and season of the year used in their determination. Use of these wind profile power-law exponents for estimating the wind at levels above this height range or to other seasons should only be done with caution. The default values used in regulatory models are given in Table 6-2.

Table 6-2

Recommended Power-law Exponents for Urban and Rural Wind Profiles

Stability Class	Urban Exponent	Rural Exponent
A	0.15	0.07
B	0.15	0.07
C	0.20	0.10
D	0.25	0.15
E	0.30	0.35
F	0.30	0.55

The following discussion presents a method for determining at what levels to specify the wind speed on a multi-level tower to best represent the wind speed profile in the vertical. The problem can be stated as, what is the percentage error resulting from using a linear interpolation over a height interval (between measurement levels), given a specified value for the power-law exponent. Although the focus is on wind speed, the results are equally applicable to profiles of other meteorological variables that can be approximated by power laws.

Let U_l represent the wind speed found by linear interpolation and U the "correct" wind speed. Then the fractional error is:

$$FE = (U_l - U)/U \qquad \textbf{(6.2.22)}$$

The fractional error will vary from zero at both the upper, Z_u, and lower, Z_l, bounds of the height interval, to a maximum at some intervening height, Z_m. If the wind profile follows a power law, the maximum fractional error and the height at which it occurs are:

$$FE_{\max} = \frac{(Z_l/Z_r)^p - (Z_m/Z_r)^p + A(Z_m - Z_l)/(Z_u - Z_l)}{(Z_m/Z_r)^p} \qquad \textbf{(6.2.23)}$$

where

$$A = (Z_u/Z_r)^p - (Z_l/Z_r)^p$$

and

$$Z_m = [pZ_l/(p-1)] - [p/(p-1)]\ (Z_l/Z_r)^p\ (Z_u - Z_l)/A$$

As an example, assume p equals 0.34 and the reference height, Z_r, is 10 m. Then for the following height intervals, the maximum percentage error and the height at which it occurs are:

Interval (m)	Maximum Error (%)	Height of Max Error (m)
2 - 10	-6.83	4.6
10 - 25	-2.31	16.0
25 - 50	-1.33	35.6
50 - 100	-1.33	71.2

As expected, the larger errors occur for the lower heights where the wind speed changes most rapidly with height. Thus, sensors should be spaced more closely together in the lower heights to best approximate the actual profile. Since the power-law is only an approximation of the actual profile, errors can occur that are larger than those estimated using (6.2.22). Even with this limitation, the methodology is useful for determining the optimum heights to place a limited number of wind sensors. The height Z_m represents the optimum height to place a third sensor given the location of the two surrounding sensors.

6.3 Temperature

Temperature is used in calculations to determine plume rise (Section 6.3.1), mixing height (Section 6.5), and various surface-layer parameters (Section 6.6). Unless indicated otherwise, ambient temperature measurements should be used in these calculations. Although not essential, the ambient temperature may also be used for consistency checking in QA procedures. Applications of vertical temperature gradient measurements are discussed in Section 6.3.2.

6.3.1 Use in Plume-Rise Estimates

Temperature is used in calculating the initial buoyancy flux in plume rise calculations as follows:

$$F = g(T_p - T_e)V/T_p \tag{6.3.1}$$

where the subscripts p and e indicate the plume and environmental values, respectively, and V is the volume flux **[13]**.

6.3.2 Vertical Temperature Gradient

Vertical temperature gradient measurements are used for classifying stability in the surface layer, in various algorithms for calculating surface scaling parameters, and in plume rise equations for stable conditions. For all of these applications the relative accuracy and resolution of the thermometers are of critical importance. Recommended heights for temperature gradient measurements in the surface layer are 2 m and 10 m. For use in estimating plume rise in stable conditions, the vertical temperature gradient should be determined using measurements across the plume rise layer; a minimum height separation of 50 m is recommended for this application.

6.4 Stability

Stability typing is employed in air quality dispersion modeling to facilitate estimates of lateral and vertical dispersion parameters [e.g., the standard deviation of plume concentration in the lateral (σ_y) and vertical (σ_z)] used in Gaussian plume models. The preferred stability typing scheme, recommended for use in regulatory air quality modeling applications is the scheme proposed in an article by Pasquill in 1961 **[33]**; the dispersion parameters associated with this scheme [often referred to as the Pasquill-Gifford (P-G) sigma curves] are used by default in most of the EPA recommended Gaussian dispersion models.

Table 6-3 provides a key to the Pasquill stability categories as originally defined; though impractical for routine application, the original scheme provided a basis for much of the developmental work in dispersion modeling. For routine applications using the P-G sigmas, the Pasquill stability category (hereafter referred to as the P-G stability category) should be calculated using the method developed by Turner **[34]**; Turner's method is described in Section 6.4.1. Subsequent sections describe alternative methods for estimating the P-G stability category when representative cloud cover and ceiling data are not available. These include a radiation-based method which uses measurements of solar radiation during the day and delta-T at night (Section 6.4.2) and turbulence-based methods which use wind fluctuation statistics (Sections 6.4.3 and 6.4.4). Procedures for the latter are based on the technical note published by Irwin in 1980 **[35]**; user's are referred to the technical note for background on the estimation of P-G stability categories.

Table 6-3

Key to the Pasquill Stability Categories

	Daytime Insolation			Nighttime cloud cover	
Surface wind speed (m/s)	Strong	Moderate	Slight	Thinly overcast or ≥4/8 low cloud	≤ 3/8
< 2	A	A - B	B	-	-
2 - 3	A - B	B	C	E	F
3 - 5	B	B - C	C	D	E
5 - 6	C	C - D	D	D	D
> 6	C	D	D	D	D

Strong insolation corresponds to sunny, midday, midsummer conditions in England; slight insolation corresponds to similar conditions in midwinter. Night refers to the period from one hour before sunset to one hour after sunrise. The neutral category, D, should be used regardless of wind speed, for overcast conditions during day or night.

6.4.1 Turner's method

Turner **[34]** presented a method for determining P-G stability categories from data that are routinely collected at National Weather Service (NWS) stations. The method estimates the effects of net radiation on stability from solar altitude (a function of time of day and time of year), total cloud cover, and ceiling height. Table 6-4 gives the stability class (1=A, 2=B,...) as a function of wind speed and net radiation index. Since the method was developed for use with NWS data, the wind speed is given in knots. The net radiation index is related to the solar altitude (Table 6-5) and is determined from the procedure described in Table 6-6. Solar altitude can be determined from the Smithsonian Meteorological Tables **[36]**. For EPA regulatory modeling applications, stability categories 6 and 7 (F and G) are combined and considered category 6.

Table 6-4

Turner's Key to the P-G Stability Categories

Wind Speed		Net Radiation Index						
(knots)	(m/s)	4	3	2	1	0	-1	-2
0,1	0 - 0.7	1	1	2	3	4	6	7
2,3	0.8 - 1.8	1	2	2	3	4	6	7
4,5	1.9 - 2.8	1	2	3	4	4	5	6
6	2.9 - 3.3	2	2	3	4	4	5	6
7	3.4 - 3.8	2	2	3	4	4	4	5
8,9	3.9 - 4.8	2	3	3	4	4	4	5
10	4.9 - 5.4	3	3	4	4	4	4	5
11	5.5 - 5.9	3	3	4	4	4	4	4
$\geq$ 12	$\geq$ 6.0	3	4	4	4	4	4	4

Table 6-5

Insolation Class as a Function of Solar Altitude

Solar Altitude Φ (degrees)	Insolation	Insolation Class Number
$60 < \Phi$	strong	4
$35 < \Phi \leq 60$	moderate	3
$15 < \Phi \leq 35$	slight	2
$\Phi \leq 15$	weak	1

Table 6-6

Procedure for Determining the Net Radiation Index

1. If the total cloud[1] cover is 10/10 and the ceiling is less than 7000 feet, use net radiation index equal to 0 (whether day or night).

2. For nighttime: (from one hour before sunset to one hour after sunrise):

   (a) If total cloud cover ≤ 4/10, use net radiation index equal to -2.

   (b) If total cloud cover > 4/10, use net radiation index equal to -1.

3. For daytime:

   (a) Determine the insolation class number as a function of solar altitude from Table 6-5.

   (b) If total cloud cover ≤5/10, use the net radiation index in Table 6-4 corresponding to the isolation class number.

   © If cloud cover >5/10, modify the insolation class number using the following six steps.

      (l) Ceiling <7000 ft, subtract 2.

      (2) Ceiling ≥7000 ft but <16000 ft, subtract 1.

      (3) total cloud cover equal 10/10, subtract 1. (This will only apply to ceilings ≥7000 ft since cases with 10/10 coverage below 7000 ft are considered in item 1 above.)

      (4) If insolation class number has not been modified by steps (1), (2), or (3) above, assume modified class number equal to insolation class number.

      (5) If modified insolation class number is less than 1, let it equal 1.

      (6) Use the net radiation index in Table 6-4 corresponding to the modified insolation class number.

[1] *Although Turner indicates total cloud cover, opaque cloud cover is implied by Pasquill and is preferred; EPA recommended meteorological processors, MPRM and PCRAMMET, will accept either.*

6.4.2 Solar radiation/delta-T (SRDT) method

The solar radiation/delta-T (SRDT) method retains the basic structure and rationale of Turner's method while obviating the need for observations of cloud cover and ceiling. The method, outlined in Table 6-7, uses the surface layer wind speed (measured at or near 10 m) in combination with measurements of total solar radiation during the day and a low-level vertical temperature difference (ΔT) at night (see Section 3.1.2.1 for guidance on probe placement for measurement of the surface layer ΔT). The method is based on Bowen et al. **[37]** with modifications as necessary to retain as much as possible of the structure of Turner's method.

Table 6-7

Key to Solar Radiation Delta-T (SRDT) Method for Estimating

Pasquill-Gifford (P-G) Stability Categories

DAYTIME

	Solar Radiation (W/m^2)			
Wind Speed (m/s)	≥ 925	925 - 675	675 - 175	< 175
< 2	A	A	B	D
2 - 3	A	B	C	D
3 - 5	B	B	C	D
5 - 6	C	C	D	D
≥ 6	C	D	D	D

NIGHTTIME

	Vertical Temperature Gradient	
Wind Speed (m/s)	< 0	≥ 0
< 2.0	E	F
2.0 - 2.5	D	E
≥ 2.5	D	D

6.4.3 σ_E method

The σ_E method (Tables 6-8a and 6-8b) is a turbulence-based method which uses the standard deviation of the elevation angle of the wind in combination with the scalar mean wind speed.

The criteria in Table 6-8a and Table 6-8b are for data collected at 10m and a roughness length of 15 cm. Wind speed and direction data collected within the height range from $20z_0$ to $100z_0$ should be used. For sites with very low roughness, these criteria are slightly modified. The lower bound of measurement height should never be less than 1.0 m; the upper bound should never be less than 10 m. To obtain 1-hour averages, the recommended sampling duration is 15 minutes, but it should be at least 3 minutes and may be as long as 60 minutes. The relationships employed in the estimation methods assume conditions are steady state. This is more easily achieved if the sampling duration is less than 30 minutes.

Table 6-8a

Vertical Turbulence[a] Criteria for Initial Estimate of Pasquill-Gifford (P-G) Stability Category. For use with Table 6-7b.

Initial estimate of P-G stability category	Standard deviation of wind elevation angle σ_E (degrees)
A	$11.5 \le \sigma_E$
B	$10.0 \le \sigma_E < 11.5$
C	$7.8 \le \sigma_E < 10.0$
D	$5.0 \le \sigma_E < 7.8$
E	$2.4 \le \sigma_E < 5.0$
F	$\sigma_E < 2.4$

[a] As indicated by the standard deviation of the elevation angle of the wind vector, σ_ϕ. Sigma-E and σ_E are aliases for σ_ϕ.

Table 6-8b

Wind Speed Adjustments for Determining Final Estimate of P-G Stability Category from σ_E. For use with Table 6-8a.

	Initial estimate of P-G Category	10-meter wind speed (m/s)	Final estimate of P-G Category
Daytime	A	u < 3	A
	A	$3 \leq u < 4$	B
	A	$4 \leq u < 6$	C
	A	$6 \leq u$	D
	B	u < 4	B
	B	$4 \leq u < 6$	C
	B	$6 \leq u$	D
	C	u < 6	C
	C	$6 \leq u$	D
	D, E, or F	ANY	D
Nighttime	A	ANY	D
	B	ANY	D
	C	ANY	D
	D	ANY	D
	E	u < 5	E
	E	$5 \leq u$	D
	F	u < 3	F
	F	$3 \leq u < 5$	E
	F	$5 \leq u$	D

If the site roughness length is other than 15 cm, the category boundaries listed in Table 6-8a may need to be adjusted. As an initial adjustment, multiply the Table 6-8a values by:

$$(z_o/15)^{0.2}$$

where z_o is the site roughness in centimeters. This factor, while theoretically sound, has not had widespread testing. It is likely to be a useful adjustment for cases when z_o is greater than 15 cm. It is yet problematical whether the adjustment is as useful for cases when z_o is less than 15 cm.

If the measurement height is other than 10 m, the category boundaries listed in Table 6-8a will need to be adjusted. As an initial adjustment, multiply the lower bound values by:

$$\mathbf{(Z/10)}^{P_\phi}$$

where Z is the measurement height in meters. The exponent P_ϕ is a function of the P-G stability category with values as follows:

P-G Stability	P_ϕ
A	0.02
B	0.04
C	0.01
D	-0.14
E	-0.31

The above suggestions summarize the results of several studies conducted in fairly ideal circumstances. It is anticipated that readers of this document are often faced with conducting analyses in less than ideal circumstances. Therefore, before trusting the Pasquill category estimates, the results should be spot checked. This can easily be accomplished. Choose cloudless days. In mid-afternoon during a sunny day, categories A and B should occur. During the few hours just before sunrise, categories E and F should occur. The bias, if any, in the turbulence criteria will quickly be revealed through such comparisons. Minor adjustments to the category boundaries will likely be needed to tailor the turbulence criteria to the particular site characteristics, and should be made in consultation with the reviewing agency.

6.4.4 σ_A method

The σ_A method (Tables 6-9a and 6-9b) is a turbulence-based method which uses the standard deviation of the wind direction in combination with the scalar mean wind speed. The criteria in Table 6-9a and Table 6-9b are for data collected at 10 m and a roughness length of 15 cm. Wind speed and direction data collected within the height range from $20z_o$ to $100z_o$ should be used. For sites with very low roughness, these criteria are slightly modified. The lower bound measurement height should never be less than 1 m. The upper bound should never be less than 10 m. To obtain 1-hour averages, the recommended sampling duration is 15 minutes, but it should be at least 3 minutes and may be as long as 60 minutes. The relationships employed in the estimation methods assume conditions are steady state. This is more easily achieved if the sampling duration is less than 30 minutes. To minimize the effects of wind meander, the 1-hour σ_A is defined using 15-minute values (see Equation. 6.2.10).

Table 6-9a

Lateral Turbulence[a] Criteria for Initial Estimate of Pasquill-Gifford (P-G) Stability Category. For use with Table 6-8b.

Initial estimate of P-G stability category	Standard deviation of wind azimuth angle σ_A
A	$22.5 \leq \sigma_A$
B	$17.5 \leq \sigma_A < 22.5$
C	$12.5 \leq \sigma_A < 17.5$
D	$7.5 \leq \sigma_A < 12.5$
E	$3.8 \leq \sigma_A < 7.5$
F	$\sigma_A < 3.8$

[a] As indicated by the standard deviation of the azimuth angle of the wind vector, σ_θ. Sigma-A, Sigma-Theta, and σ_A are aliases for σ_θ.

Table 6-9b

Wind Speed Adjustments for Determining Final Estimate of P-G Stability Category from σ_A. For use with Table 6-9a.

	Initial estimate of P-G Category	10-meter wind speed (m/s)	Final estimate of P-G Category
Daytime	A	$u < 3$	A
	A	$3 \leq u < 4$	B
	A	$4 \leq u < 6$	C
	A	$6 \leq u$	D
	B	$u < 4$	B
	B	$4 \leq u < 6$	C
	B	$6 \leq u$	D
	C	$u < 6$	C
	C	$6 \leq u$	D
	D, E, or F	ANY	D
Nighttime	A	$u < 2.9$	F
	A	$2.9 \leq u < 3.6$	E
	A	$3.6 \leq u$	D
	B	$u < 2.4$	F
	B	$2.4 \leq u < 3.0$	E
	B	$3.0 \leq u$	D
	C	$u < 2.4$	E
	C	$2.4 \leq u$	D
	D	ANY	D
	E	$u < 5$	E
	E	$5 \leq u$	D
	E		
	F	$u < 3$	F
	F	$3 \leq u < 5$	E
	F	$5 \leq u$	D

.

If the site roughness length is other than 15 cm, the category boundaries listed in Table 6-9a may need adjustment. As an initial adjustment, multiply the values listed by:

$$(z_o/15)^{0.2}$$

where z_o is the site roughness in centimeters. This factor, while theoretically sound, has not had widespread testing. It is likely to be a useful adjustment for cases when z_o is greater than 15 cm. It is yet problematical whether the adjustment is as useful for cases when z_o is less than 15 cm.

If the measurement height is other than 10 m, the category boundaries listed in Table 6-9a will need adjustment. As an initial adjustment, multiply the lower bound values listed by:

$$\mathbf{(Z/10)^{P_\theta}}$$

where Z is the measurement height in meters.

The exponent P_θ is a function of the P-G stability category with values as follows:

P-G Stability	P_θ
A	-0.06
B	-0.15
C	-0.17
D	-0.23
E	-0.38

The above suggestions summarize the results of several studies conducted in fairly ideal circumstances. It is anticipated that readers of this document are often faced with conducting analyses in less than ideal circumstances. Therefore, before trusting the Pasquill category estimates, the results should be spot checked. This can easily be accomplished. Choose cloudless days. In mid-afternoon during a sunny day, categories A and B should occur. During the few hours just before sunrise, categories E and F should occur. The bias, if any, in the turbulence criteria will quickly be revealed through such comparisons. Minor adjustments to the category boundaries will likely be needed to tailor the turbulence criteria to the particular site characteristics, and should be made in consultation with the reviewing agency.

6.4.5 Accuracy of stability category estimates

By virtue of its historic precedence and widespread use, EPA considers Turner's method **[34]** to be the benchmark procedure for determining P-G stability. Evaluations performed in developing the SRDT method indicate that this method identifies the same P-G stability category as Turner's method (Section 6.4.1) about 60 percent of the time and is within one category about 90 percent of the time (EPA, 1994) **[38]**. Results are not available comparing the performance of the σ_A and σ_E methods outlined above in this section. However, there are comparison results for similar methods. From these studies, it is concluded that the methods will estimate the same stability category about 50 percent of the time and will be within one category about 90 percent of the time. Readers are cautioned that adjustment of the turbulence criteria resulting from spot checks is necessary to achieve this performance. For additional information on stability classification using wind fluctuation statistics, see references **[39]**, **[40]**, **[41]**, and **[42]**.

6.5 Mixing Height

For the purposes of this guidance, mixing height is defined as the height of the layer adjacent to the ground over which an emitted or entrained inert non-buoyant tracer will be mixed (by turbulence) within a time scale of about one hour or less **[43]**. Taken literally, the definition means that routine monitoring of the mixing height is generally impractical. For routine application, alternative methods are recommended for estimating mixing heights based on readily available data.

The Holzworth method **[44]** is recommended for use when representative NWS upper-air data are available. This procedure relies on the general theoretical principle that the lapse rate is roughly dry adiabatic (no change in potential temperature with height) in a well-mixed daytime convective boundary layer (CBL); the Holzworth method is described in Section 6.5.1. Other alternatives include using estimates of mixing heights provided in CBL model output (Weil and Brower **[45]**; Paine **[46]**) and mixing heights derived from remote sensing measurements of turbulence or turbulence related parameters; the latter are discussed in Section 9.1.1.

6.5.1 The Holzworth Method

The Holzworth method **[44]** provides twice-per-day (morning and afternoon) mixing heights based on calculations using routine NWS upper-air data. The morning mixing height is calculated as the height above ground at which the dry adiabatic extension of the morning minimum surface temperature plus 5°C intersects the vertical temperature profile observed at 1200 Greenwich Mean Time (GMT). The minimum temperature is determined from the regular hourly airways reports from 0200 through 0600 Local Standard Time (LST). The "plus 5°C " was intended to allow for the effects of the nocturnal and early morning urban heat island since NWS upper-air stations are generally located in rural or suburban surroundings. However, it can also be interpreted as a way to include the effects of some surface heating shortly after sunrise. Thus, the time of the urban morning mixing height coincides approximately with that of the typical diurnal maximum concentration of slow-reacting pollutants in many cities, occurring around the morning commuter rush hours.

The afternoon mixing height is calculated in the same way, except that the maximum surface temperature observed from 1200 through 1600 LST is used. Urban-rural differences of maximum surface temperature are assumed negligible. The typical time of the afternoon mixing height may be considered to coincide approximately with the usual mid-afternoon minimum concentration of slow-reacting urban pollutants.

Hourly mixing heights, for use in regulatory dispersion modeling, are interpolated from these twice per day estimates. The recommended interpolation procedure is provided in the user's guide for the Industrial Source Complex (ISC) dispersion model **[47]**.

6.6 Boundary Layer Parameters

This section provides recommendations for monitoring in support of air quality dispersion models which incorporate boundary layer scaling techniques. The applicability of these techniques is particularly sensitive to the measurement heights for temperature and wind speed; the recommendations for monitoring, given in Section 6.6.4, consequently, focus on the placement of the temperature and wind speed sensors. A brief outline of boundary layer theory, given in the following, provides necessary context for these recommendations. The references for this section **[48]**, **[49]**, **[50]**, **[51]**, **[52]**, **[53]**, **[54]**, **[55]**, **[56]**, **[57]**, **[58]**, **[59]** provide more detailed information on boundary layer theory.

The Atmospheric Boundary Layer (ABL) can be defined as the lower layer of the atmosphere, where processes which contribute to the production or destruction of turbulence are significant; it is comprised of two layers, a lower surface layer, and a so-called "mixed" upper layer. The height of the ABL during daytime roughly coincides with the height to which pollutants are mixed (the mixing height, Section 6.5). During night-time stable conditions, the mixing height (h) is an order of magnitude smaller than the maximum daytime value over land; at night, h is typically below the top of the surface-based radiation inversion **[57]**.

The turbulent structure of the ABL is determined by the amount of heat released to the atmosphere from the earth's surface (sensible heat flux) and by interaction of the wind with the surface (momentum flux). This structure can be described using three length scales: z (the height above the surface), h (the mixing height), and L (the Obukhov length). The Obukhov length is defined by the surface fluxes of heat $H = \rho C_p \; \overline{w'\theta'}$ and momentum $u_*^2 = -\overline{u'w'}$, and reflects the height at which contributions to the turbulent kinetic energy from buoyancy and shear stress are comparable; the Obukhov length is defined as:

$$L = \frac{-\,u_*^3}{k\;(g/\theta)\;\overline{w'\theta'}} \qquad \textbf{(6.6.1)}$$

where k is the von Karman constant, θ is the mean potential temperature within the surface layer, g/θ is a buoyancy parameter, and u_* is the friction velocity. The three length scales define two independent non-dimensional parameters: a relative height scale (z/h), and a stability index (h/L)**[56]**.

Alternatives to the measurement of the surface fluxes of heat and momentum for use in (6.6.1) involve relating turbulence to the mean profiles of temperature and wind speed. The Richardson number, the ratio of thermal to mechanical production (destruction) of turbulent kinetic energy, is directly related to another non-dimensional stability parameter (z/L) and, thus, is a good candidate for an alternative to 6.6.1. The gradient Richardson number (R_g) can be approximated by:

$$R_g = \frac{g}{\overline{T}}\;\frac{\Delta\theta}{(\Delta u)^2}\;(z_2 - z_1) \qquad \textbf{(6.6.2)}$$

Large negative Richardson numbers indicate unstable conditions while large positive values indicate stable conditions. Values close to zero are indicative of neutral conditions. Use of (6.6.2) requires estimates of Δu based on measurements of wind speed at two levels in the surface layer; however, the level of accuracy required for these measurements is problematic (Δu is typically the same order of magnitude as the uncertainty in the wind speed measurement). The bulk Richardson number (R_b) which can be computed with only one level of wind speed is a more practical alternative:

$$R_b = \frac{g}{\overline{T}} \frac{\Delta\theta}{u^2} z \tag{6.6.3}$$

6.6.1 The Profile Method

The bulk Richardson number given in (6.6.3) is perhaps the simplest and most direct approach for characterizing the surface layer. For example, given the necessary surface layer measurements, one can derive both H and u_* from the integrated flux-profile equations: **[51,52]**

$$\Delta u = \frac{u_*}{k}\left[\ln\left(\frac{z_{i+1}}{z_i}\right) - \psi_m\left(\frac{z_{i+1}}{L}\right) + \psi_m\left(\frac{z_i}{L}\right)\right] \tag{6.6.4}$$

$$\Delta\theta = R\,\frac{\theta_*}{k}\left[\ln\left(\frac{z_{j+1}}{z_j}\right) - \psi_h\left(\frac{z_{j+1}}{L}\right) + \psi_h\left(\frac{z_j}{L}\right)\right] \tag{6.6.5}$$

where $\Delta u = (u_{i+1} - u_i)$, $\Delta\theta = (\theta_{j+1} - \theta_j)$; R is a parameter associated with the emperically determined similarity functions, ψ_m and ψ_h . EPA recommends using the emperical functions given in reference **[59]**; in this case the von Karman constant, k = 0.4 and R = 1. The temperature scale θ_* is related to the heat flux by:

$$H = -\rho\, C_p\, u_*\, \theta_* \tag{6.6.6}$$

Methods for solving the flux profile equations vary depending on what measurements are available. In the general case with two arbitrary levels each of temperature and wind speed [i.e., as in (6.6.4) and (6.6.5)], one can solve for the unknowns (u_*, θ_*, and L) by iteration; when temperature and wind speed are measured at the same heights, approximate analytic solutions can be used. Other simplifications result by replacing the lower wind speed measurement height in (6.6.4), z_i, with the surface roughness length (z_0) **[51,52]** ; see Section 6.6.3 for guidance on estimating surface roughness. A least squares method **[49]** is recommended when wind speed and temperature data are available for three or more levels. To ensure the data are representative of the surface layer, the wind speed and tempreature sensors should be located between $20z_0$ and $100z_0$; for sites with very low roughness, the sensors should be located between 1 and 10 m. Sampling durations for use in computing 1-hour averages should be in the range of 3 to 60 minutes; a sampling duration of 15 minutes or less is recommended if the steady-state assumption is in doubt.

6.6.2 The Energy Budget Method

An equation expressing the partitioning of energy at the surface may be used in place of (6.6.5) when measurements of $\Delta\theta$ are not available**[53, 54, 58]**. The expression for the surface energy budget is:

$$H_0 + \lambda E = Q^* - G \qquad \textbf{(6.6.7)}$$

where λE is the latent heat flux (λ is the latent heat of water vaporization and E is the evaporation rate), Q* is the net radiation and G the soil heat flux. $H_0 + \lambda E$ is the energy flux that is supplied to or extracted from the air, while Q* - G is the source or sink for this energy. Using $H_0 = -\rho C_p u_* \theta_*$, (6.6.7) can be written as:

$$\theta_* = \frac{\lambda E - Q^* + G}{\rho C_p u_*} \qquad \textbf{(6.6.8)}$$

In this equation λE, Q* and G can be parameterized in terms of the total cloud cover N, the solar elevation ϕ, the air temperature T, the friction velocity u_* and θ_* itself. The idea is to use (6.6.8) to write θ_* as a function of the variables N, ϕ, T, and u_*:

$$\theta_* = f_2(N, \phi, T, u_*) \qquad \textbf{(6.6.9)}$$

This equation then replaces (6.6.5). The further procedure of finding θ_* and u_* from (6.6.4) and (6.6.9) by iteration is similar to that used in the profile method.

6.6.3 Surface Roughness Length

The roughness length (z_0) is related to the roughness characteristics of the terrain. Under near-neutral conditions and with a homogeneous distribution of obstacles, a local value of z_0 can be determined from the logarithmic wind profile.

$$\boldsymbol{U(z) = \frac{u_*}{k} \ln(z/z_0)} \tag{6.6.10}$$

For general application, since typical landscapes almost always contain occasional obstructions, one should attempt to estimate an effective roughness length. The recommended method for estimating the effective roughness length is based on single level gustiness measurements σ_u **[60]**:

$$\boldsymbol{\frac{\sigma_u}{\overline{u}} = \frac{1}{\ln(z/z_0)}} \tag{6.6.11}$$

Wind measurements for use in (6.6.11) should be made between 20 z_0 and 100 z_0; to select the appropriate measurement level, an initial estimate of the effective roughness length must first be made based on a visual inspection of the landscape (see roughness classifications provided in Table 6-10). The sampling duration for σ_u and $\overline{u}$ should be between 3 and 60 minutes. Data collected for use in estimating the effective surface roughness should be stratified by wind speed (only data for wind speeds greater than 5 m/s should be used) and wind direction sector (using a minimum sector arc width of 30 degrees). Median z_0 values should be computed for each sector; results should then be inspected to determine whether the variation between sectors is significant. An average of the median values should be computed for adjacent sectors if the variation is not significant. Estimates of the effective surface roughness using these procedures are accurate to one significant figure; i.e., a computed value of 0.34 m should be rounded to 0.3 m. Documentation of the successful application of these procedures is provided in reference **[61]**.

Table 6-10

Terrain Classification in Terms of Effective Surface Roughness Length, Z_0

Terrain Description	Z_0 (m)
Open sea, fetch at least 5 km	0.0002
Open flat terrain; grass, few isolated obstacles	0.03
Low crops, occasional large obstacles, $x'/h > 20$[*]	0.10
High crops, scattered obstacles, $15 < x'/h < 20$[*]	0.25
Parkland, bushes, numerous obstacles, x'/h 10[*]	0.50
Regular large obstacle coverage (suburb, forest)	0.50 - 1.0

[*] x' = typical distance to upwind obstacle; h = height of obstacle

6.6.4 Guidance for Measurements in the Surface Layer

Monin-Obukhov (M-O) similarity theory is strictly applicable to steady-state horizontally homogeneous conditions in the surface layer. The temperature and wind speed measurements for use with M-O theory should be representative of a layer that is both high enough to be above the influence of the individual surface roughness elements and yet low enough to be within the surface layer; as a rule of thumb, the measurements should be made within the layer from $20z_0$ to $100z_0$ above the surface (2 - 10 m for a surface roughness of 0.1 m) **[57]**.

Data quality objectives and, consequently, instrument specifications for monitoring of temperature and wind speed in the surface layer are determined by the limitations imposed during the extreme stability conditions; basically this requires a monitoring design with the capability to resolve the variable gradients in temperature and wind speed that can exist within the surface layer under various conditions.

The depth of the surface layer where M-O similarity theory applies ranges from about one tenth of the ABL depth (h) during neutral conditions (typically 500 - 600 m) to the lesser of $|L|$ or 0.1 h during non-neutral conditions (less than 10 m during extreme stability conditions). This variability in the depth of the surface layer imposes limitations on what can be accomplished with a single fixed set of sensors. To ensure the availability of measurements representative of the entire surface layer during all stability conditions, one should employ a tall-tower (60 m or taller) equipped with wind and temperature sensors at several levels including, as a minimum, 2, 10 and 60 m. In the absence of a tall-tower, a standard 10-meter meteorological tower equipped with a single fixed set of sensors should be employed. Wind speed should be measured at the standard height of 10 m; the temperature difference should be measured between 2 and 10 m (for $z_0 \sim 0.1$ m). The usefulness of such a relatively low-lying measurement configuration lies in its applicability to both stable and unstable atmospheric conditions.

Application of M-O similarity should generally be restricted to low roughness sites located in relatively homogeneous terrain. For such sites, the reliability of the profile method for estimating surface layer parameters is primarily dependent on accurate temperature difference measurements (see Section 3.2.2 for siting and exposure of temperature sensors and Section 5.1 for sensor specifications).

6.7 Use of Airport Data

Airport data refers to surface weather observations collected in support of various NWS and Federal Aviation Administration (FAA) programs; most, although not all, of the surface weather observation sites are located at airports. For practical purposes, because airport data are readily available, most regulatory modeling was initially performed using these data. However, airport data do not meet this guidance - significant deviations include:

- The instruments used at airports are generally more robust and less sensitive than the instruments recommended in this guidance. For example, the thresholds for measuring wind direction and wind speed are higher than is recommended in this guidance; this results in a greater incidence of calms in airport data.
- Wind direction in airport data bases is reported to the nearest ten degrees - one degree resolution of wind direction is recommended in this guidance.
- Airport data for wind direction and wind speed are 2-minute averages; data for other variables, e.g., temperature and pressure are instantaneous readings - hourly averaging is recommended for all variables in this guidance.

Although data meeting this guidance are preferred, airport data continue to be acceptable for use in modeling. In fact observations of cloud cover and ceiling, data which traditionally have been provided by manual observation, are only available routinely in airport data; both of these variables are needed to calculate stability class using Turner's method (Section 6.4.1). The Guideline on Air Quality Models **[1]** recommends that modeling applications employing airport data be based on consecutive years of data from the most recent, readily available 5-year period. Airport data are available on the National Climatic Data Center (NCDC) World Wide Web site at http://www.ncdc.noaa.gov/. Documentation and guidance on NWS surface weather observations is provided in the Federal Meteorological Handbook No. 1 "Surface Weather Observations and Reports" **[62]**.

6.8 Treatment of Missing Data

Missing or invalid data should be flagged or replaced as appropriate depending on the model to be used. Note that the ISCST3 model recognizes specific flags for missing data; however, many models do not recognize flags and will not accept missing or invalid data. For use in these models, data bases with isolated one-hour gaps should be filled with estimates based on persistence or linear interpolation. Application specific procedures should be used for filling longer gaps; guidance for developing such procedures is provided in Section 6.8.1. Substitutions for missing data should only be made to complete the data set for modeling applications; substitution should not be used to attain the 90% completeness requirement for regulatory modeling applications (Section 5.3.2).

6.8.1 Substitution Procedures

This section provides general guidance on substitution procedures for use in completing meteorological data bases prior to their use in modeling. It is intended for use by applicants and reviewing agencies in the development of substitution protocols for application to regulatory air quality dispersion modeling. Substitution protocols should be included in a modeling protocol and submitted for approval to the reviewing authority prior to the modeling analysis.

Substitution procedures will vary depending on the nature of the application, the availability of alternative sources of meteorological data, and the extent of the missing or invalid data. If the data base is such that there are relatively few isolated one-hour gaps, then an interpolation procedure, which is easily automated, may provide the most practical method of substitution. However, it there are lengthy periods with missing or invalid data, then application specific procedures will generally be necessary.

The goal of substitution should be to replace missing data with a “best estimate” so as to minimize the probable error of the estimate. The following suggestions have been prioritized in order of increasing probable error.

Substitution procedures which are considered to be “best estimators” include the following:

- Persistence - Persistence is the use of data from the previous time period (hour). This procedure is applicable for most meteorological variables for isolated one-hour gaps; caution should be used when the gaps occur during day/night transition periods.
- Interpolation - This procedure is applicable for most meteorological variables for isolated one-hour gaps and, depending on circumstances, may be used for more extended periods (several hours) for selected variables; e.g., temperature. As in the case of persistence, caution should be used when the gaps occur during day/night transition periods.
- Profiling - Profiling (profile extrapolation) refers to the procedure in which missing data for one level in a multi-level data base (e.g., data from a meteorological tower) is replaced by an estimate based on data from an alternative level or levels in the same data base. The probable error of the profiling estimate does not increase with the duration of the missing data, as is the case for persistence and interpolation. Consequently, profiling becomes a better estimator compared to persistence and interpolation as the length of the missing data period increases. Profiling based on a power-law should be used for extrapolating wind speed with height; the stability dependent procedure discussed in Section 6.2.5 is recommended. Profiling based on lapse rate should be used for extrapolating temperature with height. Alternatively, with the approval of the reviewing authority, applicants may use site-specific profiling procedures for wind speed and temperature.

Substitution procedures which provide estimators with moderate probable error include the following:

- Substitution from sensors located at comparable levels at nearby locations with similar site-specific (surface-specific) characteristics.
- Persistence when used for more than several hours.
- Interpolation when used for more than several hours.

Substitution procedures which provide estimators with high probable error include the following:

- Substitution from measurements at nearby locations with dissimilar site-specific (surface-specific) characteristics.
- Substitution of a climatological value for a particular time period; e.g., a seasonal or monthly average.
- Substitution of simulated meteorology based, for example, on a boundary layer model.
- Substitution of "dummy data" such as a constant value for a variable.

6.9 Recommendations

The hourly scalar mean wind speed and wind direction should be used in steady-state Gaussian dispersion models. These statistics should be processed using the methods provided in Section 6.2.1; unit vector processing (Section 6.2.2) may also be used to estimate the hourly scalar mean wind direction. The standard deviation of the wind direction should be calculated using the techniques described in Section 6.2.1. Hourly statistics may be obtained by processing samples over an entire hour or by averaging sub-hourly statistics. The recommended sub-hourly averaging interval for wind data processing is 15 minutes; two valid 15-minute averages are required for a valid hourly average.

For the purposes of this guidance, a calm occurs when the wind speed is below the starting threshold of the anemometer or vane, whichever is greater. Calms require special treatment in such applications to avoid division by zero in the steady-state dispersion algorithm. For similar reasons, to avoid unrealistically high concentration estimates at low wind speeds (below the values used in validations of these models - about 1 m/s) EPA recommends that wind speeds less than 1 m/s be reset to 1 m/s for use in steady-state dispersion models; the unaltered data should be retained for use in non-steady-state modeling applications. Calms should be identified in processed data files by flagging the appropriate records; user's guides for the model being used should be consulted for model specific flagging conventions.

Recommended sampling and processing strategies for the primary meteorological variables for various applications are given in Table 6-1.

The Pasquill-Gifford (P-G) stability category should be determined with Turner's method (Section 6.4.1) using site-specific wind speed measurements at or near 10 m and representative *cloud cover and ceiling height. Other approved methods for estimating the P-G stability category, for use when representative cloud cover and ceiling observations are not available, include the solar radiation delta-T (SRDT) method described in Section 6.4.2, and turbulence-based methods using site-specific wind fluctuation statistics:* σ_E *(Section 6.4.3) or* σ_A *(Section 6.4.4). Alternative methods for determining stability category should be evaluated in consultation with the Regional Office.*

*Emperical relationships for use in models employing boundary layer scaling techniques should be selected in accordance with a von Karmam constant of 0.4; recmmended emperical relationships are given in reference **[59]**.*

Missing data should be flagged or replaced as appropriate depending on the model to be used. Isolated one-hour gaps in meteorological data bases used in regulatory modeling should be filled with estimates bases on persistence or interpolation. Application specific procedures should be used to fill longer gaps

If the recommendations in this section cannot be achieved, then alternative approaches should be developed in consultation with the EPA Regional Office.

7. DATA REPORTING AND ARCHIVING

Meteorological data collected for use in regulatory modeling applications should be made available to the regulatory agency as necessary. In some cases, as part of an oversight function, agencies may require periodic or even real-time access to the data as it is being collected. The regulatory agency may, in addition, require long-term archival of meteorological data bases used in some applications [e.g., analyses supporting State Implementation Plan (SIP) actions and Prevention of Significant deterioration (PSD) permits]. Procedures for compliance with such requirements should be worked out with the agency and documented in the monitoring protocol prior to commencement of monitoring.

7.1 Data Reports

The following general recommendations apply to meteorological data bases being prepared for use in regulatory modeling applications. All meteorological data should be reduced to hourly averages using the procedures provided in Section 6. The data should be recorded in chronological order; records should be labeled according to the observation time (defined as the time at the end of the averaging period; i.e., the hour ending). If possible, each data record should contain the data for one hourly observation (one record per hour). The first four fields of each data record should identify the year, month, day and hour of the observation. The data records should be preceded by a header record providing the following information:

- Station name
- Station location (latitude, longitude, and time zone)
- Station elevation
- Period of record and number of records
- Validation level (see Section 8)

A summary report should accompany each meteorological data base prepared for use in regulatory modeling applications. The summary report should provide the following information:

- number and percent of hours with complete/valid data.
- number and percent of hours with valid stability data.
- number and percent of hours with valid wind speed and wind direction data including valid calms.
- list of hours requiring substitutions including identification of the missing variable and the substitution protocol employed.

7.2 Data Archives

Meteorological data used in support of some regulatory actions (e.g, SIP revisions and PSD permit applications) may be needed in support of continuing actions for these regulations and, consequently should be archived by the agency with permit granting authority; normally the State. Such an archive should be designed for the data actually used in the regulatory application - i.e., the processed data, but may also include some raw data. Archival of other raw data is at the discretion of the applicant. The processed meteorological data should be archived initially for one year with provisions for review and extension to five years, ten years, or indefinite. Where data were originally reduced from strip chart records, the charts should also be archived. Original strip chart records should be retained for a minimum of five years. If an archive is to be eliminated, an attempt should be made to contact potential user's who might be affected by such an action.

7.3 Recommendations

Procedures for compliance with reporting and archiving requirements should be worked out with the agency and documented in the monitoring protocol prior to commencement of monitoring.

Meteorological data provided to regulatory agencies for use in modeling should be reduced to hourly averages using the procedures provided in Section 6. The data should be recorded in chronological order; records should be labeled according to the observation time (defined as the time at the end of the averaging period; i.e., the hour ending).

Meteorological data used in support of SIP revisions or PSD permit applications should be archived initially for one year with provisions for review and extension to five years, ten years, or indefinite.

8. QUALITY ASSURANCE AND QUALITY CONTROL

Quality Assurance/Quality Control (QAQC) procedures are required to ensure that the data collected meet standards of reliability and accuracy (see Section 5.1). Quality Control (QC) is defined as those operational procedures that will be routinely followed during the normal operation of the monitoring system to ensure that a measurement process is working properly. These procedures include periodic calibration of the instruments, site inspections, data screening, data validation, and preventive maintenance. The QC procedures should produce quantitative documentation to support claims of accuracy. Quality Assurance (QA) is defined as those procedures that will be performed on a more occasional basis to provide assurance that the measurement process is producing data that meets the data quality objectives (DQO). These procedures include routine evaluation of how the QC procedures are implemented (system audits) and assessments of instrument performance (performance audits).

The QAQC procedures should be documented in a Quality Assurance Project Plan (QAPP) and should include a "sign-off" by the appropriate project or organizational authority. The QAPP should include the following **[63]**:

1. Project description - how meteorology is to be used
2. Project organization - how data validity is supported
3. QA objective - how QA will document validity claims
4. Calibration method and frequency - for meteorology
5. Data flow - from samples to archived valid values
6. Validation and reporting methods - for meteorology
7. Audits - performance and system
8. Preventive maintenance
9. Procedures to implement QA objectives - details
10. Management support - corrective action and reports

It is important that the person providing the QA be independent of the organization responsible for the collection of the data and the maintenance of the measurement systems. Ideally, this person should be employed by an independent company. There should not be any lines of intimidation available to the operators which might be used to influence the QA audit report and actions. With identical goals of valid data, the QA person should encourage the operator to use the same methods the QA person uses (presumably these are the most comprehensive methods) when challenging the measurement system during a performance audit. When this is done, the QA task reduces to spot checks of performance and examination of records thus providing the best data with the best documentation at the least cost.

8.1 Instrument Procurement

The specifications required for the applications for which the data will be used (see Sections 5.0 and 6.0) along with the test method to be used to determine conformance with the specification should be a part of the procurement document. A good QA Plan will require a QA sign-off of the procurement document for an instrument system containing critical requirements. An instrument should not be selected solely on the basis of price and a vague description, without detailed documentation of sensor performance.

8.1.1 Wind Speed

This section provides guidance for procurement of anemometers (i.e., mechanical wind speed sensors employing cups or vane-oriented propellers) which rely on the force of the wind to turn a shaft. Guidance for the procurement of remote sensors for the measurement of wind speed is provided in Section 9. Other types of wind speed sensors (e.g., hot wire anemometers and sonic anemometers) are not commonly used for routine monitoring and are beyond the scope of this guide. An example performance specification for an anemometer is shown in Table 8-1.

Table 8-1

Example Performance Specification for an Anemometer

Range	0.5 m/s to 50 m/s
Threshold[1]	≤ 0.5 m/s
Accuracy (error)[1,2]	≤ (0.2 m/s + 5% of observed)
Distance Constant[1]	≤ 5 m at 1.2 kg/m^3 (at std sea-level density)

[1] As determined by wind tunnel test conducted on production samples in accordance with ASTM D-22.11 test methods

[2] aerodynamic shape (cup or propeller) with permanent serial number to be accompanied by test report, traceable to NBS, showing rate of rotation vs. wind speed at 10 speeds.

The procurement document should ask for (1) the starting torque of the anemometer shaft (with cup or propeller removed) which represents a new bearing condition, and (2) the starting torque above which the anemometer will be out of specification.; when the latter value is exceeded, the bearings should be replaced.

The ASTM test cited above includes a measurement of off-axis response. Some anemometer designs exhibit errors greater than the accuracy specification with off-axis angles of as little as 10 degrees. However, there is no performance specification for this type of error at this time, due to a lack of sufficient data to define what the specification should be.

8.1.2 Wind Direction

This section provides guidance for procurement of wind vanes; i.e., mechanical wind direction sensors which rely on the force of the wind to turn a shaft. Guidance for the procurement of remote sensors for the measurement of wind direction is provided in Section 9.

The wind direction measurement with a wind vane is a relative measurement with respect to the orientation of the direction sensor. There are three parts to this measurement which must be considered in quality assurance. These are: (l) the relative accuracy of the vane performance in converting position to output, (2) the orientation of the vane both horizontal (with respect to "true north") and vertical (with respect to a level plane), and (3) the dynamic response of the vane and conditioning circuit to changes in wind direction.

The procurement document should ask for: (1) the starting torque of the vane shaft (with the vane removed) which represents a new bearing (and potentiometer) condition, and (2) the starting torque above which the vane will be out of specification.; when the latter value is exceeded, the bearings should be replaced. An example performance specification for a wind vane is shown in Table 8-2.

Table 8-2

Example Performance Specification for a Wind Vane

Range	1 to 360 or 540 degrees
Threshold[1]	$\leq$ 0.5 m/s
Accuracy (error)[1]	$\leq$ 3 degrees relative to sensor mount or index
	$\leq$ 5 degrees absolute error for installed system
Delay Distance[1]	$\leq$ 5 m at 1.2 kg/m^3 (at std sea-level density)
Damping Ratio[1]	$\geq$ 0.4 at 1.2 kg/m^3 or
Overshoot[1]	$\leq$ 25% at 1.2 kg/m^3

[1] As determined by wind tunnel test conducted on production samples in accordance with ASTM D-22.11 test methods

The range of 1 to 540 degrees was originally conceived to minimize strip chart "painting" when the direction varied around 360 degrees. It also minimizes errors (but does not eliminate them) when sigma meters are used. It may also provide a means of avoiding some of the "dead band" errors from a single potentiometer. In these days of "smart" data loggers, it is possible to use a single potentiometer (1 to 360 degree) system without excessive errors for either average direction or σ_A.

If the wind direction samples are to be used for the calculation of σ_A, the specification should also include a time constant requirement for the signal conditioner. Direction samples should be effectively instantaneous. At 5 m/s, a 1m delay distance represents 0.2 seconds. A signal conditioner specification of a time constant of <0.2 seconds would insure that the σ_A value was not attenuated by an averaging circuit provided for another purpose.

8.1.3 Temperature and Temperature Difference

When both temperature and differential temperature are required, it is important to specify both accuracy and relative accuracy (not to be confused with precision or resolution). Accuracy is performance compared to truth, usually provided by some standard instrument in a controlled environment. Relative accuracy is the performance of two or more sensors, with respect to one of the sensors or the average of all sensors, in various controlled environments. A temperature sensor specification might read:

Range	-40 to +60 °C.
Accuracy (error)	$\leq$ 0.5 °C.

A temperature difference specification might read:

Range	-5 to +15 °C.
Relative accuracy (error)	$\leq$ 0.1 °C.

While calibrations and audits of both accuracy and relative accuracy are usually conducted in controlled environments, the measurement is made in the atmosphere. The greatest source of error is usually solar radiation. Solar radiation shield specification is therefore an important part of the system specification. Motor aspirated radiation shields (and possibly high performance naturally ventilated shields) will satisfy the less critical temperature measurement. For temperature difference, it is critical that the same design motor aspirated shield be used for both sensors. The expectation is that the errors from radiation (likely to exceed 0.2 °C) will zero out in the differential measurement. A motor aspirated radiation shield specification might read:

Radiation range	-100 to 1300 W/m^2
Flow rate	3 m/s or greater
Radiation error	< 0.2 °C.

8.1.4 Dew Point Temperature

Sensors for measuring dew point temperature can be particularly susceptible to precipitation, wind, and radiation effects. Therefore, care should be taken in obtaining proper (manufacturer-recommended) shielding and aspiration equipment for the sensors. If both temperature and dew point are to be measured, aspirators can be purchased which will house both sensors. If measurements will be taken in polluted atmospheres, gold wire electrodes will minimize corrosion problems. For cooled mirror sensors consideration should be given to the susceptibility of the mirror surface to contamination.

8.1.5 Precipitation

For areas where precipitation falls in a frozen form, consideration should be given to ordering an electrically heated rain and snow gauge. AC power must be available to the precipitation measurement site. For remote sites where AC power is not available, propane-heated gauges can be ordered. However, if air quality measurements are being made at the same location, consideration should be given to the air pollutant emissions in the propane burner exhaust.

Air movement across the top of a gauge can affect the amount of catch. For example, Weiss **[64]** reports that at a wind speed of 5 mph, the collection efficiency of an unshielded gauge decreased by 25%, and at 10 mph, the efficiency of the gauge decreased by 40%. Therefore, it is recommended that all precipitation gauges be installed with an Alter-type wind screen, except in locations where frozen precipitation does not occur.

Exposure is very important for precipitation gauges; the distance to nearby structures should be at least two to four times the height of the structures (see Section 3.1.3). Adequate lengths of cabling must be ordered to span the separation distance of the gauge from the data acquisition system. If a weighing gauge will be employed, a set of calibration weights should be obtained.

8.1.6 Pressure

The barometric pressure sensor should normally have a proportional and linear electrical output signal for data recording. Alternately, a microbarograph can be used with a mechanical recording system. Some barometers operate only within certain pressure ranges; for these, care should be taken that the pressure range is appropriate for the elevation of the site where measurements will be taken.

8.1.7 Radiation

Radiation instruments should be selected from commercially available and field-proven systems. These sensors generally have a low output signal, so that they should be carefully matched with the signal conditioner and data acquisition system. Another consideration in the selection of data recording equipment is the fact that net radiometers have both positive and negative voltage output signals.

8.2 Installation and Acceptance Testing

The installation period is the optimal time to receive appropriate training in instrument principles, operations, maintenance, and troubleshooting, as well as data interpretation and validation. Meteorological consultants as well as some manufacturers and vendors of meteorological instruments provide these services.

An acceptance test is used to determine if an instrument performs according to the manufacturer's specifications **[2]**. Manufacturer's procedures for unpacking, inspection, installation, and system diagnostics should be followed to assure that all components are functioning appropriately. All acceptance-testing activities should be documented in the station log.

8.2.1 Wind Speed

This section provides guidance for the acceptance testing of anemometers (i.e., mechanical wind speed sensors employing cups or vane-oriented propellers) which rely on the force of the wind to turn a shaft. Guidance for the acceptance testing of remote sensors for the measurement of wind speed is provided in Section 9. Other types of wind speed sensors (e.g., hot wire anemometers and sonic anemometers) are not commonly used for routine monitoring and are beyond the scope of this guide.

A technical acceptance test may serve two purposes. First, it can verify that the instrument performs as the manufacturer claims, assuming the threshold, distance constant and transfer function (rate of rotation vs. wind speed) are correct. This test catches shipping damage, incorrect circuit adjustments, poor workmanship, or poor QA by the manufacturer. This level of testing should be equivalent to a field performance audit. The measurement system is challenged with various rates of rotation on the anemometer shaft to test the performance from the transducer in the sensor to the output. The starting torque of the bearing assembly is measured and compared to the range of values provided by the manufacturer (new and replacement).

The other purpose of a technical acceptance test is to determine if the manufacturer really has an instrument which will meet the specification. This action requires a wind tunnel test. The results would be used to reject the instrument if the tests showed failure to comply. An independent test laboratory is recommended for conducting the ASTM method test.

The specification most likely to fail for a low cost anemometer is threshold, if bushings are used rather than quality bearings. A bushing design may degrade in time faster than a well designed bearing assembly and the consequence of a failed bushing may be the replacement of the whole anemometer rather than replacement of a bearing for a higher quality sensor. A receiving inspection cannot protect against this problem. A mean-time-between-failure specification tied to a starting threshold torque test is the only reasonable way to assure quality instruments if quality brand names and model numbers cannot be required.

8.2.2 Wind Direction

This section provides guidance for the acceptance testing of wind vanes; i.e., mechanical wind direction sensors which rely on the force of the wind to turn a shaft. Guidance for the acceptance testing of remote sensors for the measurement of wind direction is provided in Section 9.

A technical acceptance test can verify the relative direction accuracy of the wind vane by employing either simple fixtures or targets within a room established by sighting along a 30-60-90 triangle. There is no acceptance test for sighting or orientation, unless the manufacturer supplies an orientation fixture and claims that the sensor is set at the factory to a particular angle (180 degrees for example) with respect to the fixture.

If σ_A is to be calculated from direction output samples, the time constant of the output to an instantaneous change should be estimated. If the direction output does not change as fast as a test meter on the output can react, the time constant is too long.

If σ_A is calculated by the system, a receiving test should be devised to check its performance. The manual for the system should describe tests suitable for this challenge.

8.2.3 Temperature and Temperature Difference

The simplest acceptance test for temperature and temperature difference would be a two point test, room temperature and a stirred ice slurry. A reasonably good mercury-in-glass thermometer with some calibration pedigree can be used to verify agreement to within l °C. It is important to stir the liquid to avoid local gradients. It should not be assumed that a temperature difference pair will read zero when being aspirated in a room. If care is taken that the air drawn into each of the shields comes from the same well mixed source, a zero reading might be expected.

A second benefit of removing the transducers from the shields for an acceptance test comes to the field calibrator and auditor. Some designs are hard to remove and have short leads. These conditions can be either corrected or noted when the attempt is first made in the less hostile environment of a receiving space.

8.2.4 Dew Point Temperature

A dew point temperature acceptance test at one point inside a building, where the rest of the system is being tested, will provide assurance that connections are correct and that the operating circuits are functioning. The dew point temperature for this test should be measured with a wet-dry psychrometer (Assman type if possible) or some other device in which some measure of accuracy is documented. If it is convenient to get a second point outside the building, assuming that the dew point temperature is different outside (usually true if the building is air conditioned with water removed or added), further confidence in the performance is possible. Of course, the manufacturer's methods for checking parts of the system (see the manual) should also be exercised.

8.2.5 Precipitation

The receiving inspection for a precipitation gauge is straightforward. With the sensor connected to the system, check its response to water (or equivalent weight for weighing gauges) being introduced into the collector. For tipping bucket types, be sure that the rate is less than the equivalent of one inch (25mm) per hour if the accuracy check is being recorded. See the section on calibration (8.3) for further guidance.

8.2.6 Pressure

A check inside the building is adequate for an acceptance test of atmospheric pressure. An aneroid barometer which has been set to agree with the National Weather Service (NWS) equivalent sea-level pressure can be used for comparison. If station pressure is to be recorded by the pressure sensor, be sure that the aneroid is set to agree with the NWS station pressure and not the pressure broadcast on radio or television. A trip to the NWS office may be necessary to set the aneroid for this agreement since the station pressure is sensitive to elevation and the NWS office may be at a different elevation than the receiving location.

8.2.7 Radiation

A simple functional test of a pyranometer or solarimeter can be conducted with an electrical light bulb. With the sensor connected to the system as it will be in the field, cover it completely with a box with all cracks taped with an opaque tape. Any light can bias a "zero" check. The output should be zero. Do not make any adjustments without being absolutely sure the box shields the sensor from any direct, reflected, or diffuse light. Once the zero is recorded, remove the box and bring a bulb (100 watt or similar) near the sensor. Note the output change. This only proves that the wires are connected properly and the sensor is sensitive to light.

If a net radiometer is being checked, the bulb on the bottom should induce a negative output and on the top a positive output. A "zero" for a net radiometer is much harder to simulate. The sensor will (or may) detect correctly a colder temperature on the bottom of the shielding box than the top, which may be heated by the light fixtures in the room. Check the manufacturer's manual for guidance.

8.3 Routine Calibrations

A calibration involves measuring the conformance to or discrepancy from a specification for an instrument and an adjustment of the instrument to conform to the specification.

Documentation of all calibrations should include a description of the system "as found", details of any adjustments to the instrument, and a description of the system "as left"; this documentation is a vital part of the "paper-trail" for any claims of data validity. Calibrations are often confused with performance audits since both involve measuring the conformance of an instrument to a specification; the main difference has to do with the independence of the person performing the audit or calibration - the performance audit should be conducted by a person who is independent of the operating organization - calibrations, on the other hand, are often performed by individuals within the operating organization. Guidance specific to performance audits is provided in Section 8.4.

The guidance provided on calibration procedures in the following applies to in situ meteorological sensors such as would be mounted on a tower (e.g., wind vanes and anemometers) or located at ground level (e.g., a solar radiation sensor). Ideally, a calibration should be performed in an environment as close as possible to laboratory bench-test as conditions allow. For tower mounted sensors this usually involves removing the sensor from tower. The alternative to a bench-test calibration of the in situ sensor is a calibration using a collocated transfer standard; this involves locating an identical standard instrument as close as practical to the instrument being calibrated. The collocated standard transfer method is the most complete calibration/audit method from the standpoint of assessing total system error. However it has two serious drawbacks: 1) it is limited to the conditions that prevailed during the calibration/audit, and 2) it is sensitive to siting and exposure bias.

Calibrations using a bench test or collocated transfer standard are not generally applicable to the upper-air measurement systems; the special procedures required for calibrations and audits of upper-air measurement systems are discussed in Section 9.

Documentation supplied with newly purchased instruments should include the manufacturer's recommended calibration procedures. The guidance on calibration procedures provided in the following is intended to supplement the manufacturer's recommendations; when in doubt, the instrument manufacturer should be consulted.

8.3.1 Sensor Check

There are three types of action which can be considered a sensor check. First, one can look at and perform "housekeeping" services for the sensors. Secondly, one can measure some attribute of the sensor to detect deterioration in anticipation of preventative maintenance. Thirdly, the sensor can be subjected to a known condition whose consequence is predictable through the entire measurement system, including the sensor transducer. Each of these will be addressed for each variable, where appropriate, within the divisions of physical inspection and measurement and accuracy check with known input.

8.3.1.1 Physical inspection

The first level of inspection is visual. The anemometer and vane can be looked at, either directly or through binoculars or a telescope, to check for physical damage or signs of erratic behavior. Temperature shields can be checked for cleanliness. Precipitation gauges can be inspected for foreign matter which might effect performance. The static port for the atmospheric pressure system also can be examined for foreign matter. Solar radiation sensors should be wiped clean at every opportunity.

A better level of physical inspection is a "hands on" check. An experienced technician can feel the condition of the anemometer bearing assembly and know whether or not they are in good condition. This is best done with the aerodynamic shape (cup wheel, propeller, or vane) removed. Caution: Damage to anemometers and vanes is more likely to result from human handling than from the forces of the wind, especially during removal or installation and transport up and down a tower. The proper level of aspiration through a forced aspiration shield can be felt and heard under calm condition.

The best level of sensor check is a measurement. The anemometer and wind vane sensors have bearings which will certainly degrade in time. The goal is to change the bearings or the sensors before the instrument falls below operating specifications. Measurements of starting torque will provide the objective data upon which maintenance decisions can be made and defended. The presence, in routine calibration reports, of starting torque measurements will support the claim for valid data, if the values are less than the replacement torques.

The anemometer, identified by the serial number of the aerodynamic shape, should have a wind tunnel calibration report (see Section 8.1) in a permanent record folder. This is the authority for the transfer function (rate of rotation to wind speed) to be used in the next section. The temperature transducers, identified by serial number, should have calibration reports showing their conformity for at least three points to their generic transfer function (resistance to temperature, usually). These reports should specify the instruments used for the calibration and the method by which the instruments are tied to national standards (NBS). The less important sensors for solar radiation and atmospheric pressure can be qualified during an audit for accuracy.

8.3.1.2 Accuracy check with known input

Two simple tests will determine the condition of the anemometer (assuming no damage is found by the physical inspection). The aerodynamic shape must be removed. The shaft is driven at three known rates of rotation. The rates are known by independently counting shaft revolutions over a measured period of time in synchronization with the measurement system timing. The rates should be meaningful such as the equivalent of 2 m/s, 5 m/s and 10 m/s. Conversion of rates of rotation to wind speed is done with the manufacturer's transfer function or wind tunnel data. For example, if the transfer function is m/s = 1.412 r/s + 0.223, then rates of rotation of 1.3, 3.4 and 6.9 revolutions per second (r/s) would be equivalent to about 2, 5 and 10 m/s. All that is being tested is the implementation of the transfer function by the measuring system. The output should agree within one increment of resolution (probably 0.1 m/s). If problems are found, they might be in the transducer, although failures there are usually catastrophic. The likely source of trouble is the measurement system (signal conditioner, transmitting system, averaging system and recording system).

The second test is for starting torque. This test requires a torque watch or similar device capable of measuring in the range of 0.1 to 10 gm-cm depending upon the specifications provided by the manufacturer.

A successful response to these two tests will document the fact that the anemometer is operating as well as it did at receiving inspection, having verified threshold and accuracy. Changes in distance constant are not likely unless the anemometer design has changed. If a plastic cup is replaced by a stainless steel cup, for example, both the transfer function and the distance constant will likely be different. The distance constant will vary as the inverse of the air density. If a sea-level distance constant is 3.0 m, it may increase to 3.5 m in Denver and 4.3 m at the mountain passes in the Rockies.

For wind direction, a fixture holding the vane, or vane substitute, in positions with a known angle change is a fundamental challenge to the relative accuracy of the wind vane. With this method, applying the appropriate strategy for 360 or 540 degree systems, the accuracy of the sensor can be documented. The accuracy of the wind direction measurement, however, also depends on the orientation of the sensor with respect to true north.

The bearing to distant objects may be determined by several methods. The recommended method employs a solar observation (see Reference 3, p.11) to find the true north-south line where it passes through the sensor mounting location. Simple azimuth sighting devices can be used to find the bearing of some distant object with respect to the north-south line. The "as found" and "as left" orientation readings should report the direction to or from that distant object. The object should be one toward which the vane can be easily aimed and not likely to become hidden by vegetation or construction.

There are two parts of most direction vanes which wear out. One part is the bearing assembly and the other is the transducer, usually a potentiometer. Both contribute to the starting torque and hence the threshold of the sensor. A starting torque measurement will document the degradation of the threshold and flag the need for preventive maintenance. An analog voltmeter or oscilloscope is required to see the noise level of a potentiometer. Transducer noise may not be a serious problem with average values but it is likely to have a profound effect on σ_A.

The dynamic performance characteristics of a wind vane are best measured with a wind tunnel test. A generic test of a design sample is adequate. As with the anemometer, the dynamic response characteristics (threshold, delay distance and damping ratio) are density dependent.

Temperature transducers are reasonably stable, but they may drift with time. The known input for a temperature transducer is a stable thermal mass whose temperature is known by a standard transducer. The ideal thermal mass is one with a time constant on the order of an hour in which there are no thermal sources or sinks to establish local gradients within the mass. It is far more important to know what a mass temperature is than to be able to set a mass to a particular temperature.

For temperature difference systems, the immersion of all transducers in a single mass as described above will provide a zero-difference challenge accurate to about 0.01 °C. When this test is repeated with the mass at two more temperatures, the transducers will have been challenged with respect to how well they are matched and how well they follow the generic transfer function. Mass temperatures in the ranges of 0 to 10 °C, 15 to 25 °C, and 30 to 40 °C are recommended. A maximum difference among the three temperatures (i.e., 0, 20, and 40 °C) is optimum. Once the match has been verified, known resistances can be substituted for the transducers representing temperatures, according to the generic transfer function, selected to produce known temperature difference signals to the signal conditioning circuitry. This known input will challenge the circuitry for the differential measurement.

Precipitation sensors can be challenged by inserting a measured amount of water, at various reasonable rainfall rates such as 25 mm or less per hour. The area of the collector can be measured to calculate the amount of equivalent rainfall which was inserted. The total challenge should be sufficient to verify a 10% accuracy in measurement of water. This does not provide information about errors from siting problems or wind effects.

Dew point temperature (or relative humidity), atmospheric pressure and radiation are most simply challenged in an ambient condition with a collocated transfer standard. An Assmann psychrometer may be used for dew point. An aneroid barometer checked against a local National Weather Service instrument is recommended for atmospheric pressure. Another radiation sensor with some pedigree or manufacturer's certification may be used for pyranometers and net radiometers. A complete opaque cover will provide a zero check.

8.3.2 Signal Conditioner and Recorder Check

For routine calibration of measurement circuits and recorders, use the manufacturer's recommendations. The outputs required by the test described in 8.3.1.2 must be reflected in the recorded values. Wind speed is used as an example in this section. Other variables will have different units and different sensitivities but the principle is the same. For sub-system checks, use the manual for specific guidance.

8.3.2.1 Analog system

Some systems contain "calibration" switches which are designed to test the stability of the circuits and to provide a basis for adjustment if changes occur. These should certainly be exercised during routine calibrations when data loss is expected because of calibration. In the hierarchy of calibrations, wind tunnel is first, known rate of rotation is second, substitute frequency is third and substitute voltage is fourth. The "calibration" switch is either third or fourth.

If analog strip chart recorders are used, they should be treated as separate but vital parts of the measurement system. They simply convert voltage or current to a mark on a time scale printed on a continuous strip of paper or composite material. The output voltage or current of the signal conditioner must be measured with a calibrated meter during the rate of rotation challenge. A simple transfer function, such as 10 m/s per volt, will provide verification of the measurement circuit at the output voltage position. The recorder can be challenged separately by inputting known voltages and reading the mark on the scale, or by noting the mark position when the rate of rotation and output voltage are both known. See the recorder manual for recommendations should problems arise.

This special concern with recorders results from the variety of problems which analog recorders can introduce. A good measurement system can be degraded by an inappropriate recorder selection. If resolution is inadequate to distinguish between 1.3 m/s and 1.5 m/s, a 0.2 m/s accuracy is impossible. If enough resolution is just barely there, changes in paper as a function of relative humidity and changes in paper position as it passes the marking pen and excessive pen weight on the paper can be the limit of accuracy in the measurement. If the strip chart recorder is used only as a monitor and not as a backup for the primary system, its accuracy is of much less importance. The recorder from which data are recovered for archiving is the only recorder subject to measurement accuracy specifications.

8.3.2.2 Digital system

A digital system may also present a variety of concerns to the calibration method. One extreme is the digital system which counts revolutions or pulses directly from the sensor. No signal conditioning is used. All that happens is controlled by the software of the digital system and the capability of its input hardware to detect sensor pulses and only sensor pulses. The same challenge as described in 8.3.1.2 is used. The transfer function used to change rate of rotation to m/s should be found in the digital software and found to be the same as specified by the manufacturer or wind tunnel test. If any difference is found between the speed calculated from the known number of revolutions in the synchronous time period and the speed recorded in the digital recorder, a pulse detection problem is certain. A receiving inspection test may not uncover interference pulses which exist at the measurement site. For solution of this type of problem, see the digital recorder manufacturer's manual or recommendations.

A digital data logger may present different concerns. It may be a device which samples voltages, averages them, and transfers the average to a memory peripheral, either at the site or at the end of a communication link. Conversion to engineering units may occur at almost any point. The routine calibration should look at the output voltage of a signal conditioner as a primary point to assess accuracy of measurement. Analog to digital conversion, averaging and transmission and storage would be expected to degrade the measurement accuracy very little. Such functions should contribute less than 0.05 m/s uncertainty from a voltage input to a stored average value. If greater errors are found when comparing known rates of rotation and known signal conditioning output voltages to stored average wind speed values, check the data logger manual for specifications and trouble-shooting recommendations.

8.3.3 Calibration Data Logs

Site log books must record at least the following:

- Date and time of the calibration period (no valid data)
- Name of calibration person or team members

- Calibration method used (this should identify SOP number and data sheet used)
- Where the data sheet or sheets can be found on site
- Action taken and/or recommended

The data sheet should contain this same information along with the measurement values found and observations made. Model and serial numbers of equipment tested and used for testing must appear. The original report should always be found at the site location and a copy can be used for reports to management (a single-copy carbon form could be used). The truism that "it is impossible to have too many field notes" should be underscored in all training classes for operators and auditors.

8.3.4 Calibration Report

The calibration report may be as simple as copies of the calibration forms with a cover page, summary and recommendations. While the calibration forms kept at the site provide the basis for the operator or the auditor to trace the performance of the instrument system, the copies which become a part of the calibration report provide the basis for management action should such be necessary. The calibration report should travel from the person making out the report through the meteorologist responsible for the determination of data validity to the management person responsible for the project. Any problem should be highlighted with an action recommendation and a schedule for correction. As soon as the responsible management person sees this report the responsibility for correction moves to management, where budget control usually resides. A signature block should be used to document the flow of this information.

8.3.5 Calibration Schedule/Frequency

System calibration and diagnostic checks should be performed at six month intervals, or in accordance with manufacturer's recommendations, whichever is more frequent. The risk of losing data increases with the interval between operational checks. To reduce this risk, routine operational checks should be performed on a daily basis; these daily checks may be performed remotely. On-site inspections and maintenance should be performed on a weekly basis.

8.3.6 Data Correction Based on Calibration Results

Corrections to the raw data are to be avoided. A thorough documentation of an error clearly defined may result in the correction of data (permanently flagged as corrected). For example, if an operator changes the transfer function in a digital logger program and it is subtle enough not to be detected in the quality control inspection of the data stream, but is found at the next calibration, the data may be corrected. The correction can be calculated from the erroneous transfer function and applied to the period starting when the logger program was changed (determined by some objective method such as a log entry) and ending when the error was found and corrected.

Another example might be a damaged anemometer cup or propeller. If an analysis of the data points to the time when the damage occurred, a correction period can be determined. A wind tunnel test will be required to find a new transfer function for the damaged cup or propeller assembly. With the new transfer function defining the true speed responsible for a rate of rotation, and with the assumption that the average period is correctly represented by a steady rate of rotation, a correction can be made and flagged. This is a more risky example and judgment is required since the new transfer function may be grossly different and perhaps non-linear.

8.4 Audits

The audit function has two components, the system audit (in essence, a challenge to the QAPP) and the performance audit (a challenge to the individual measurement systems).

The system audit provides an overall assessment of the commitment to data validity; as such, all commitments made in the QAPP should be subject to challenge. Typical questions asked in the systems audit include: "are standard operating procedures being followed?", "is the station log complete and up-to-date?" All deficiencies should be recorded in the audit report along with an assessment of the likely effect on data quality. Corrective actions related to a systems audit should be obvious if the appropriate questions are asked.

The performance audit is similar to a calibration in terms of the types of activities performed (Section 8.3) - all the performance audit adds is an independent assurance that the calibrations are done correctly and that the documentation is complete and accurate. In the ideal case, when both the auditor and site operator are equally knowledgeable, the auditor functions as an observer while the site operator performs the calibration; in this instance the auditor functions in a "hands-off" mode. In initial audits, since newly hired site operators may have little or no experience with meteorological instruments, the hands-off approach may not be practical or desirable. In these instances, the audit may also function as a training exercise for the site operator.

8.4.1 Audit Schedule and Frequency

An initial audit should be performed within 30 days of the start-up date for the monitoring program. The 30-day period is a compromise between the need for early detection and correction of deficiencies and the time needed for shake-down and training. Follow-up audits should be conducted at six-month intervals.

8.4.2 Audit Procedure

To ensure against conflicts of interest, all audits should be conducted by individuals who are independent of the organizations responsible for the monitoring and/or using the data. This is especially important as the audit will be essential in any legal claims related to data validity. The audit should begin with a briefing stating the goals of the audit and the procedures to be employed - in addition, if any assistance is needed (e.g., in removing a wind vane from a tower) this would be the time to arrange such with the site technicians. An exit interview should be conducted when the audit is finished; management from the organizations involved should be present at both the initial briefing and the exit interview.

8.4.3 Corrective Action and Reporting

A corrective action program is an essential management tool for coordination of the QAQC process. Activities associated with the corrective action program include: review of procedures for reporting deficiencies, problem tracking, planning and implementing measures to correct problems, and tracking of problem resolution. Documentation of corrective actions is included with other information in support of data validity. A sample form for documenting corrective actions can be found in reference **[65]**.

An audit report should be completed and submitted within 30 days of the audit performance. This is an important document in that it provides a basis for any legal claims to data validity. As such, care should be taken to ensure that all statements related to data validity are supportable. Where possible the report should contain copies of the forms used in the audit.

8.5 Routine and Preventive Maintenance

Data quality is dependent on the care taken in routine and preventative maintenance. These functions are the responsibility of the site technicians; given their important QAQC role, they should be fully trained to maintain the equipment. The training program for the site technicians should be addressed in the QAPP. The following additional information on maintenance should also be included in the QAPP:

- A list the site technicians and their alternates
- Procedures and checklists for preventive maintenance
- Schedule for preventive maintenance
- Procedures for maintaining spare components
- A list of the components to be checked and/or replaced

Checklists are an essential component of a routine maintenance program and should be used as a matter of course. The instrument manuals should be used as the starting point for the checklist for each of instruments - a good manual should indicate what components need to be checked and how often. A station checklist should also be developed; this should include the following:

- A List of safety and emergency equipment.
- List of items to be inspected following severe weather.
- A checkoff to ensure there is adequate disk space for on-site storage of the raw data.

- A checkoff to indicate that backup of data has been completed.
- A checkoff to indicate that clocks have been checked and adjusted as necessary.
- A checkoff for the cables and guy wires securing the equipment.

All routine and preventive maintenance activities should be recorded in the station log and/or on the appropriate checklist. The station log and checklist provide the necessary paper trail to support claims of accuracy.

8.5.1 Standard Operating Procedures

Standard operating procedures (SOPs) should be developed that are specific to the operations at a given site. The purpose of an SOP is to spell out operating and QC procedures with the ultimate goal of maximizing data quality and data capture rates. Operations should be performed according to a set of well defined, written SOPs with all actions documented in logs and on prepared forms. SOPs should be written in such a way that if problems are encountered, instructions are provided on actions to be taken. At a minimum, SOPs should address the following:

- Installation, setup, and checkout
- Site operations and calibrations
- Operational checks and preventive maintenance
- Data collection protocols
- Data validation steps
- Data archiving

8.5.2 Preventive Maintenance

8.5.2.1 Wind Speed

The anemometer has just one mechanical system which will benefit from preventive maintenance. That is the bearing assembly. There are two strategies from which to choose. One is to change the bearings (or the entire instrument if a spare is kept for that purpose) on a scheduled basis and the other is to make the change when torque measurements suggest change is in order. The former is most conservative with respect to data quality assuming that any time a torque measurement indicates a bearing problem, the bearing will be changed as a corrective maintenance action.

As routine calibrations become less frequent (8.3.5), the probability increases that a starting torque measurement will be made which indicates the anemometer is outside its performance specification. This will effect both the threshold (by increasing it) and the transfer function (by moving the non-linear threshold toward high speeds). It is unlikely that corrections can be properly made to the data in this case. The consequence might be the loss of a half-year's data, if that is the period for routine calibration. If experience indicates that the anemometer bearing assembly shows serious wear at the end of one year or two years (based on torque measurements), a routine change of bearings at that frequency is recommended.

8.5.2.2 Wind Direction

The wind vane usually has two mechanical systems which will benefit from preventive maintenance. The bearing assembly is one and can be considered in the same way as the anemometer bearing assembly described above. The other is the potentiometer which will certainly "wear out" in time. The usual mode of failure for a potentiometer is to become noisy for certain directions and then inoperative. The noisy stage may not be apparent in the average direction data. If σ_A is calculated, the noise will bias the value toward a higher value. It will probably not be possible to see early appearance of noise in the σ_A data. When it becomes obvious that the σ_A is too high, some biased data may already have been validated and archived. Systems with time constant circuits built into the direction output will both mask the noise from the potentiometer (adding to the apparent potentiometer life) and bias the σ_A toward a lower value. Such circuits should not be used if they influence the actual output capability of the sensor. Each manufacturer may be different in their selection of a source and specifications used in buying potentiometers. The operator needs to get an expected life for the potentiometer from the manufacturer and monitor the real life with a noise sensitive test. An oscilloscope is best and can be used without disrupting the measurement. When potentiometer life expectations have been established, a preventive maintenance replacement on a conservative time basis is recommended.

8.5.2.3 Temperature and Temperature Difference

Aspirated radiation shields use fans which will also fail in time. The period of this failure should be several years. The temperature error resulting from this failure will be easily detected by a QC meteorologist inspecting the data. Some aspirated radiation shields include an air flow monitoring device or a current check which will immediately signal a disruption in aspiration. Preventive maintenance is not required but spare fans should be on the shelf so that a change can be made quickly when failure does occur.

8.5.2.4 Dew Point Temperature

Field calibration checks of the dew point temperature measurement system can be made with a high-quality Assmann-type or portable, motor-aspirated psychrometer. Sling psychrometers should not be used. Several readings should be taken at the intake of the aspirator or shield at night or under cloudy conditions during the day. These field checks should be made at least monthly, or in accordance with manufacturer's suggestions, and should cover a range of relative humidity values.

Periodically (at least quarterly) the lithium chloride in dew cells should be removed and recharged with a fresh solution. The sensor should be field-checked as described above before and at least an hour after the lithium chloride solution replacement.

If cooled-mirror type dew point systems are used, follow the manufacturer's service suggestions initially. The quality of the data from this method of measurement is dependent upon the mirror being kept clean. The frequency of service required to keep the mirror clean is a function of the environment in which the sensor is installed. That environment may vary with seasons or external weather conditions. If changes in dew point temperature of a magnitude larger than can be tolerated are found after service scheduled according to the manufacturer's suggestion, increase the service frequency until the cleaning becomes preventive maintenance rather than corrective service. This period will vary and can be defined only by experience. Station log data must include the "as found" and the "as left" measurements. Dew point temperature does not change rapidly (in the absence of local sources of water) and the difference between the two measurements will usually be the instrument error due to a dirty mirror.

8.5.2.5 Precipitation

The gauge should be inspected at regular intervals using a bubble level to see that the instrument base is mounted level. Also, the bubble level should be placed across the funnel orifice to see that it is level. The wind screen should also be checked to see that it is level, and that it is located l/2 inch above the level of the orifice, with the orifice centered within the screen.

8.5.2.6 Pressure

The output of the pressure sensor should be regularly checked against a collocated instrument. A precision aneroid barometer can be used for this check. The collocated barometer should be occasionally checked against a mercurial barometer reading at a nearby NWS station.

8.5.2.7 Radiation

The optical hemispheres on pyranometers and net radiometers should be cleaned frequently (preferably daily) with a soft, lint-free cloth. The surfaces of the hemispheres should be regularly inspected for scratches or cracks. The detectors should be regularly inspected for any discoloration or deformation. The instruments should be inspected during cool temperatures for any condensation which may form on the interior of the optical surfaces.

While calibrations must be done by the manufacturer, radiation can be field-checked using a recently-calibrated, collocated instrument. Since signal processing is particularly critical for these sensors, the collocated instrument should also use its own signal conditioner and data recording system for the check. This kind of field check should be done every six months.

It is mandatory to log "as found" and "as left" information about the parts of the system which seem to require work. Without this information it becomes difficult, if not impossible, to assess what data are usable and what are not.

8.6 Data Validation and Reporting

Data validation is a process in which suspect data are identified and flagged for additional review and corrective action as necessary. The data validation process provides an additional level of quality assurance for the monitoring program. Some problems that may escape detection during an audit (e.g., a wind vane that occasionally gets stuck) are often easily identified during data validation.

Data validation should be performed by a person with appropriate training in meteorology who has a basic understanding of local meteorological conditions and the operating principles of the instruments.

8.6.1 Preparatory Steps

Preparatory steps prior to data validation include: collection and storage of the raw data, backup, data reduction, transfer of data off-site, and preliminary review. These steps are discussed in the following:

- Collection and storage on-site (as appropriate) of the "raw" signals from the sensors, followed by real-time processing of the "raw" data by the data acquisition system to produce reduced, averaged values of the meteorological variables. The reduced data are stored on the data acquisition system's computer, usually in one or more ASCII files.
- Transfer of the reduced data to a central data processing facility at regular intervals (e.g., daily). Once the data are received at the central facility, they should be reviewed by an experienced data technician as soon as possible to verify the operational readiness of the monitoring site. Backup copies of the data should be prepared and maintained on-site and off-site.

Data collected by the monitoring systems can usually be obtained by polling the data system at a site from the central facility using a personal computer, modem, and standard telecommunications software. Other options that are available for communications with a remote site include leased-line telephone service, local or wide area network (LAN, WAN) connections, Internet access, and satellite telemetry. For immediate turnaround of data, the operator can transfer the data to the central facility using a personal computer equipped with a modem and communications software.

8.6.2 Levels of Validation

A level of validation, for the purposes of this guidance, is a numeric code indicating the degree of confidence in the data. These levels provide some commonality among data collected and quality controlled by different agencies, and help ensure that all data have received a comparable level of validation. Various data validation "levels" that apply to air quality and meteorological data have been defined by Mueller and Watson **[66]** and Watson et al. **[67]**. Basically, four levels of data validation have been defined:

- **Level 0** data validation is essentially raw data obtained directly from the data acquisition systems in the field. Level 0 data have been reduced and possibly reformatted, but are unedited and unreviewed. These data have not received any adjustments for known biases or problems that may have been identified during preventive maintenance checks or audits. These data should be used to monitor the instrument operations on a frequent basis (e.g., daily), but should not be used for regulatory purposes until they receive at least Level 1 validation.
- **Level 1** data validation involves quantitative and qualitative reviews for accuracy, completeness, and internal consistency. Quantitative checks are performed by software screening programs (**see Section 8.7.3.2**) and qualitative checks are performed by meteorologists or trained personnel who manually review the data for outliers and problems. Quality control flags, consisting of numbers or letters, are assigned to each datum to indicate its quality. A list of suggested quality control codes is given in Table 8-3. Data are only considered at Level 1 after final audit reports have been issued and any adjustments, changes, or modifications to the data have been made.
- **Level 2** data validation involves comparisons with other independent data sets. This includes, for example, intercomparing collocated measurements or making comparisons with other upper-air measurement systems.
- **Level 3** validation involves a more detailed analysis when inconsistencies in analysis and modeling results are found to be caused by measurement errors.

8.6.3 Validation Procedures

All necessary supporting material, such as audit reports and any site logs, should be readily available for the level 1 validation. Access to a daily weather archive should be provided for use in relating suspect data with to local and regional meteorological conditions. Any problem data, such as data flagged in an audit, should be corrected prior to the level 1 data validation. The validation procedures described in the following include screening, manual review, and comparison.

Table 8-3

Suggested quality control (QC) codes for meteorological data.

Code	Meaning	Description
0	Valid	Observations that were judged accurate within the performance limits of the instrument.
1	Estimated	Observations that required additional processing because the original values were suspect, invalid, or missing. Estimated data may be computed from patterns or trends in the data (e.g., via interpolation), or they may be based on the meteorological judgment of the reviewer.
2	Calibration applied	Observations that were corrected using a known, measured quantity (e.g., instrument offsets measured during audits).
3	Unassigned	Reserved for future use.
4	Unassigned	Reserved for future use.
5	Unassigned	Reserved for future use.
6	Failed automatic QC check	Observations that were flagged with this QC code did not pass screening criteria set in automatic QC software.
7	Suspect	Observations that, in the judgment of the reviewer, were in error because their values violated reasonable physical criteria or did not exhibit reasonable consistency, but a specific cause of the problem was not identified (e.g., excessive wind shear in an adiabatic boundary layer). Additional review using other, independent data sets (Level 2 validation) should be performed to determine the final validity of suspect observations.
8	Invalid	Observations that were judged inaccurate or in error, and the cause of the inaccuracy or error was known (e.g., winds contaminated by ground clutter or a temperature lapse rate that exceeded the autoconvective lapse rate). Besides the QC flag signifying invalid data, the data values themselves should be assigned invalid indicators.
9	Missing	Observations that were not collected.

8.6.3.1 Data Screening

Screening procedures generally include comparisons of measured values to upper and lower limits; these may be physical limits, such as an instrument threshold, or may be established based on experience or historical data. Other types of procedures employed in screening include assessments based on the rate of change of a variable (in these data that change too rapidly or not at all are flagged as suspect) and assessments based on known physical principles relating two or more variables (e.g., the dew point should never exceed the dry-bulb temperature).

Screening may be regarded as an iterative process in which range checks and other screening criteria are revised as necessary based on experience. For example, an initial QA pass of a data set using default criteria may flag values which upon further investigation are determined to be valid for the particular site. In such cases, one or more follow-up QA passes using revised criteria may be necessary to clearly segregate valid and invalid data. Suggested screening criteria are listed in Table 8-4. Data which fail the screening test should be flagged for further investigation.

8.6.3.2 Manual Review

The manual review should result in a decision to accept or reject data flagged by the screening process. In addition, manual review may help to identify outliers that were missed by screening. This review should be performed by someone with the necessary training in meteorological monitoring.

In the typical manual review, data should be scanned to determine if the reported values are reasonable and in the proper format. Periods of missing data should be noted and investigated. Data should also be evaluated for temporal consistency. This is particularly useful for identifying outliers in hourly data. Outliers should be reviewed with reference to local meteorological conditions. Data are considered to be at Level 1 validation following the manual review and can be used for modeling and analysis.

8.6.3.3 Comparison Program

After the data have passed through the screening program, they should be evaluated in a comparison program. Randomly selected values should be manually compared with other available, reliable data (such as, data obtained from the nearest National Weather Service observing station). At least one hour out of every 10 days should be randomly selected. To account for hour-to-hour variability and the spatial displacement of the NWS station, a block of several hours may be more desirable. All data selected should be checked against corresponding measurements at the nearby station(s). In addition, monthly average values should be compared with climatological normals, as determined by the National Weather Service from records over a 30-year period. If discrepancies are found which can not be explained by the geographic difference in the measurement locations or by regional climatic variations, the data should be flagged as questionable.

Table 8-4

Suggested Data Screening Criteria

Variable	Screening Criteria: Flag data if the value
Wind Speed	- is less than zero or greater than 25 m/s
	- does not vary by more than 0.1 m/s for 3 consecutive hours
	- does not vary by more than 0.5 m/s for 12 consecutive hours
Wind Direction	- is less than zero or greater than 360 degrees
	- does not vary by more than 1 degree for more than 3 consecutive hours
	- does not vary by more than 10 degrees for 18 consecutive hours
Temperature	- is greater than the local record high
	- is less than the local record low
	(The above limits could be applied on a monthly basis.)
	- is greater than a 5°C change from the previous hour
	- does not vary by more than 0.5°C for 12 consecutive hours
Temperature Difference	- is greater than 0.1°C/m during the daytime
	- is less than -0.1°C/m during the night time
	- is greater than 5.0°C or less than -3.0°C
Dew Point Temperature	- is greater than the ambient temperature for the given time period
	- is greater than a 5°C change from the previous hour
	- does not vary by more than 0.5°C for 12 consecutive hours
	- equals the ambient temperature for 12 consecutive hours
Precipitation	- is greater than 25 mm in one hour
	- is greater than 100 mm in 24 hours
	- is less than 50 mm in three months
	(The above values can be adjusted based on local climate.)
Pressure	- is greater than 1060 mb (sea level)
	- is less than 940 mb (sea level)
	(The above values should be adjusted for elevations other than sea level.)
	- changes by more than 6 mb in three hours
Radiation	- is greater than zero at night
	- is greater than the maximum possible for the date and latitude

8.6.3.4 Further Evaluations

Any data which are flagged by the screening program or the comparison program should be evaluated by personnel with meteorological expertise. Decisions must be made to either accept the flagged data, or discard and replace it with back-up or interpolated data, or data from a nearby representative monitoring station (see Section 1). Any changes in the data due to the validation process should be documented as to the reasons for the change. If problems in the monitoring system are identified, corrective actions should also be documented. Any edited data should continue to be flagged so that its reliability can be considered in the interpretation of the results of any modeling analysis which employs the data.

8.6.4 Schedule and Reporting

Data should be retrieved on a daily basis and reviewed for reasonableness to ensure that the instrument is operating properly. Level 1 data validation should be performed as frequently as possible (e.g., bi-weekly or monthly). At a minimum, validation should be done weekly for the first month after the instrument is installed, so that any potential problems can be identified and quickly resolved to avoid significant data losses.

It is important to maintain detailed, accurate records of changes to the data and the data quality control codes. These records will save time and effort if questions arise about specific data at a later date. Reports should include the following information:

- Who performed the quality control validation, type of data validated, and when the validation was completed.
- Any adjustments, deletions, or modifications, with a justification or reason for the change.
- Identification of data points that were flagged as suspect or invalid, and the reason why they were flagged.
- Systematic problems that affected the data.

8.7 Recommendations

Quality Assurance/Quality Control (QAQC) procedures should be documented in a Quality Assurance Project Plan (QAPP) and approved by the appropriate project or organizational authority. These procedures should provide quantitative documentation to support claims of accuracy and should be conducted by persons independent of the organization responsible for the collection of the data and the maintenance of the measurement systems.

Procurement documents for meteorological monitoring systems should include the specifications for instrument systems and should identify the test method by which conformance with the specification will be determined. Persons responsible installing meteorological systems should review documentation provided on conformance-testing and should conduct independent *acceptance tests to verify claims of accuracy. All acceptance-testing activities should be documented in the station log.*

Routine system calibrations and system audits should be performed at the initiation of a monitoring program (within 30 days of start-up) and at least every six months thereafter. More frequent calibrations and audits may be needed in the early stages of the program if problems are encountered, or if valid data retrieval rates are unacceptably low. Documentation of all calibrations should include a description of the system "as found", details of any adjustments to the instrument, and a description of the system "as left"; this documentation is necessary for any claims of data validity.

Regular and frequent routine operational checks of the monitoring system are essential to ensuring high data retrieval rates. These should include visual inspections of the instruments for signs of damage or wear, inspections of recording devices to ensure correct operation and periodic preventive maintenance. The latter should include periodic checks of wind speed and wind direction bearing assemblies, cleaning of aspirated shield screens in temperature systems, removal and recharging (at least quarterly) of lithium chloride dew cells, cleaning of the mirror in cooled mirror dew cells, clearing the precipitation gauge funnel of obstructing debris, and frequent (preferably daily) cleaning of the optical surface of a pyranometer or net radiometer. Also crucial to achieving acceptable valid data retrieval rates is the regular review of the data by an experienced meteorologist. This review should include visual scanning of the data, and automated screening and comparison checks to flag suspect data. This review should be performed weekly, and preferably on a daily basis.

9. UPPER-AIR MONITORING

This section provides guidance for the most widely used technologies employed for monitoring upper-air meteorological conditions; these include radiosondes and ground-based remote sensing platforms: sodar (Sound Detection and Ranging), radar (Radio Detection and Ranging), and RASS (Radio Acoustic Sounding System). While they are not covered in detail, other (emerging) technologies such as lidar (Light Detection and Ranging) may provide alternative means for the collection of upper-air meteorological data.

The material is organized such that information necessary to the understanding of the technology (Sections 9.1 through 9.3) precedes the guidance (Sections 9.4 through 9.7). The sections are as follows: Section 9.1 provides information necessary to the understanding of balloon-based sounding instruments and ground-based remote sensing technologies. Section 9.2 provides information on the performance characteristics of these systems; Section 9.3 discusses monitoring objectives and goals for monitoring of the boundary layer in support of air quality dispersion modeling; Section 9.4 provides guidance on siting and exposure of upper-air monitoring systems; Section 9.5 provides guidance on installation and acceptance testing; Section 9.6 provides guidance on quality assurance; and Section 9.7 provides guidance for data processing and management.

9.1 Fundamentals

Table 9-1 provides an overview of the upper-air monitoring systems included in this guidance. Necessary details describing the operation of each of the monitoring platforms [Radiosonde (9.1.2), Doppler Sodar (9.1.3), Radar Wind Profiler (9.1.4), and RASS (9.1.5)] is preceded by a description of the various meteorological variables that are measured by, or derived from measurements obtained with these platforms

9.1.1 Upper-Air Meteorological Variables

Meteorological variables measured/reported in upper-air monitoring programs include wind direction, wind speed, pressure, temperature, and humidity. With some exceptions (e.g., radiosonde measurements of pressure, temperature, and humidity), the upper-air data for these variables are based on indirect measurements; i.e., the desired variable is derived from measurements of other variables which are measured directly. This is a significant difference from the in situ measurements of these variables; i.e., when monitored in situ (such as from a meteorological tower) these variables are measured directly. This difference has significant implications for calibrations and audits of upper-air measurement systems (see Section 9.6).

Fundamentals related to upper-air monitoring of wind, pressure, temperature, and humidity are presented in the following. This is followed by information on estimating mixing heights and stability for use in dispersion modeling. Although the latter are often included in discussions of upper-air meteorological conditions, they are not really upper-air variables; a more accurate classification of mixing height would describe it as a boundary layer variable which can be derived from upper-air measurements. Stability, as defined for use in dispersion modeling, is a surface layer variable and is not necessarily related to or correlated with upper-air measurements.

Wind Upper-air wind speeds and wind directions are vector-averaged measurements. None of the measurement systems described in the following sections provide a means to measure winds as scaler quantities, as is done with cup and vane sensors mounted on an instrumented tower. While tower-based measurements near the surface are easily obtained, there are very few instrumented tall towers that can provide vertical profiles of upper-air winds over the altitudes needed for some air quality applications.

Upper-air wind data comprise either path averages (radiosondes) or volume averages (remote sensors) rather than point measurements. For air quality programs, where the interest is mainly to characterize winds in the atmospheric boundary layer (ABL) and lower troposphere, radiosonde data are typically averaged over vertical layers with a depth of approximately 45 to 75 meters (m). Wind data provided by sodars are typically averaged over layers that are 5 to 100 m deep, while radar wind profiler data are usually averaged over 60 to 100 meter intervals. The altitude at which the winds are reported is assumed to be the mid-point of the layer over which the winds are averaged. Averaging periods for upper-air wind data also vary depending on the instrument system used. An individual wind data report from a radiosonde sounding system is typically averaged over no more than 30 to 120 seconds, representing averages of 60 to 700 meters. The averaging interval for winds measured by sodars and radar profilers is usually on the order of 15 to 60 minutes.

Upper-air wind data are needed to accurately characterize upper-air transport. For example, observing and resolving the vertical shear of the horizontal wind (both speed and directional changes with height) can be important for air quality model applications. Figure 9-1 shows a plot of upper-air winds measured by a radiosonde sounding system, along with simultaneous profiles of temperature, dew-point temperature, and potential temperature. The wind data are represented in the “wind barb” format, in which the direction of the wind is indicated by the orientation of an arrow's shaft (relative to true north, which is toward the top of the figure), and the wind speed is indicated by the number and length of barbs attached to the shaft. Note the change in wind speed and direction that is evident in the first few hundred meters of the sounding. In this case, below about 280 meters the winds are east-southeasterly. Above this level the winds veer (turn clockwise) with height to become southerly, southwesterly, then westerly. This is a simple example of a pattern that is common in upper-air measurements; in fact, much more complex wind shear conditions are often observed. Wind shear conditions can have important implications with respect to air quality, because of the different transport and turbulence conditions that can exist at different altitudes where air pollutants may be present.

Shear patterns such as those depicted in Figure 9-1 occur in part because of the frictional drag exerted on the atmosphere by the earth's surface. The atmospheric boundary layer is generally defined as the layer of the atmosphere within which the dynamic properties (i.e., winds) and thermodynamic properties (i.e., temperature, pressure, moisture) are directly influenced by the earth's surface. Factors that influence the vertical distribution of winds include horizontal gradients in temperature (thermal wind effects), the development of local temperature and pressure gradients in shoreline settings (land/sea-breeze circulations) and complex terrain environments (mountain-valley airflows), vertical momentum transport by turbulent eddies, and diurnal reductions in frictional stress at night that can lead to the formation of low-level jets. Processes such as these are described in references **[68]** and **[69]**; examples of the effects of such circulations on air quality are described in reference **[70]**.

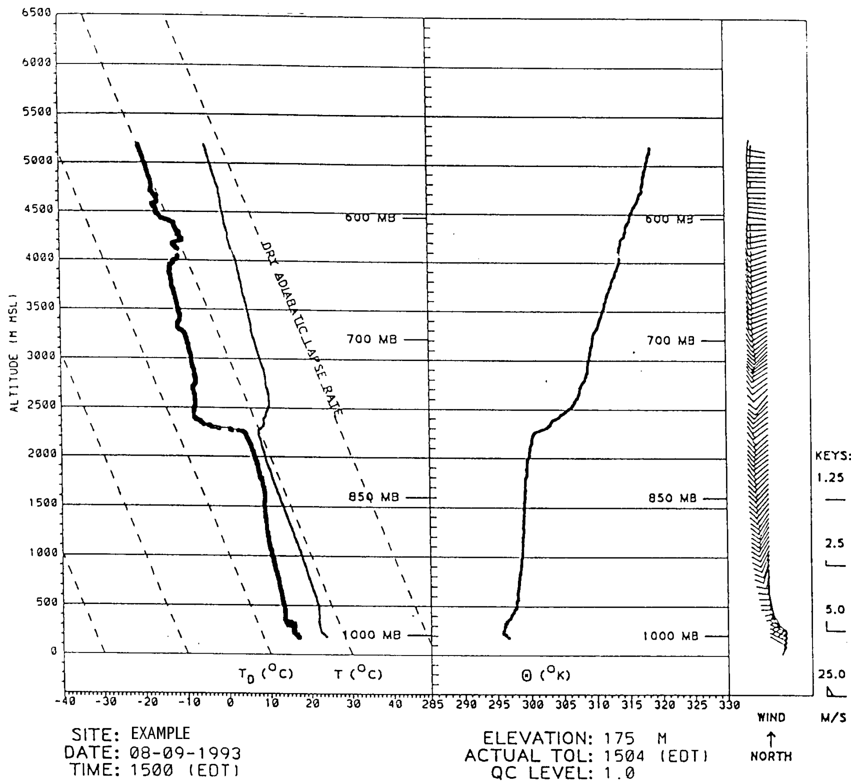

Figure 9-1 Example wind and temperature profiles from a radiosonde sounding system.

Consequently, upper-air wind data are critical to air quality analysis and modeling efforts. The data are used for the assessment of transport characteristics, as direct input to Gaussian dispersion models, and in the initialization and application of meteorological models (that are used to prepare time-varying, three-dimensional meteorological fields for puff and grid-based air quality models).

Upper-air wind speeds are almost always reported in units of meters per second (ms^{-1}) or knots (nautical miles per hour). Wind direction is reported as the direction from which the wind is blowing in degrees (clockwise) relative to true north. Altitude is usually reported in meters or feet and must be defined as corresponding to height above mean sea level or height above ground level. Radiosonde data are typically reported as height above mean sea level (msl), whereas wind data collected by the remote sensing systems are often reported as height above ground level (agl).

Some remote sensing systems described in these guidelines provide a measure of vertical velocity. To date, however, little use has been made of these data in air quality modeling or data analysis applications. Additional work is needed (possibly on a case-by-case basis) to determine the utility of these data for air quality applications.

Pressure Vertical profiles of atmospheric pressure are measured during radiosonde ascents. The remote sensing systems considered in this document do not measure pressure. Pressure data are critical for radiosonde soundings because they are used to calculate the altitude of the sonde (strictly speaking, the geopotential altitude). Differential global position systems (GPS) rawinsonde systems are being developed that will be able to measure the altitude of the sonde directly, but pressure data will still be needed to support many modeling and data analysis efforts. For air quality purposes, pressure data are used in the application of meteorological models, and as direct input to air quality models. Pressure is reported in units of millibars (mb) or hectopascals (hPa).

Temperature Upper-air temperature measurements are most commonly obtained using radiosonde sounding systems. Radiosonde temperature measurements are point measurements. These can be obtained every few seconds, yielding a vertical resolution of a few meters to about 10 m, depending on the rate of ascent of the balloon.

Temperature data can also be obtained using RASS. RASS temperature measurements are volume averages, with a vertical resolution comparable to that of the wind measurements reported by the remote sensing systems (i.e., 50 to 100 m). RASS measures the virtual temperature (T_v) of the air rather than the dry-bulb temperature (T). The virtual temperature of an air parcel is the temperature that dry air would have if its pressure and density were equal to those of a parcel of moist air, and thus T_v is always higher than the dry-bulb temperature. Under hot and humid conditions, the difference between T_v and T is usually on the order of a few (2 to 3) degrees C; at low humidity, differences between T_v and T are small. Given representative moisture and pressure profiles, temperature can be estimated from the virtual temperature measurements.

Temperature data are used widely in air quality analysis and modeling, including the application and evaluation of meteorological models, and as direct input to air quality models. The vertical temperature structure (stability) influences plume rise and expansion and thus the vertical exchange of pollutants. Temperature also affects photolysis and chemical reaction rates. Temperature is reported in degrees Celsius ($^\circ$C) or Kelvins (K).

Moisture Like pressure, upper-air moisture measurements suitable for air quality applications are primarily obtained using radiosonde sounding systems. The sampling frequency and vertical and temporal resolution of the moisture data are the same as the other thermodynamic variables measured by these systems. Moisture is most commonly measured directly as relative humidity (RH), and is reported as percent RH or as dew-point temperature (T_d) in $^\circ$C (or frost point temperature). Dew-point depression, the difference between temperature and dew-point temperature ($T - T_d$), is also a commonly reported variable. Some radiosonde sounding systems measure the wet-bulb temperature instead, and determine RH and dew-point temperature through the psychrometric relationship.

Upper-air moisture profiles are used in the initialization and application of meteorological models, and as direct input to air quality models. Moisture data can be important to a successful meteorological modeling effort, because the accurate simulation of convective development (clouds, precipitation, etc.) depends on an accurate representation of the three-dimensional moisture field. Upper-air moisture data are also useful to the understanding of the formation and growth of aerosols, which grow rapidly at high relative humidity (90 to 100 percent).

Mixing Height For the purposes of this guidance, mixing height is defined as the height of the layer adjacent to the ground over which an emitted or entrained inert non-buoyant tracer will be mixed (by turbulence) within a time scale of about one hour or less (adapted from Beyrich **[43]** . This concept of a mixing height was first developed for characterizing dispersion in a daytime convective boundary layer (CBL). Since tracer measurements are impractical for routine application, alternative methods are recommended for estimating mixing heights based on more readily available data (Table 9-2). The Holzworth method **[44]** is recommended for use when representative NWS upper-air data are available. This procedure relies on the general theoretical principle that the lapse rate is roughly dry adiabatic (no change in potential temperature with height) in a well-mixed daytime convective boundary layer (CBL); the Holzworth method is described in Section 6.5.1. Other alternatives include using estimates of mixing heights provided in CBL model output (references **[45]** and **[46]**). Mixing heights derived from remote sensing measurements of turbulence or turbulence related parameters are discussed in the following.

Turbulence, or turbulence related measurements (e.g, backscatter measurements from a sodar or refractive index measurements from a radar wind profiler) though not surrogates for an inert tracer can sometimes be used to estimate mixing heights since, under certain conditions, such measurements correlate with the top of the mixed layer. In looking at these measurements, one attempts to determine depth of the layer adjacent to the surface within which there is continuous or intermittent turbulence; this is a non-trivial exercise since turbulence varies considerably, not only with height, but with time and location. This variability is dependent upon which processes control/dominate the production of turbulence near the surface; these processes are discussed in the following.

The production of turbulent eddies during the daytime is dominated (under clear sky conditions) by heating of the ground surface and (under overcast conditions) by frictional drag. Daytime vertical mixing processes can be vigorous (especially under convective -conditions) and can produce a well mixed or nearly uniform vertical concentration profile of an inert tracer. During the nighttime, there are several processes that contribute to the production of turbulence including wind shear (created near the ground by friction), variations in the geostrophic wind, and the presence of a low-level jet (wind shear both below and above the jet can enhance turbulence). Nighttime vertical mixing processes are typically patchy and intermittent, and not capable of producing a well-mixed uniform vertical concentration profile.

Table 9-2

Methods for Determining Mixing Heights

Platform	Variable Measured	Advantages/limitations
Aircraft LIDAR	Inert tracer	Consistent with the definition of mixing height as used in dispersion modeling. Labor intensive, not practical for routine applications.
Rawinsonde	Potential temperature	A relatively robust technique for estimating the daytime (convective) mixing depth. Limited by the non-continuous nature of rawinsonde launches.
Sodar	Turbulence Acoustic backscatter	Used for continuous monitoring of boundary layer conditions. The range of a sodar, however, is limited; estimates of the mixing height are possible only when the top of the mixed layer is within the range of the sodar. A good tool for monitoring the nocturnal, surface-based temperature inversion - although different from the mixing height, the nocturnal inversion is equally important for modeling nocturnal dispersion conditions.
Radar wind profiler	Refractive index	Used for continuous monitoring of boundary layer conditions.
RASS	Virtual temperature	The virtual temperature profile obtained using a RASS is used to estimate the convective mixing height in the same manner that temperature data are used (limited to the range of the RASS ≈ 1 km..).

Wind turbulence parameters and/or acoustic backscatter profiles derived from sodar data can also be used to estimate mixing height. These data can be used for both daytime and nighttime conditions, but only when the top of the mixing height is within the range of the sodar.

The refractive index structure parameter (C_n^2) calculated from radar wind profiler reflectivity measurements can also be used to estimate mixing height **[71]**. During nighttime hours, however, the mixing height may be below the range of the radar wind profile.

The virtual temperature profile obtained using a RASS instrument can be used to estimate convective mixing height in the same manner that temperature data are used; this is possible only when the mixing height is within the range of the RASS.

Turbulence Some sodars report wind turbulence parameters. In using these parameters, one must remember that sodars measure the vector components of the wind. Furthermore, there may be significant differences in time and space between the sampling of the components so that any derived variables using more than one component may be affected by aliasing. Thus, the derived turbulence parameters from sodars are generally not the same parameters that models expect for input. Numerous studies have been performed comparing sodar-based turbulence statistics with tower-based turbulence statistics. Findings from these studies have generally shown that measurements of the standard deviation of the vertical component of the wind speed (σ_w) are in reasonable agreement , while the standard deviation calculations incorporating more than one component (e.g., σ_θ) are not **[72]**. It is therefore recommended that, unless models are designed to use sodar-type statistical parameters, the use of derived turbulence parameters be limited to single component calculations such as σ_w. Note however that the utility of σ_w will depend upon the resolution of the sodar system.

9.1.2 Radiosonde Sounding System

Radiosonde sounding systems use *in situ* sensors carried aloft by a small, balloon-borne instrument package (the radiosonde, or simply "sonde") to measure vertical profiles of atmospheric pressure, temperature, and moisture (relative humidity or wet bulb temperature) as the balloon ascends. In the United States, helium is typically used to inflate weather balloons. Hydrogen is also used. The altitude of the balloon is typically determined using thermodynamic variables or through the use of satellite-based Global Positioning Systems (GPS). Pressure is usually measured by a capacitance aneroid barometer or similar sensor. Temperature is typically measured by a small rod or bead thermistor. Most commercial radiosonde sounding systems use a carbon hygristor or a capacitance sensor to measure relative humidity directly, although a wet-bulb sensor is also used by some systems. With a wet bulb, relative humidity and dewpoint are calculated from psychrometric relationships. Ventilation of the sensors occurs as the balloon rises. The temperature sensor is usually coated to minimize radiational heating effects. The humidity sensor is usually shielded in a ventilated duct inside the sonde's enclosure to minimize exposure to solar radiation.

A radiosonde includes electronic subsystems that sample each sensor at regular intervals (e.g., every 2 to 5 seconds), and transmit the data to a ground-based receiver and data acquisition system. Power for the radiosonde is provided by small dry-cell or wet-cell batteries. Most commercial radiosonde systems operate at 404 MHZ or 1680 MHZ. Once the data are received at the ground station, they are converted to engineering units based on calibrations supplied by the manufacturer. The data acquisition system reduces the data in near-real time, calculates the altitude of the balloon, and computes wind speed and direction aloft based on information obtained by the data systems on the position of the balloon as it is borne along by the wind. Commercial systems available today are relatively compact and easy to operate. The radiosondes are typically smaller than a shoebox and weigh only a few hundred grams. Thus, the previous need to use a parachute to slow the radiosonde's descent after the balloon has burst has greatly diminished, although the manufacturer should still be consulted on this matter. The data systems are either personal computer (PC)-based, or self-contained with standard PC-type computer interfaces for data communications (e.g., RS-232). Data are stored on conventional PC-type hard disks and/or diskettes.

Upper-air winds (horizontal wind speed and direction) are determined during radiosonde ascents by measuring the position of the radiosonde relative to the earth's surface as the balloon ascends. By measuring the position of the balloon with respect to time and altitude, wind vectors can be computed that represent the layer-averaged horizontal wind speed and wind direction for successive layers. The position data have typically been obtained using radio direction finding techniques (RDF) or one of the radio navigation (NAVAID) networks. The use of satellite-based GPS is becoming more common.

RDF systems use a tracking device called a radio theodolite to measure the position of the balloon relative to the ground station. The radio theodolite, which resembles a small tracking radar system, measures the azimuth and elevation angles to the radiosonde relative to the ground station. The radio theodolite automatically follows the motion of the balloon by tracking the primary lobe of the radiosonde's transmitter, making adjustments to the tilt and pointing direction of the antenna as it follows the signal from the sonde. The azimuth, elevation, and altitude information is then used by the data system to compute the length and direction of a vector projected onto the earth's surface that represents the resultant motion of the balloon over some suitable averaging period, typically 30 to 120 seconds.

With NAVAID systems, the radiosonde's position is determined by triangulation relative to the locations of the fixed NAVAID transmitters. The radiosonde and ground station have electronic subsystems to measure the time delay in the transmissions from the NAVAID sites and to convert this information into the relative motion of the radiosonde, from which winds aloft are computed.

GPS is a satellite navigation system, which is funded and controlled by the U.S. Department of Defense. The system was designed for and is operated by the U.S. military. GPS provides specially coded satellite signals that can be processed in a GPS receiver, enabling the receiver to compute position, velocity and time. GPS wind-finding system sondes consist of a 10-channel GPS (Global Positioning System) receiver as well as a platform for temperature, RH and pressure sensors.

The basic steps in performing a sounding involve: preparing the radiosonde (deploying the sensors, connecting the batteries, etc.); activating the data acquisition system and manually or automatically entering the radiosonde calibration information; inflating the balloon and attaching the sonde; releasing the balloon and activating the tracking system; monitoring the data during the sounding; and performing post-sounding procedures as required (e.g., completing sounding documentation, preparing backups of the data, transferring the data to a central data processing facility, etc.). For air quality programs, the entire procedure requires approximately one hour, and one to two operators. Prior to the release of the radiosonde, an accurate measurement must be made of the surface pressure to provide a baseline value for computing altitude from the radiosonde data. This baseline value is used to compute any offsets that are needed for the sonde's pressure measurements. A good quality barometer that is regularly calibrated and audited should be used to make this measurement. Other baseline readings that should be taken include temperature and moisture (wet bulb or relative humidity), and surface winds, although these data are typically not used to offset the sonde measurements.

High quality tracking information is necessary for obtaining high quality wind data within the atmospheric boundary layer. For monitoring programs with a strong emphasis on characterizing low-level boundary layer winds, it is important that the radio theodolite operator get the theodolite to “lock on” to the radiosonde transmission right from the moment of launch. Otherwise, a few minutes of wind data may be lost while the system acquires the signal and begins tracking the radiosonde automatically. Due to this type of delay, for example, typical National Weather Service (NWS) data collection procedures result in a smoothing of the winds within approximately the lowest 300 m. With NAVAID systems, it is important to ensure that position information is being acquired prior to release of the balloon. At some sites, high terrain or other obstacles may block the NAVAID radio signals, so that the balloon must be airborne for a few minutes before accurate position information is available. This, too, can cause a few minutes of wind data to be lost at the beginning of a sounding. Normally autonomous (single receiver) GPS position data are only accurate to about 100 meters due to the use of selective availability by the military to introduce an "uncertainty" into the signal. To compensate for this error, the meteorological sounding systems use the base (receiving) station as a differential GPS location which can increase GPS accuracy to better than 1 meter. The horizontal drift of the radiosonde from the release location may also result in the incomplete characterization of the vertical structure of small (spatial and or temporal) scale features.

Generally speaking, radiosonde soundings made for boundary layer air quality studies do not need to achieve the kind of high altitude coverage required for soundings made by the NWS, where data to the tropopause and to stratospheric levels are needed for weather forecasting. For most air quality studies, the vertical range for radiosonde data will not need to exceed 10,000 m msl (approximately 300 mb), and data coverage to 5000 m msl (approximately 500 mb) will be sufficient. In this case, a smaller weather balloon than that used by the NWS, e.g., a 100-gram balloon as opposed to a 300- to 600-gram balloon, is adequate. Balloon size is stated as weight rather than diameter because the weight relates directly to the amount of free lift needed to achieve the desired ascent rate during a sounding, which in turn influences how much helium must be used and, therefore, the cost per sounding.

In a compromise between adequate ventilation of the temperature and moisture sensors on the sonde and good vertical resolution in the boundary layer, ascent rates used for soundings made during air quality studies (2 to 3 ms^{-1}) are also typically less than that used by the NWS (5 to 6 ms^{-1}). As noted earlier, these ascent rates are consistent with an elapsed time of approximately one hour. Thus, the vertical resolution of the thermodynamic data is usually 5 to 10 m, depending on the interval at which the data acquisition system samples the signals from the radiosonde and the time response of the sensor. The vertical resolution of the wind data ranges from approximately 45 to 200 m, depending on the type of sounding system used. The data averaging interval for radiosondes is 1 to 2 minutes in the lower part of a sounding (e.g., lowest 3000 m) and approximately 3 to 4 minutes in the upper part of a sounding.

9.1.3 Doppler Sodar

Commercial sodars operated for the purpose of collecting upper-air wind measurements consist of antennas that transmit and receive acoustic signals. A mono-static system uses the same antenna for transmitting and receiving, while a bi-static system uses separate antennas. The difference between the two antenna systems determines whether atmospheric scattering by temperature fluctuations (in mono-static systems), or by both temperature and wind velocity fluctuations (in bi-static systems) is the basis of the measurement. The vast majority of sodars in use are of the mono-static variety due to their more compact antenna size, simpler operation, and generally greater altitude coverage. Figure 9-2 shows the beam configurations of mono-static and bi-static systems.

Mono-static antenna systems can be divided into two categories: those using multiple axis, individual antennas and those using a single phased-array antenna. The multiple-axis systems generally use three individual antennas aimed in specific directions to steer the acoustic beam. One antenna is generally aimed vertically, and the other two are tilted slightly from the vertical at an orthogonal angle. Each of the individual antennas may use a single transducer focused into a parabolic dish, or an array of speaker drivers and horns (transducers) all transmitting in-phase to form a single beam. Both the tilt angle from the vertical and the azimuth angle of each antenna need to be measured when the system is set up. Phased-array antenna systems use a single array of speaker drivers and horns (transducers), and the beams are electronically steered by phasing the transducers appropriately. To set up a phased-array antenna, one needs to measure the pointing direction of the array and ensure that the antenna is either level or oriented as specified by the manufacturer.

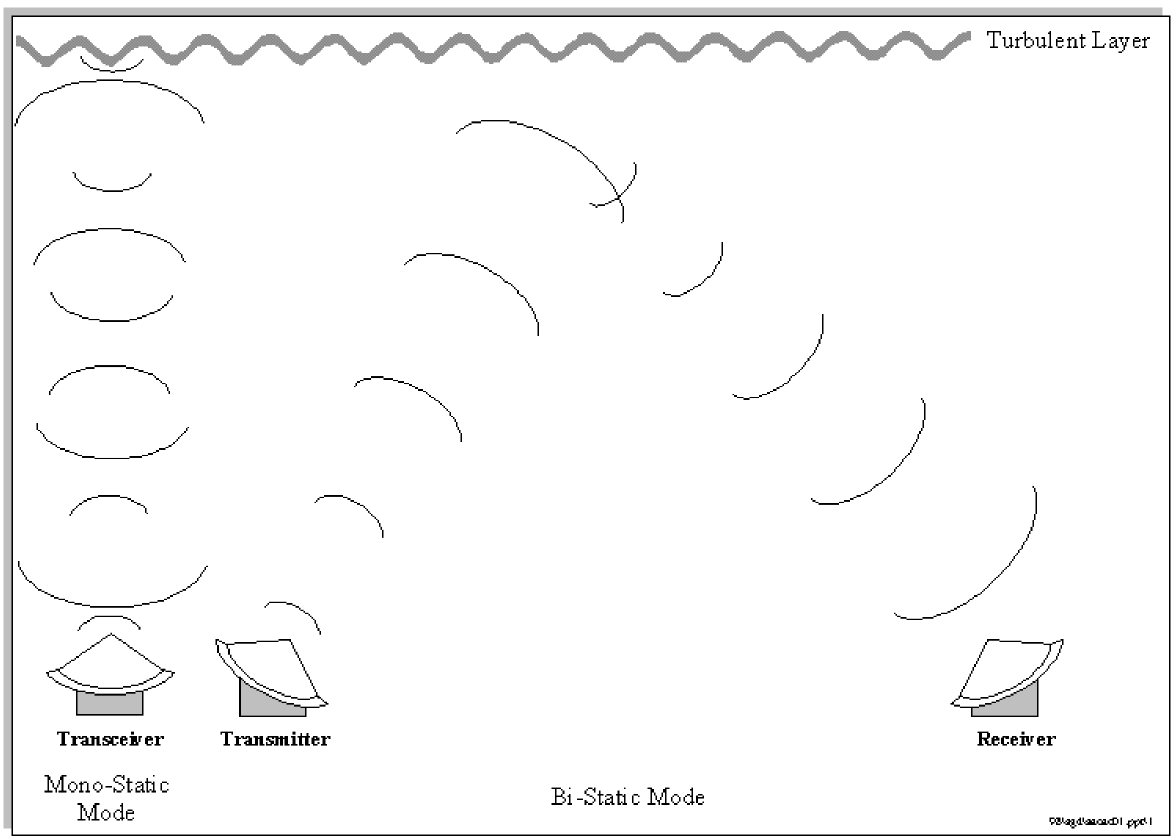

Figure 9-2 Simple depiction of a monostatic and bistatic sodar.

The horizontal components of the wind velocity are calculated from the radially measured Doppler shifts and the specified tilt angle from the vertical. The tilt angle, or zenith angle, is generally 15° to 30°, and the horizontal beams are typically oriented at right angles to one another. Since the Doppler shift of the radial components along the tilted beams includes the influence of both the horizontal and vertical components of the wind, a correction for the vertical velocity should be applied in systems with zenith angles less than 20°. In addition, if the system is located in a region where expected vertical velocities may be greater than about 0.2 ms^{-1}, corrections for the vertical velocity should be made regardless of the beam's zenith angle.

The vertical range of sodars is approximately 0.2 to 2 kilometers (km) and is a function of frequency, power output, atmospheric stability, turbulence, and, most importantly, the noise environment in which a sodar is operated. Operating frequencies range from less than 1000 Hz to over 4000 Hz, with power levels up to several hundred watts. Due to the attenuation characteristics of the atmosphere, high power, lower frequency sodars will generally produce greater height coverage. Some sodars can be operated in different modes to better match vertical resolution and range to the application. This is accomplished through a relaxation between pulse length and maximum altitude, as explained in Section 9.1.4 for radar wind profilers.

Sodar systems should include available options for maximizing the intended capabilities (e.g., altitude range, sampling resolution, averaging time) of the system and for processing and validating the data. The selection of installation site(s) should be made in consultation with the manufacturer and should consider issues associated with the operation of the sodar instrument. Training should be obtained from the manufacturer on the installation, operation, maintenance, and data validation. Additional information on these issues is provided in Section 9.5 of this document.

9.1.4 Radar Wind Profiler

Operating characteristics of three common types of radar wind profilers are given in Table 9-3. The categories included in the table are: 1) very high frequency (VHF) profilers that operate at frequencies near 50 MHZ; 2) ultra-high frequency (UHF) tropospheric profilers that operate at frequencies near 400 MHZ; and 3) UHF lower tropospheric profilers that operate at frequencies near 1000 MHZ. The guidance provided herein is intended for radar wind profilers that fall into the third category; i.e., UHF lower tropospheric profilers (also called boundary layer radar wind profilers).

Doppler radar wind profilers operate using principles similar to those used by Doppler sodars, except that electromagnetic (EM) signals are used rather than acoustic signals to remotely sense winds aloft. Figure 9-3 shows an example of the geometry of a UHF radar wind profiler equipped with a RASS unit (see Section 9.1.5). In this illustration, the radar can sample along each of five beams: one is aimed vertically to measure vertical velocity, and four are tilted off vertical and oriented orthogonal to one another to measure the horizontal components of the air's motion. A UHF profiler includes subsystems to control the radar's transmitter, receiver, signal processing, and RASS (if provided), as well as data telemetry and remote control.

Detailed information on profiler operation can be found in references **[73]** and **[74]**; a brief summary of the fundamentals is provided in the following. The radar transmits an electromagnetic pulse along each of the antenna's pointing directions. The duration of the transmission determines the length of the pulse emitted by the antenna, which in turn corresponds to the volume of air illuminated (in electrical terms) by the radar beam. Small amounts of the transmitted energy are scattered back (referred to as backscattering) toward and received by the radar. Delays of fixed intervals are built into the data processing system so that the radar receives scattered energy from discrete altitudes, referred to as range gates. The Doppler frequency shift of the backscattered energy is determined, and then used to calculate the velocity of the air toward or away from the radar along each beam as a function of altitude. The source of the backscattered energy (radar “targets”) is small-scale turbulent fluctuations that induce irregularities in the radio refractive index of the atmosphere. The radar is most sensitive to scattering by turbulent eddies whose spatial scale is ½ the wavelength of the radar, or approximately 16 centimeters (cm) for a UHF profiler.

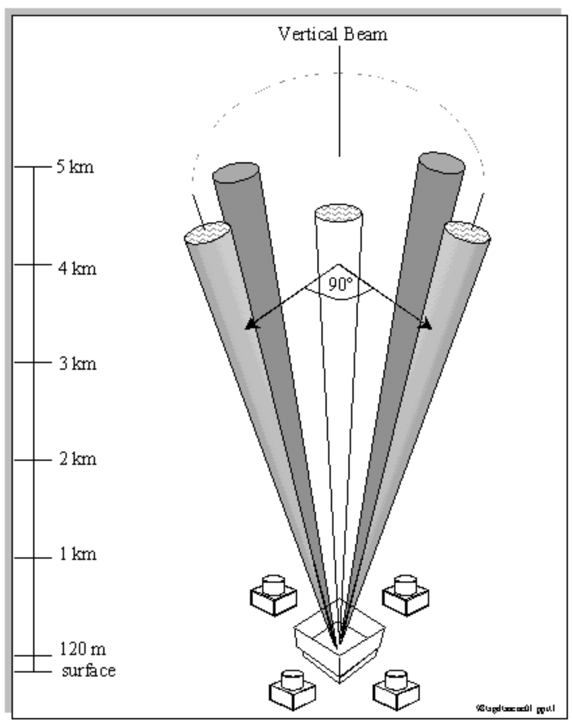

Figure 9-3 Schematic of sampling geometry for a radar wind profiler with RASS.

Table 9-3

Characteristics of radar wind profilers

Frequency Class	Antenna Size (m^2)	Peak Power (kw)	Range (km)	Resolution (m)	Alias and Prototypes
50 MHZ	10,000	250	2-20	150-1000	Alias: VHF radar wind profiler Prototype: 50 MHZ (600 cm) profiler used in the Colorado Wind Profiler Network in 1983.
400 MHZ	120	40	0.2-14	250	Alias: UHF (tropospheric) radar wind profiler Prototypes: 404 MHZ (74 cm) profiler developed for the Wind Profiler Demonstration Network (WPDN) in 1988. 449 MHZ (67 cm) profiler operates at the approved frequency for UHF profilers and will eventually replace the 404 MHZ units. 482 MHZ (62 cm) profiler used by the German Weather Service.
1000 MHZ	3-6	0.5	0.1-5	60-100	Alias: UHF lower-tropospheric radar wind profiler Boundary layer radar wind profiler Lower-atmospheric radar wind profiler Prototypes: 915 MHZ (33 cm) profiler used in the Colorado Wind Profiler Network in 1983. 1290 MHZ (23 cm) boundary layer profiler used by the German Weather Service.

A profiler's (and sodar's) ability to measure winds is based on the assumption that the turbulent eddies that induce scattering are carried along by the mean wind. The energy scattered by these eddies and received by the profiler is orders of magnitude smaller than the energy transmitted. However, if sufficient samples can be obtained, then the amplitude of the energy scattered by these eddies can be clearly identified above the background noise level, then the mean wind speed and direction within the volume being sampled can be determined.

The radial components measured by the tilted beams are the vector sum of the horizontal motion of the air toward or away from the radar and any vertical motion present in the beam. Using appropriate trigonometry, the three-dimensional meteorological velocity components (u,v,w) and wind speed and wind direction are calculated from the radial velocities with corrections for vertical motions. A boundary-layer radar wind profiler can be configured to compute averaged wind profiles for periods ranging from a few minutes to an hour.

Boundary-layer radar wind profilers are often configured to sample in more than one mode. For example, in a "low mode," the pulse of energy transmitted by the profiler may be 60 m in length. The pulse length determines the depth of the column of air being sampled and thus the vertical resolution of the data. In a "high mode," the pulse length is increased, usually to 100 m or greater. The longer pulse length means that more energy is being transmitted for each sample, which improves the signal-to-noise ratio (SNR) of the data. Using a longer pulse length increases the depth of the sample volume and thus decreases the vertical resolution in the data. The greater energy output of the high mode increases the maximum altitude to which the radar wind profiler can sample, but at the expense of coarser vertical resolution and an increase in the altitude at which the first winds are measured. When radar wind profilers are operated in multiple modes, the data are often combined into a single overlapping data set to simplify post-processing and data validation procedures.

9.1.5 RASS

The principle of operation behind RASS is as follows: Bragg scattering occurs when acoustic energy (i.e., sound) is transmitted into the vertical beam of a radar such that the wavelength of the acoustic signal matches the half-wavelength of the radar. As the frequency of the acoustic signal is varied, strongly enhanced scattering of the radar signal occurs when the Bragg match takes place. When this occurs, the Doppler shift of the radar signal produced by the Bragg scattering can be determined, as well as the atmospheric vertical velocity. Thus, the speed of sound as a function of altitude can be measured, from which virtual temperature (T_v) profiles can be calculated with appropriate corrections for vertical air motion. The virtual temperature of an air parcel is the temperature that dry air would have if its pressure and density were equal to those of a sample of moist air. As a rule of thumb, an atmospheric vertical velocity of 1 ms^{-1} can alter a T_v observation by 1.6°C.

RASS can be added to a radar wind profiler or to a sodar system. In the former case, the necessary acoustic subsystems must be added to the radar wind profiler to generate the sound signals and to perform signal processing. When RASS is added to a radar profiler, three or four vertically pointing acoustic sources (equivalent to high quality stereo loud speakers) are placed around the radar wind profiler's antenna, and electronic subsystems are added that include the acoustic power amplifier and the signal generating circuit boards. The acoustic sources are used only to transmit sound into the vertical beam of the radar, and are usually encased in noise suppression enclosures to minimize nuisance effects that may bother nearby neighbors or others in the vicinity of the instrument.

When RASS is added to a sodar, the necessary radar subsystems are added to transmit and receive the radar signals and to process the radar reflectivity information. Since the wind data are obtained by the sodar, the radar only needs to sample along the vertical axis. The sodar transducers are used to transmit the acoustic signals that produce the Bragg scattering of the radar signals, which allows the speed of sound to be measured by the radar.

The vertical resolution of RASS data is determined by the pulse length(s) used by the radar. RASS sampling is usually performed with a 60- to 100-m pulse length. Because of atmospheric attenuation of the acoustic signals at the RASS frequencies used by boundary layer radar wind profilers, the altitude range that can be sampled is usually 0.1 to 1.5 km, depending on atmospheric conditions (e.g., high wind velocities tend to limit RASS altitude coverage to a few hundred meters because the acoustic signals are blown out of the radar beam).

9.2 Performance Characteristics

The following references provide documentation of performance characteristics for the upper-air measurement platforms covered in this guidance (lidar is included for completeness):

- Rawinsonde **[9] [75] [76] [77] [78] [79] [80] [81]**
- Sodar **[82] [83] [84] [85] [86] [87] [88]**
- Radar wind profiler **[89] [90] [91] [92]**
- RASS **[93] [94] [95] [96]**
- Lidar **[83] [97] [98] [99]**

9.2.1 Definition of Performance Specifications

Accuracy is defined as the degree of agreement of a measurement with an accepted reference or true value **[2]**. Determining the absolute accuracy of an upper-air instrument through an inter-comparison study is difficult because there is no "reference" instrument that can provide a known or true value of the atmospheric conditions. This is due in part to system uncertainties and inherent uncertainties caused by meteorological variability, spatial and temporal separation of the measurements, external and internal interference, and random noise. The only absolute accuracy check that can be performed is on the system electronics, by processing a simulated signal. Similarly, a true precision, or the standard deviation of a series of measured values about a mean measured reference value, can only be calculated using the system responses to repeated inputs of the same simulated signal.

The performance specifications provided by manufacturers for accuracy, precision, and other data quality objectives are derived in a number of ways, and it is prudent to understand the basis behind the published specifications. Manufacturers' specifications may be derived from the results of inter-comparison studies, from what the instrument system can resolve through the system electronics and processing algorithms, or a combination of these methods. It may not be practical for a user to verify the exact specifications claimed by the manufacturers. What is needed, however, is a means of verifying that the data obtained from an upper-air system compare reasonably to observations obtained from another measurement system. Guidance for system acceptance testing, field testing, auditing, and data comparison is provided in Section 9.6.

To quantify the reasonableness of the data, one compares observations from the upper-air system being evaluated to data provided by another sensor that is known to be operating properly. In assessing how well the sensors compare, two measures are commonly used. The first involves calculating the "systematic difference" between the observed variables measured by the two methods. The second involves calculating a measure of the uncertainty between the measurements, which is referred to as the "operational comparability" (or simply "comparability"), as described in reference **[100]**. Comparability, for these purposes, is the root-mean-square (rms) of a series of differences between two instruments measuring nearly the same population. The comparability statistic provides a combined measure of both precision and bias, and will express how well the two systems agree.

Using the ASTM notation **[100]**, the systematic difference (or bias) is defined as:

$$d = \frac{1}{n}\sum (x_{a,i} - x_{b,i}) \qquad \textbf{(9-1)}$$

where

n	=	number of observations
$x_{a,i}$	=	ith observation of the sensor being evaluated
$x_{b,i}$	=	ith observation of the "reference" instrument

Operational comparability (or root-mean-square error) is defined as

$$c = \sqrt{\frac{1}{n}\sum (x_{a,i} - x_{b,i})^2} \qquad \textbf{(9-2)}$$

Many of the inter-comparison programs discussed in the next section have evaluated instrument performance using the systematic difference and comparability statistics described here. Other statistical measures that can be used include, for example, correlation coefficients and linear regression.

Another important performance specification for upper-air instrument systems is data recovery rate. Data recovery is usually calculated as the ratio of the number of observations actually reported at a sampling height to the total number of observations that could have been reported so long as the instrument was operating (i.e., downtime is usually not included in data recovery statistics but is treated separately). Data recovery is usually expressed as percent as a function of altitude. Altitude coverage for upper-air data is often characterized in terms of the height up to which data are reported 80 percent of the time, 50 percent of the time, etc.

9.2.2 Performance Characteristics of Radiosonde Sounding Systems

Radiosonde sounding systems are the most widely used upper-air instruments. The wind and thermodynamic data provided by these systems are critical to the numerical weather prediction (NWP) and forecasting programs conducted by all countries that provide such services. Thus, the performance characteristics of radiosondes and the relative accuracy of radiosonde winds have been the subject of a great deal of scrutiny over the last few decades. The World Meteorological Organization (WMO) and national weather agencies such as the U.S. NWS and British Meteorological Office have all sanctioned a number of inter-comparison studies to determine the performance characteristics of radiosonde systems (references **[9]**, **[75]**, and **[77]**). Inter-comparison and performance evaluation studies have also been conducted by independent researchers who have been interested in determining the accuracy of radiosonde wind and/or thermodynamic measurements for meeting specific research objectives (see reference**[81]** for a recent summary of some of these studies, especially those related to boundary-layer measurements). Some references are also provided in Table 9-4. Radiosonde systems will continue to be an important source of upper-air data for the foreseeable future, and efforts to characterize and improve radiosonde sounding system performance specifications continues **[79]**.

Performance tests of radiosonde systems have involved “flying” multiple radiosondes on the same balloon, and/or obtaining independent tracking information using high-precision tracking radars **[79]**. Such tests do not provide information on absolute accuracy of either the radiosondes or the tracking systems. Rather, they provide measures of the relative differences between comparable instrument systems, e.g., of temperature or relative humidity measured by different radiosondes flown at the same time and winds measured by radio theodolites or NAVAID systems. The NWS and WMO perform such tests to quantify the functional precision of the instruments, which is defined as the rms of the differences between the measurements, that is, if the differences have a Gaussian distribution then 67 percent of the differences would lie within the range specified by the functional precision. The functional precision is thus similar to the comparability statistic defined by Equation 9-2. Performance specifications for radiosonde systems are summarized in Table 9-1, the performance specifications are based on manufacturer's specifications and inter-comparison tests described in references **[77]** and **[79]**.

Errors and uncertainties encountered in radiosonde measurements, particularly errors in temperature and moisture, can occur at higher altitudes (e.g., beginning in the upper-troposphere), and are caused by factors such as exposure to solar radiation, sensor heating, and time lag. Data collected at lower altitudes (e.g., below about 10 km) do not tend to display such errors. Likewise, the relative accuracy of upper-air winds measured by radiosondes tends to decrease with increasing altitude. This is due in part to many weather services using radio theodolite sounding systems, where errors in tracking angles (especially elevation) become more troublesome as the balloon approaches the horizon and the antenna reaches its tracking limit.

At altitudes below about 10 km, radiosonde winds tend to show good agreement with other independent upper-air measurements **[79]**. As noted earlier in this document, there are circumstances under which data resolution within the lowest few hundred meters can be compromised.

9.2.3 Performance Characteristics of Remote Sensing Systems

Many of the studies that have been performed to estimate the accuracy and precision of remote sensors were based on inter-comparisons to tower-based measurements. These comparisons have generally assumed that the tower measurements provide the known standard and are representative of the same environment measured by the remote sensors. However, differences between point measurements from *in situ* sensors located on the tower and volume-averaged measurements from the remote sensors located near the tower are expected to lead to differences in the results, even though conditions for these inter-comparisons are likely as close to "ideal" as one could expect. The performance of remote profiling instrumentation is greatly influenced by individual site characteristics, instrument condition, and operating parameters established for the equipment.

Table 9-1 includes estimates of expected performance characteristics for remote sensing systems that are installed and working properly. These results should be used for establishing data quality objectives for upper-air programs and as a basis for interpreting results from inter-comparison programs or performance audits of upper-air equipment (see Section 9.6). To avoid ambiguities in wind direction associated with light and variable winds, it is recommended that the wind direction comparability calculations be made only when actual wind speeds are greater than approximately 2 ms^{-1}.

9.3 Monitoring Objectives and Goals

When the primary use of upper-air data is for the analysis and modeling of meteorological and air quality conditions in the boundary layer and lower troposphere, the focus of the upper air program should be to maximize the temporal and spatial resolution of the data collected in this portion of the atmosphere, i.e. the first one to three km. Each modeling and analysis application will have its own unique objectives and scales of interest. However there are certain characteristics that have a large bearing on the type of upper-air measurement system chosen, the manner in which it is operated, and data processing and archival procedures. These characteristics include the duration of the measurement program, that is whether the measurements are part of a long-term monitoring program of seasonal to yearly extent, or a shorter-term intensive field campaign characterized by a greater number of measurements. The types of measured and derived meteorological variables required for the modeling/analysis, including the required spatial and temporal resolution, will also affect the choice of measurement system, as will the need, in many cases, to make comparable measurements with surface-based meteorological systems.

The choice of upper-air measurement technologies is considerably greater now than at any time in the last two decades. With that choice comes the need to carefully consider the requirements of the application and to choose and configure the appropriate systems. Considerable field experience has been gained in the use of the various measurement technologies, especially since 1990. The following discussion for each class of upper-air measurement system is meant to stimulate thinking regarding the best match of the system to the specific application.

9.3.1 Data Quality Objectives

Inherent in any measurement program is the need to establish data quality objectives. These relate the quality of measurements obtained to the level of uncertainty that decision makers are willing to accept in the data and results derived from the data **[65]**. Data quality objectives state how "good" the data need to be to satisfy the program objectives. The stated objectives generally include completeness, systematic difference, and comparability. Operators of the instruments should let the data quality objectives be determined based on instrument performance specifications and modeling and analysis needs. Data quality objectives should be specified for all of the primary variables measured by the instrument.

To check whether or not the data meet the data quality objectives from an instrument performance perspective, a comparison to another sensor that is known to be operating properly is recommended (see Section 9.5). In assessing how well the sensors compare, the systematic difference and the operational comparability can be computed and compared to the data quality objectives that are presented in Table 9-4.

In evaluating the sodar and radar wind profiler data, the primary criteria for comparison are the component data; the vector wind speed and wind direction are secondary. The indicated values for u and v for the sodar and radar wind profiler in Table 9-4 refer to the components along the antenna axes, and for these instruments, the component comparisons should be performed using calculated values along the antenna axes. Values along the meteorological axes (north/south and east/west) should only be used if evaluating a radiosonde. For the sodar and radar wind profiler, the data quality objective for the vector wind speed and wind direction comparisons should be applied when winds are greater than 2 to 3 ms^{-1}. Note that the values presented in Table 9-5 are based on a number of studies and were reviewed by several measurement experts participating in an EPA-sponsored workshop on upper-air measurement systems.

Table 9-4.

Suggested data quality objectives for upper-air measurement systems.

Measurement Method	Systematic Difference	Comparability
Radiosonde	p:± 0.5 mb T: ± 0.2°C RH: ± 10% u,v: ± 0.5 to 1 ms^{-1}	P (as height):± 24 m T: ± 0.6°C T_d: ± 3.3°C WS: ± 3.1 ms^{-1} WD: ± 18° to ± 5°[a]
Sodar[b]	u,v: ± 1 ms^{-1} WS: ± 1 ms^{-1} WD: ± 10°	u,v: ± 2 ms^{-1} WS: ± 2 ms^{-1} WD: ± 30°
Radar wind profiler[b]	u,v: ± 1 ms^{-1} WS: ± 1 ms^{-1} WD: ± 10°	u,v: ± 2 ms^{-1} WS: ± 2 ms^{-1} WD: ± 30°
RASS	±1°C	±1.5°C

[a] Over a WS range from 3 to 21 ms^{-1}.

[b] For wind speeds greater than approximately 2 ms^{-1}.

Comparison results in excess of the data quality objectives do not necessarily mean that the data are invalid. In making this assessment, it is important to understand the reasons for the differences. Reasons may include unusual meteorological conditions, differences due to problems in one or both instruments, or differences due to sampling techniques and data reduction protocols. Both the reasons for and the magnitude of the differences, as well as the anticipated uses of the data, should be considered in determining whether the data quality objectives are met. This assessment should be part of the QA protocol.

Data completeness for radiosonde sounding systems is usually not significantly affected by outside environmental conditions such as high winds, precipitation, or atmospheric stability. However, environmental factors can have a significant effect on the rate of data capture for remote sensing systems.

9.4 Siting and Exposure

Siting and exposure issues related to radiosonde sounding systems, sodar, radar wind profiler, and RASS meteorological measurement systems are addressed in this section.

Careful planning should accompany the siting of upper-air measurement systems, since siting and exposure directly affect the quality of the data. The complexities of ground based remote sensing devices provide a challenge for the user to balance the conditions favorable for the technology with the availability of sites and the overall data collection goals of the program. Site selection may benefit from the experience of vendors or users of the type of instrument to be installed. Additional information on siting can be found in reference **[2]**. Listed below are some key issues to consider in siting upper-air systems.

- **Representative location.** Sites should be located where upper-air data are needed to characterize the meteorological features important to meeting the program objectives. Panoramic photographs should be taken of the site to aid in the evaluation of the data and preparation of the monitoring plan. Data collected at sites in regions with local geographic features such as canyons, deep valleys, etc., may be unrepresentative of the surrounding area and should be avoided, unless such data are needed to resolve the local meteorological conditions. Measurements made in complex terrain may be representative of a much smaller geographical area than those made in simple homogeneous terrain. See reference **[101]** for a discussion of the influence of terrain on siting and exposure of meteorological instrumentation.

- **Site logistics.**
  - Adequate power should be available for the instrument system as well as an environmentally controlled shelter that houses system electronics, and data storage and communication devices.
  - The site should be in a safe, well lit, secure area with level terrain, sufficient drainage, and clear of obstacles. The site should allow adequate room for additional equipment that may be required for calibrations, audits, or supplementary measurements.
  - A fence should be installed around the equipment and shelter to provide security, and appropriate warning signs should be posted as needed to alert people to the presence of the equipment.
  - A remote data communications link (e.g., dedicated leased line, standard dial-up modem line, or a cellular telephone link) should be installed at the monitoring site. It is recommended that a 9600 baud or higher line be established to facilitate rapid data transfer and uploading and downloading of information. A site in a remote location with no communication capabilities may collect valid data, but if the system goes down it may not be discovered until the next time the site is visited.

- **Collocation with surface meteorological measurements.** Several advantages can be gained by locating an upper-air site with or near an existing meteorological monitoring station. For instance, collocated data can be used for data validation purposes and for performing reasonableness checks (e.g., do surface winds roughly agree with near-surface upper-air winds, surface temperatures with near-surface RASS measurements). Existing shelter, power, and personnel could also be used for operating the upper-air instrument. Additional surface meteorological measurements of wind speed, wind direction, temperature and humidity are recommended. The height of the wind sensors will depend on the terrain. In homogeneous terrain, wind data collected at a height of 10 m may be sufficient.

- **Instrument noise.** Sodar and RASS generate noise that can disturb nearby neighbors. Depending on the type of sodar or RASS instrument, power level, frequency, acoustic shielding around the system, and atmospheric conditions, the transmitted pulse can be heard from tens of meters up to a kilometer away. An optimum site is one that is isolated from acoustically sensitive receptors **[102]**.

- **Passive interference/noise sources**. Objects such as stands of trees, buildings or tall stacks, power lines, towers, guy wires, vehicles, birds, or aircraft can reflect sodar or radar transmit pulses and contaminate the data. Not all sites can be free of such objects, but an optimum site should be selected to minimize the effects of such obstacles. If potential reflective “targets” are present at an otherwise acceptable site, the beams of the instrument should be aimed away from the reflective objects. In the case of sodars, locating the antennas so that there are no direct reflections from objects will help minimize potential contamination. In the case of the radar profiler, it is best to aim the antennas away from the object and orient a phased array antenna's corners so they are pointing toward the objects. As a rule of thumb, sites with numerous objects taller than about 15° above the horizon should be avoided. The manufacturers of the remote sensing equipment should be contacted regarding software that may be available to identify and minimize the effects of these passive noise sources.

- **Active interference/noise sources.** For sodars, noise sources such as air conditioners, roadways, industrial facilities, animals, and insects will degrade the performance of sodar systems **[102]**. If proximity to such sources cannot be avoided, then additional acoustic shielding may help minimize the potentially adverse effects on the data. In general, noise levels below 50 decibels (dBA) are considered to be representative of a quiet site, while levels above 60 dBA are characteristic of a noisy site. For radar wind profilers and RASS, radio frequency (RF) sources such as radio communications equipment and cellular telephones may have an adverse effect on performance.

- **Licenses and Ordinances**. Before operating a remote sensor it is recommended that all applicable requirements for operation of equipment be addressed. For example, to operate a radar wind profiler or a RASS, a Federal Communications Commission (FCC) license is required. For radiosonde sounding systems (or other balloon-borne systems), a Federal Aviation Administration (FAA) waiver may be required. Local noise ordinances may limit the operation of sodar or RASS instruments. Some of these requirements may take several months to address and complete.

- **Surveying Candidate Locations.** Prior to final site selection, a survey is recommended to identify audio sources **[103]** and RF sources that may degrade system performance. Additionally, panoramic photographs should be taken to aid in the evaluation of the candidate site and for the preparation of the monitoring plan. As part of the survey, appropriate topographic and other maps should be used to identify other potential sources of interference, such as roadways and airports.

9.5 Installation and Acceptance Testing

This section provides guidance for the installation and acceptance testing of upper-air monitoring systems; similar guidance for in situ sensors is provided in Section 8.2.

The installation period is the optimal time to receive appropriate training in instrument principles, operations, maintenance, and troubleshooting, as well as data interpretation and validation. Meteorological consultants as well as some manufacturers and vendors of meteorological instruments provide these services.

Installation procedures specific to upper-air monitoring systems include the following:

- The latitude, longitude, and elevation of the site should be determined using U.S. Geological Survey (USGS) topographical maps, other detailed maps, or a GPS instrument.
- The orientation of antennas of the sodar, radar profiler, or radio theodolite systems should be defined with respect to true north. One recommended method is to use the solar siting technique **[2]** . This technique enables determination of true north at any location using a compass (or other pointing device suitable for measuring the azimuth angle to the sun), a computer program, the site latitude and longitude, and accurate local time.
- The site should be documented as follows:
    - Photographs in sufficient increments to create a documented 360° panorama around the antennas should be taken. Additionally, pictures of the antenna installation, shelter and any obstacles that could influence the data should be obtained.
    - Photographs of the instrument, site, shelter, and equipment and computers inside the shelter should be obtained.
    - A detailed site layout diagram that identifies true north and includes the locations of the instrument, shelter, other equipment, etc. should be prepared. An example of such a diagram is shown in Figure 9-4. Additionally, it is recommended that the site layout diagram include the electrical and signal cable layout, and the beam directions of any remote sensor.
    - A vista table that documents the surroundings of the site in 30° increments should be prepared. Vistas for the beam directions, if they are not represented by the 30° views (±5°), should be included. The table should identify any potential passive and active noise sources in each direction, and the approximate distance and elevation angle above the horizon to the objects. An example is shown in Table 9-5.

An acceptance test is used to determine if an instrument performs according to the manufacturer's specifications **[2]**. Manufacturer's procedures for unpacking, inspection, installation, and system diagnostics should be followed to assure that all components are functioning appropriately. All acceptance-testing activities should be documented in the station log.

Once the system is installed, a final field check is needed to assure that the data are reasonable. This is best performed using collocated meteorological information from towers or other upper-air sensors. In the absence of these data sources, nearby upper-air data from the NWS radiosonde network, the NOAA profiler network, aircraft reports, National Center for Environmental Prediction (NCEP) high resolution mesoscale analyses, or other upper-air data can be used. It is important to have an individual trained in the interpretation of the data perform a thorough review of at least several days of data. This check is not meant to evaluate whether or not the data meet the manufacturer's data specifications, but is intended to identify problems such as:

- Component failures
- Incorrect or improper operating/sampling parameters
- Antenna azimuth angles specified improperly or incorrectly measured
- Siting problems (active and passive interfering noise sources)

Shortly after the installation and startup of an instrument, a system and performance audit should be performed. These audits will provide information for the qualitative and quantitative assessment of the performance of the system, as well as the adequacy of the standard operating procedures used for collection, processing, and validation of the data. To best assure that the data collected is of known quality, and that potential problems are identified early, it is recommended the initial audit be performed within 30 days of the start-up date.

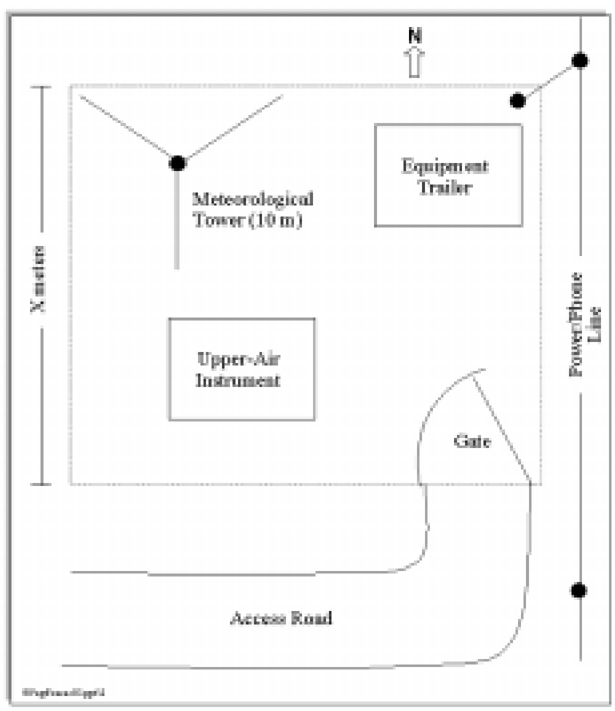

Figure 9-4 Example site layout diagram.

9.6 Quality Assurance and Quality Control

This section provides information on QAQC procedures unique to upper-air measurement systems. Generic material on QAQC procedures for meteorological systems and definitions of terms used in QAQC is presented in Section 8.

With some exceptions (e.g., rawinsonde measurements of pressure, temperature, and humidity) upper-air monitoring systems provide indirect measurements of the meteorological variables used in dispersion modeling. This presents a unique challenge to the quality assurance and quality control (QAQC) of these systems; for example, there is no upper-air counterpart to the bench top calibration of a wind vane. The alternative to the bench-top calibration is a calibration using a collocated transfer standard; this involves locating an identical instrument as close as practical to the instrument being calibrated (see Section 8.3) - again, as with the bench-top procedure, there is no upper-air counterpart to the collocated transfer standard for a wind vane. Similarly, there is no upper-air counter part to the performance audit of a wind vane (as explained in Section 8, calibrations and audits are one and the same as far as "what" takes place; the difference has to do with the independence of the person conducting the audit). Given the inability to conduct a true performance audit, the onus for claims of data validity for most upper-air measurements falls on the systems audit - this, as explained in Section 8.4, is essentially a challenge to the QAPP and provides an overall assessment of the commitment to data validity.

Alternative procedures for calibrations and performance audits of upper-air measurement systems are based on inter-comparisons with other measurement systems - these alternatives are discussed in Sections 9.6.1 (Calibration Methods) and 9.6.2 (Systems and Performance Audits).

Before discussing quality assurance programs, it is useful to explain the difference between quality control (QC) and quality assurance (QA). For the purposes of this document, QC refers to the operational procedures used to ensure that a measurement process is working properly. QC procedures include periodic instrument calibrations, site checks, data examination for reasonableness, and data validation. QC procedures produce quantitative documentation upon which claims of accuracy can be based. QA refers to all the planned or systematic actions necessary to provide adequate confidence that the entire measurement process is producing data that meets the data quality objectives established for a monitoring program. These actions include routine evaluation of how the QC procedures are implemented (system audits) and assessments of instrument performance (performance audits). Summarized below are details on the preparation of a Quality Assurance Project Plan (QAPP) and key elements that are unique to upper-air measurement methods.

Table 9-5

Example site vista table

VISTA, ORIENTATION, AND LEVEL AUDIT RECORD			
Date:	January 3, 1996	Site Name:	Site 5
Key Person:	John Sitetech	Project:	ABC
Instrument:	Radar Wind Profiler	Latitude:	31°10'25"
Model Number:	GEN-1500	Longitude:	91°15'33"
Serial Number:	1234	Elevation:	172 m
Software version:	3.95		
Rotation angle		Direction	
System:	147°true	Beam 1:	146°
Measured:	146°true	Beam 2:	236°
Difference:	1°		
		Firing order:	W, beam 1, beam 2
Array Level:	< 0.5°	Declination:	11° east (solar verification)
Azimuth Angle (deg.)			
Magnetic	True	Terrain Elevation Angle (deg.)	Features/Distance
--	0	12	Buildings and power lines at ~ 300 m.
--	30	19	Stack at 150-200 m.
--	60	22	Power pole at 10 m, < 5° beyond.
--	90	4	Low trees and bushes at 10 m.
--	120	15	Power lines at 200-300 m
--	150	4	Trees at 30-40 m.
----	180	0	Looking out over the lake.
--	240	< 2	Looking out over the lake, can see land.
--	270	< 2	Looking out over the lake, can see land.
--	300	3	Trees and telephone pole at 100 m.
--	330	14	Light pole at 25 m. Buildings at ~250 m.

9.6.1 Calibration Methods

A calibration involves measuring the conformance to or discrepancy from a specification for an instrument and an adjustment of the instrument to conform to the specification. In this sense, other than directional alignment checks, a true calibration of the upper-air instruments described in this document is difficult. Due to differences in measurement techniques and sources of meteorological variability, direct comparison with data from other measurement platforms is not adequate for a calibration. Instead, a calibration of these sensors consists of test signals and diagnostic checks that are used to verify that the electronics and individual components of a system are working properly. Results from these calibrations should not be used to adjust any data. All calibrations should be documented in the station log.

System calibration and diagnostic checks be performed at six month intervals, or in accordance with the manufacturer's recommendations, whichever is more frequent. The alignment of remote sensing antennas, referenced to true north, should be verified at six month intervals. Generic guidance and definitions of terms related to calibrations is provided in Section 8.3.

<u>Radiosonde Sounding Systems</u> For radiosonde sounding systems, the primary calibration that is required is to obtain an accurate surface pressure reading using a barometer that is regularly calibrated and periodically audited. This pressure reading is used to determine if an offset needs to be applied to the radiosonde pressure data. If an offset is needed, the data systems of the commercially available instruments will make the adjustment automatically. It is also useful to obtain surface readings of temperature and atmospheric moisture using a psychrometer or similar instrument. These data can be used to provide a reality check on the radiosonde measurements. This check can be performed using data from a nearby tower. A more robust check can be made by placing the sonde in a ventilated chamber and taking readings that are then compared to temperature and moisture measurements made in the chamber using independent sensors. The alignment of the theodolite should be validated against the reference marker that was installed at the time of system setup.

<u>Sodar</u> Recent advances in instrumentation for auditing of sodar instruments **[104]** have led to the development of a transponder that can simulate a variety of acoustic Doppler shifted signals on certain sodars. This instrument can be used to verify the calibration of the sodar's total system electronics and, in turn, validate the overall system operation in terms of wind speed and altitude calculations. However, such a check should not be considered a “true” calibration of the system since it does not consider other factors that can affect data recovery. These factors include the system signal-to-noise ratio, receiver amplification levels, antenna speaker element performance, beam steering and beam forming for phased-array systems, and overall system electronic noise.

<u>Radar Wind Profilers and RASS</u> A transponding system for radar does not yet exist, but the feasibility of such a system is being explored. Therefore, there is no simple means at present of verifying the accuracy of the Doppler shifted signals in the field other than to perform a comparison with some other measurement system, as described later in this section. Instead, calibrations of radar wind profiler and RASS systems are performed and checked at the system component level. These checks should be performed in accordance with the manufacturer's

recommendations. Like some sodar systems, the radar systems use both software and hardware diagnostics to check the system components.

9.6.2 System and Performance Audits

Audits of upper-air instrumentation to verify their proper operation pose some interesting challenges. While system audits can be performed using traditional system checks and alignment and orientation techniques, performance audits of some instruments require unique, and sometimes expensive procedures. In particular, unlike surface meteorological instrumentation, the upper-air systems cannot be challenged using known inputs such as rates of rotation, orientation directions, or temperature baths. Recommended techniques for both system and performance audits of the upper-air instruments are described below. These techniques have been categorized into system audit checks and performance audit procedures for radiosonde sounding systems, radar wind profilers, sodars, and RASS.

9.6.2.1 Systems Audit

System audits of an upper-air station should include a complete review of the QAPP, any monitoring plan for the station, and the station's standard operating procedures. The system audit will determine if the procedures identified in these plans are followed during station operation. Deviations from the plans should be noted and an assessment made as to what effect the deviation may have on data quality. To ensure consistency in the system audits, a checklist should be used. System audits should be conducted at the beginning of the monitoring program and annually thereafter.

Radiosonde Sounding Systems For radiosonde sounding systems, an entire launch cycle should be observed to ensure that the site technician is following the appropriate procedures. The cycle begins with the arrival of the operator at the site and ends with completion of the sounding and securing of the station. The following items should be checked:

- Ground station initialization procedures should be reviewed to ensure proper setup.
- Sonde initialization procedures should be reviewed to verify that the sonde has been properly calibrated.
- Balloon inflation should be checked to ensure an appropriate ascent rate.
- Proper and secure attachment of sonde to balloon should be verified.
- Orientation of the radio theodolite antenna should be checked, using solar sitings when possible. The antenna alignment should be maintained within ±2°.
- The vertical angle of the radio theodolite antenna should be checked and should be within ±0.5°.
- Data acquisition procedures should be reviewed and a sample of the acquired data should be inspected.
- Data archiving and backup procedures should be reviewed.

- Flight termination and system shutdown procedures should be reviewed.
- Preventive maintenance procedures should be reviewed and their implementation should be checked.
- Data processing and validation procedures should be reviewed to ensure that questionable data are appropriately flagged and that processing algorithms do not excessively smooth the data.
- Data from several representative launches should be reviewed for reasonableness and consistency.
- Station logbooks, checklists, and calibration forms should be reviewed for completeness and content to assure that the entries are commensurate with the expectations in the procedures for the site.

Remote Sensing Instrumentation

A routine check of the monitoring station should be performed to ensure that the local technician is following all standard operating procedures (SOPs). In addition, the following items should be checked:

- The antenna and controller interface cables should be inspected for proper connection. If multi-axis antennas are used, this includes checking for the proper connection between the controller and individual antennas.
- Orientation checks should be performed on the individual antennas, or phased-array antenna. The checks should be verified using solar sitings when possible. The measured orientation of the antennas should be compared with the system software settings. The antenna alignment should be maintained within $\pm 2°$.
- For multi-axis antennas, the inclination angle, or zenith angle from the vertical, should be verified against the software settings and the manufacturer's recommendations. The measured zenith angle should be within $\pm 0.5°$ of the software setting in the data system.
- For phased-array antennas, the array should be level within $\pm 0.5°$ of the horizontal.
- For multi-axis sodar systems, a separate distinct pulse, or pulse train in the case of frequency-coded pulse systems, should be heard from each of the antennas. In a frequency-coded pulse system there may be a sound pattern that can be verified. The instrument manual should be referenced to determined whether there is such a pattern.
- For sodar systems, general noise levels should be measured, in dBA, to assess the ambient conditions and their potential influence on the performance of the sodar.
- The vista table for the site (see Section 9.5) should be reviewed. If a table is not available then one should be prepared.
- The electronic systems and data acquisition software should be checked to ensure that the instruments are operating in the proper mode and that the data being collected are those specified by the SOPs.

- Station logbooks, checklists, and calibration forms should be reviewed for completeness and content to assure that the entries are commensurate with the expectations in the procedures for the site.
- The site operator should be interviewed to determine his/her knowledge of system operation, maintenance, and proficiency in the performance of quality control checks.
- The antenna enclosures should be inspected for structural integrity that may cause failures as well as for any signs of debris that may cause drainage problems in the event of rain or snow.
- Preventive maintenance procedures should be reviewed for adequacy and implementation.
- The time clocks on the data acquisition systems should be checked and compared to a standard of ±2 minutes.
- The data processing procedures and the methods for processing the data from sub-hourly to hourly intervals should be reviewed for appropriateness.
- Data collected over a multi-day period (e.g., 2-3 days) should be reviewed for reasonableness and consistency. The review should include vertical consistency within given profiles and temporal consistency from period to period. For radar wind profilers and sodar, special attention should be given to the possibility of contamination of the data by passive or active noise sources.

9.6.2.2 Performance Audit and Comparison Procedures

Performance audits should be conducted at the beginning of the monitoring program and annually thereafter. A final audit should be conducted at the conclusion of the monitoring program. An overview of the recommended procedures for performance auditing is provided below.

Radiosondes Performance auditing of radiosonde sounding systems presents a unique challenge in that the instrument is used only once and is rarely recovered. Therefore, a performance audit of a single sonde provides little value in assessing overall system performance. The recommended approach is to audit only the instruments that are used to provide ground truth data for the radiosondes prior to launch (thermometer, relative humidity sensor, psychrometer, barometer, etc.). The reference instruments used to audit the site instruments should be traceable to a known standard. Details on these audit methods can be found in reference **[2]**.

In addition, a qualitative assessment of the direction and speed of balloon travel should be made during an observed launch for comparison with the computed wind measurements. An alternative approach is to attach a second sonde package to the balloon, track it from an independent ground station, and compare the results of the two systems. An optical tracking system is adequate for this type of comparison.

Remote Sensing Instrumentation Methods for performance audits and data comparisons of remote sensing instrumentation have been under development for a number of years. Only recently has interim guidance reference **[2]** been released to help standardize performance audit methods. Even with the release of that guidance, there are still a number of areas undergoing development. Recommended procedures for performance audits and data comparisons of remote sensors which are presented below typically incorporate inter-comparison checks. If inter-comparison checks are used, a quick review of the datasets should be performed before dismantling the comparison system.

Sodar. The performance audit is used to establish confidence in the ability of the sodar to accurately measure winds. A performance audit of a system typically introduces a known value into the sensor and evaluates the sensor response. It may not be possible to perform this type of audit for all types of sodar instruments. In this case, a comparison between the sodar and another measurement system of known accuracy should be performed to establish the reasonableness of the sodar data. With any of the audit or comparison methods, the evaluation of the data should be performed on a component specific basis that corresponds to the sodar beam directions. Any of the following approaches may be considered in the sodar performance evaluation.

- Comparison with data from an adjacent tall tower. Using this approach, conventional surface meteorological measurements from sensors mounted on tall towers (at elevations within the operating range of the sodar) are compared with the sodar data. This method should only be used if the tall tower is an existing part of a monitoring program and its measurements are valid and representative of the sodar location. At least 24 hours of data should be compared. The tower data should be time averaged to correspond to the sodar averaging interval and the comparisons should be made on a component basis. This comparison will provide an overall evaluation of the sodar performance as well as a means for detecting potential active and passive noise sources.
- Comparison with data from another sodar. This comparison uses two sodars operating on different frequencies. The comparison sodar should be located in an area that will allow it to collect data that is representative of the site sodar measurements. At least 24 hours of data should be collected for the comparison. If the measurement levels of the two sodars differ, the comparison sodar data should be volume averaged to correspond with the site sodar. Additionally, the comparison sodar time averaging should correspond to the site sodar. As with the adjacent tall tower, the comparison should be performed on a component basis. This comparison will provide an overall evaluation of the sodar performance as well as a means for detecting potential active and passive noise sources.
- Comparison with radiosonde data. This comparison uses data obtained from a radiosonde carried aloft by a free-flight, slow-rise balloon. The balloon should be inflated so the ascent rate is about 2 ms^{-1}. This will provide the appropriate resolution for the comparison data, within the boundary layer. The wind data should be volume averaged to correspond with the sodar data and the comparisons should be made on a component as well as a total vector basis. The launch times should be selected to avoid periods of changing meteorological conditions. For example, evaluation of the comparison data should recognize the potential differences due to differences in both the spatial and temporal resolution of the measurements (i.e., the instantaneous data collected by the radiosonde as compared with the time averaged data collected by the sodar). This comparison will provide an overall evaluation of the sodar performance as well as a means for detecting potential active and passive noise sources.
- Comparison with tethersonde data. The tethersonde comparison is performed using single or multi-sonde systems. Using this approach, a tethered balloon is used to lift the

sonde(s) to altitude(s) corresponding with the sodar measurement levels. This method should collect data at one or more layers appropriate to the program objectives. At a minimum, data corresponding to the equivalent of five sodar averaging periods should be collected at each altitude. Multiple altitudes can be collected simultaneously using a multi-sonde system with two or more sondes. The individual sonde readings should be processed into components that correspond to the sodar beam directions and then time averaged to correspond to the sodar averaging period. This comparison will provide an overall evaluation of the sodar performance as well as a means for detecting potential active and passive noise sources.

- Comparison with data from an anemometer kite. This measurement system is suitable in relatively high wind speed conditions that would preclude the use of a tethersonde. The kite anemometer consists of a small sled type kite attached to a calibrated spring gauge. Horizontal wind speeds are determined from the pull of the kite on the spring gauge. The altitude of the kite (i.e. the height of the measured wind) is determined from the elevation angle and the distance to the kite. The wind direction is determined by measuring the azimuth angle to the kite. At a minimum, data corresponding to the equivalent of five sodar averaging periods should be collected at a level appropriate to the monitoring program objectives. The wind speed and kite azimuth and elevation readings should be taken every minute. The individual readings should be processed into components that correspond to the sodar beam directions and then time averaged to correspond to the sodar averaging period. This comparison will provide an overall evaluation of the sodar performance as well as a means for detecting potential active and passive noise sources.

- Use of a pulse transponding system. A pulse transponding system provides a means of testing the sodar system processing electronics for accuracy through the interpretation of simulated Doppler shifted signals at known time intervals **[104]**. This method can be considered an audit rather than a comparison because it provides a signal input equivalent to a known wind speed, wind direction and altitude to test the response of a sodar system. At least three averaging periods of transponder data should be collected with the sodar in its normal operating mode. Depending on the sodar configuration, this method along with an evaluation of the internal consistency of the sodar data to identify potential passive and active noise sources, may serve as the performance audit without the need of further comparisons. In the case of phased array sodars, an additional comparison is needed to verify proper beam steering. This comparison may be performed using any of the methods above. For this check, three sodar averaging periods at a single level are sufficient. It should be noted that current transponder technology is limited to sodars with three beams.

<u>Radar Wind Profilers</u>. At present, the performance of radar wind profilers can only be evaluated by comparison to collocated or nearby upper-air measurements. Various types of comparison instruments can be used including tall towers, sodar, radiosonde sounding systems, and tethersondes. A tethersonde may be used, but care should be taken to ensure that it does not interfere with the radar operation. Since it is important to have confidence in the reference instrument, an independent verification of operation of the reference instrument should also be obtained. If using a sodar or a radiosonde sounding system, the procedures outlined above should be followed to ensure acceptable operation of the system. If data from an adjacent tower are used, then it is recommended that the quality of the tower-based data be established. The

comparison methods should follow those described for sodars above. Where RASS acoustic sources may interfere with the comparison sodar operation, care should be taken to identify potentially contaminated data.

RASS. Like the radar wind profiler, the evaluation of a RASS relies on a comparison to a reference instrument. The recommended method is to use a radiosonde sounding system to measure the variables needed to calculate virtual temperature (i.e., pressure, temperature, and humidity). Sufficient soundings should be made for comparisons during different times of the day to evaluate the performance of the system under different meteorological conditions. Data collected from the sonde should be volume averaged into intervals consistent with the RASS averaging volumes, and the values should be compared on a level-by-level and overall basis.

9.6.3 Standard Operating Procedures

Standard operating procedures (SOPs) should be developed that are specific to the operations at a given site. The purpose of an SOP is to spell out operating and QC procedures with the ultimate goal of maximizing data quality and data capture rates. Operations should be performed according to a set of well defined, written SOPs with all actions documented in logs and on prepared forms. SOPs should be written in such a way that if problems are encountered, instructions are provided on actions to be taken. At a minimum, SOPs should address the following issues:

- Installation, setup, and checkout
- Site operations and calibrations
- Operational checks and preventive maintenance
- Data collection protocols
- Data validation steps
- Data archiving

9.6.4 Operational Checks and Preventive Maintenance

Like all monitoring equipment, upper-air instruments require various operational checks and routine preventive maintenance. The instrument maintenance manuals should be consulted to determine which checks to perform and their recommended frequency. The quality and quantity of data obtained will be directly proportional to the care taken in ensuring that the system is routinely and adequately maintained. The site technicians who will perform preventive and emergency maintenance should be identified. The site technicians serve a crucial role in producing high quality data and thus should receive sufficient training and instruction on how to maintain the equipment. Some general issues related to operational checks and preventive maintenance should be addressed in the QAPP, including:

- Identification of the components to be checked and replaced
- Development of procedures and checklists to conduct preventive maintenance
- Establishment of a schedule for checks and preventive maintenance

- Identification of persons (and alternates) who will perform the checks and maintenance
- Development of procedures for maintaining spare components that need frequent replacement

Listed below are some key items to be included in the operational checklists for each of the different types of instrumentation. The list is by no means complete, but should serve as a starting point for developing a more thorough set of instrumentation checks.

- Safety equipment (first aid kit, fire extinguisher) should be inventoried and checked.
- After severe or inclement weather, the site should be visited and the shelter and equipment should be inspected.
- Computers should be routinely monitored to assure adequate disk space is available, and diagnosed to ensure integrity of the disk.
- A visual inspection of the site, shelter, instrument and its components should be made.
- Data should be backed up on a routine basis.
- If the remote sensors are operated during the winter, procedures for snow and ice removal should be developed and implemented, as needed.
- The clock time of the instruments should be monitored, and a schedule for updating the clocks established based on the timekeeping ability of the instrument.
- The antenna level and orientation of sodar, radar, RASS, and radio theodolite radiosonde systems should be verified periodically.
- The inside of the antennas/enclosures of the sodar, radar and RASS systems should be inspected and any leaves, dust, animals, insects, snow, ice, or other materials removed. Since the antennas are open to precipitation, drain holes are provided to allow water to pass through the bottom of the antennas. These holes should be periodically inspected and cleaned.
- Cables and guy wires securing the equipment should be checked to ensure that they are tight and in good condition.
- Antenna cables and connections should be inspected for signs of damage due to normal wear, moisture, or animal activities.
- For sodar systems, the site technician(s) should listen to assure that the system is transmitting on all axes and in the correct firing sequence. For three-axis systems, this is accomplished by listening to each antenna. For phased-array systems, this can be accomplished by standing away from the antenna in the direction of each beam and listening for relatively stronger pulses.
- The integrity of any acoustic enclosures and acoustic-absorbing materials should be inspected. Weathering of these items will degrade the acoustic sealing properties of the enclosure and reduce the performance.
- For a radar profiler with RASS, acoustic levels from the sound sources should be measured using a sound meter (ear protection is required) and readings should be compared with manufacturer's guidelines.

All operational checks and preventive maintenance activities should be recorded in logs and/or on appropriate checklists, (electronic and/or paper) which will become part of the documentation that describes and defends the overall quality of the data produced.

9.6.5 Corrective Action and Reporting

A corrective action program must have the capability to discern errors or defects at any point in an upper-air monitoring program. It is an essential management tool for coordination, QC, and QA activities. A workable corrective action program must enable identification of problems, and establish procedures for reporting problems to the responsible parties, tracing the problems to the source, planning and implementing measures to correct the problems, maintaining documentation of the results of the corrective process, and resolution of each problem. The overall documentation associated with the corrective action and reporting process will become part of the documentation that describes and defends the overall quality of the data produced. A sample correction form can be found in reference **[65]**.

9.6.6 Common Problems Encountered in Upper-Air Data Collection

Studies performed to date have indicated that the upper-air measurement systems described in this document can reliably and routinely provide high quality meteorological data. However, these are complicated systems, and like all such systems are subject to sources of interference and other problems that can affect data quality. Users should read the instrument manuals to obtain an understanding of potential shortcomings and limitations of these instruments. If any persistent or recurring problems are experienced, the manufacturer or someone knowledgeable about instrument operations should be consulted.

Radiosonde data are susceptible to several problems, including the following:

- **Poor ventilation.** Prior to launch, lack of ventilation of the sonde may result in unrepresentative readings of temperature and relative humidity (and thus dew-point temperature) at or near the surface.
- **Radio frequency (RF) interference.** RF interference may occasionally produce erroneous temperature, dew-point temperature, and relative humidity measurements, which appear as spikes in the data when plotted in a time series or profile plot.
- **Uncertainties in the tracking mechanism.** Uncertainties in a radio theodolite's tracking mechanism may produce unrealistic changes in the wind speed and direction, especially when the antenna's elevation angle is less than about 10°.
- **Tracking problems.** Tracking of radiosondes can be problematic within rainshafts or updrafts/downdrafts associated with thunderstorms.
- **Icing.** When a balloon encounters clouds and precipitation zones where the temperature is below freezing, ice can form on the balloon and cause it to descend. Once the balloon descends below the freezing level, the ice melts and the balloon re-ascends. This causes the balloon to fluctuate up and down around the freezing level, and produces unrepresentative wind and thermodynamic data.

- **Poor radio navigation reception.** Not all sites have good radio navigation reception. If this technique is used to track the radiosonde, poor reception can produce uncertainties in the wind data. Poor reception will not affect the thermodynamic data.
- **Low-level wind problems.** Often the first few data points in a radiosonde wind profile tend to have more uncertainty due to initial tracking procedures or difficulties (see Section 9.1 for more details).

Sodar data can be rendered problematic by the following:

- **Passive noise sources (also called fixed echo reflections).** Passive noise occurs when nearby obstacles reflect the sodar's transmitted pulse. Depending on atmospheric conditions, wind speed, background noise, and signal processing techniques, the fixed echoes may reduce the velocity measured along a beam(s) or result in a velocity of zero. This problem is generally seen in the resultant winds as a rotation in direction and/or a decrease in speed at the affected altitude. Some manufacturers offer systems that have software designed to detect fixed echoes and effectively reject their influence. To further decrease the effect of the fixed echoes, additional acoustic shielding can be added to the system antenna.
- **Active noise sources (ambient noise interference).** Ambient noise can come from road traffic, fans or air conditioners, animals, insects, strong winds, etc. Loud broad-spectrum noise will decrease the SNR of the sodar and decrease the performance of the system. Careful siting of the instrument will help minimize this problem.
- **Unusually consistent winds at higher altitudes**. Barring meteorological explanations for this phenomenon, the most common cause is a local noise source that is incorrectly interpreted as a “real” Doppler shift. These winds typically occur near the top of the operating range of the sodar. A good means of identifying this problem is to allow the sodar to operate in a listen-only mode, without a transmit pulse, to see if winds are still reported. In some cases it may be necessary to make noise measurements in the specific operating range of the sodar to identify the noise source.
- **Reduced altitude coverage due to debris in the antenna.** In some instances, particularly after a precipitation event, the altitude coverage of the sodar may be significantly reduced due to debris in the antennas. In three axis systems, drain holes may become plugged with leaves or dirt and water, snow, or ice may accumulate in the antenna dishes. Similarly, some of the phased-array antenna systems have the transducers oriented vertically and are open to the environment. Blocked drain holes in the bottom of the transducers may prevent water from draining. Regular maintenance can prevent this type of problem.
- **Precipitation interference.** Precipitation, mostly rain, may affect the data collected by sodars. During rainfall events, the sodar may measure the fall speed of drops, which will produce unrealistic winds. In addition, the sound of the droplets hitting the antenna can increase the ambient noise levels and reduce the altitude coverage.
- **Low signal to noise ratio (SNR).** Conditions that produce low SNR can degrade the performance of a sodar. These conditions can be produced by high background noise, low turbulence and near neutral lapse rate conditions.

Data from radar wind profiler systems can be affected by several problems, including the following:

- **Interference from migrating birds.** Migrating birds can contaminate radar wind profiler signals and produce biases in the wind speed and direction measurements **[105]**. Birds act as large radar "targets," so that signals from birds overwhelm the weaker atmospheric signals. Consequently, the radar wind profiler measures bird motion instead of, or in addition to, atmospheric motion. Migrating birds have no effect on RASS. Birds generally migrate year-round along preferred flyways, with the peak migrations occurring at night during the spring and fall months **[106]**.

- **Precipitation interference.** Precipitation can affect the data collected by radar profilers operating at 915 MHZ and higher frequencies. During precipitation, the radar profiler measures the fall speed of rain drops or snow flakes. If the fall speeds are highly variable during the averaging period (e.g., convective rainfall), a vertical velocity correction can produce erroneous data.

- **Passive noise sources (ground clutter).** Passive noise interference is produced when a transmitted signal is reflected off an object instead of the atmosphere. The types of objects that reflect radar signals are trees, elevated overpasses, cars, buildings, airplanes, etc. Careful siting of the instrument can minimize the effects of ground clutter on the data. Both software and hardware techniques are also used to reduce the effects of ground clutter. However, under some atmospheric conditions (e.g., strong winds) and at some site locations, ground clutter can produce erroneous data. Data contaminated by ground clutter can be detected as a wind shift or a decrease in wind speed at affected altitudes. Additional information is provided in references **[107]** and **[108]**.

- **Velocity folding or aliasing.** Velocity folding occurs when the magnitude of the radial component of the true air velocity exceeds the maximum velocity that the instrument is capable of measuring, which is a function of sampling parameters **[109]**. Folding occurs during very strong winds (>20 m/s) and can be easily identified and flagged by automatic screening checks or during the manual review.

RASS systems are susceptible to several common problems including the following:

- **Vertical velocity correction.** Vertical motions can affect the RASS virtual temperature measurements. As discussed in Section 9.1, virtual temperature is determined by measuring the vertical speed of an upward-propagating sound pulse, which is a combination of the acoustic velocity and the atmospheric vertical velocity. If the atmospheric vertical velocity is non-zero and no correction is made for the vertical motion, it will bias the temperature measurement. As a rule of thumb, a vertical velocity of 1 ms^{-1} can alter a virtual temperature observation by 1.6°C.

- **Potential cold bias.** Recent inter-comparisons between RASS systems and radiosonde sounding systems have shown a bias in the lower sampling altitudes **[110]**. The RASS virtual temperatures are often slightly cooler (-0.5 to -1.0°C) than the reference radiosonde data. Work is currently underway to address this issue.

9.7 Data Processing and Management (DP&M)

An important component of any upper-air meteorological monitoring program is the processing, QA, management, and archival of the data. Each of these components is briefly discussed in this section and some general recommendations for data processing and management are provided. Additional guidance on data issues is provided in Chapter 8 of this guidance document.

9.7.1 Overview of Data Products

For radiosonde systems, the final data products typically consist of one or more ASCII files that contain the reduced thermodynamic data (pressure, temperature, relative humidity, dewpoint, etc.) and wind speed and wind direction as a function of altitude. Some radiosonde data systems store the thermodynamic information in one data file and the wind information in another, whereas other systems combine the observations into a single data file. Regardless of the approach used, the files containing the reduced wind and thermodynamic observations should be considered the final data products produced by the radiosonde sounding systems. Depending on the type of equipment, additional files may be created that include data reported in formats specifically intended for use by the NWS or other organizations, information on site location, sampling parameters, balloon position, etc. Typically, one set of files is created per sounding, that is, data from multiple soundings are not merged together.

For the remote sensing systems (sodar, radar wind profilers, RASS), the final data products usually consist of one or more ASCII files containing the averaged profiles of winds or virtual temperatures as a function of altitude. Supporting information provided with the reduced data products may include other variables such as horizontal and vertical meteorological velocity components (u, v, w), averaged return power, SNR or some other measure of signal strength, estimates of turbulence parameters (σ_w, σ_θ), mixing depth, etc. Typically one set of files is produced per 24-hour sampling period. These data files should be considered the final data products produced by this class of upper-air monitoring system. Other (lower-level) information generated by these systems may include, for example, the Doppler moment data and raw Doppler spectra. The quantity of information produced by the remote sensing systems usually requires that the lower-level data be stored in a binary format to conserve disk space. These data should be archived for backup purposes and to support post-processing or additional analyses of periods of interest.

9.7.2 Steps in DP&M

Data processing, validation, and management procedures for an upper-air meteorological monitoring program would typically include the following steps, which should be described in the QAPP:

- Collection and storage on-site (as appropriate) of the “raw” signals from the upper-air sensors, followed by real-time processing of the “raw” data by the data acquisition system to produce reduced, averaged profiles of the meteorological variables. The reduced data are stored on the data acquisition system's computer, usually in one or more ASCII files.

- Transfer of the reduced data to a central data processing facility at regular intervals (e.g., daily). Once the data are received at the central facility, they should be reviewed by an experienced data technician as soon as possible to verify the operational readiness of the upper-air site. Backup electronic copies of the data should be prepared and maintained on-site and off-site.

Data collected by the remote sensing systems can usually be obtained by polling the data system at a site from the central facility using a personal computer, modem, and standard telecommunications software. Other options that are available for communications with a remote upper-air site include leased-line telephone service, local or wide area network (LAN, WAN) connections, Internet access, and satellite telemetry. For immediate turnaround of radiosonde data, the upper-air operator can transfer the sounding data to the central facility using a personal computer equipped with a modem and communications software. There must be a bulletin board system (BBS) operating at the central facility, or some other means provided to receive the data (e.g., via an Internet access). Alternatively, if a one- or two-day delay is acceptable, the operator can mail the sounding data to the data center.

Please note that the initial review of the data is not very time consuming, but it is an extremely important component of a successful upper-air program. It is at this stage that most problems affecting data quality or data recovery will be detected. If the upper-air data are not reviewed at regular, frequent intervals, the risk of losing valuable information increases. If the data are reviewed frequently, then problems can be detected and corrected quickly, often the same day, thereby minimizing data losses. At a minimum, the operational readiness of an upper-air monitoring site should be checked regularly. Likewise, maintaining backup copies of the data at each stage of processing is extremely important. Backup copies should be kept at the central data processing facility and at a separate, off-site location(s) to ensure that no data are damaged or lost.

- Additional post-processing is performed as required (e.g., reformatting the data using a different database format than that produced by the data acquisition system) to produce the version of the data that will be subjected to final quality control validation.

- At this stage, the data are usually said to be at “Level 0” quality control validation, meaning that they are ready for quality control screening and final validation.

- Quantitative screening of the data can be performed using quality control software to identify outliers or other observations that are possibly in error or otherwise appear questionable.

- A final review of the data should be performed by an experienced meteorologist who understands the methods used to collect the data and who is knowledgeable about the kinds of meteorological conditions expected to be revealed in the data.

This is the process that brings the data to what is usually referred to as “Level 1” quality control validation, meaning that the data have been subjected to a qualitative (and often quantitative) review by experts to assess the accuracy, completeness, and internal consistency of the data. At this stage, data that have been determined to be in error are usually removed from the database, and quality control flags are assigned to the data values to indicate their validity. It is also at this stage that final calibrations should be applied to the data as necessary, as well as any changes required as the result of the system audits. Additional screening of the data based on comparisons to other independent data sets may be performed, which is part of the process to bring the data to "Level 2" quality control.

- Some final processing may be necessary to convert the data to the format that will be used to submit the information to the final data archive.

Final documentation should be prepared that summarizes sampling strategies and conditions; describes the results of audits and any actions taken to address issues raised by the audits; identifies any problems that adversely affected data quality and/or completeness; and describes the contents and formats of the database. Typically, a copy (electronic and/or paper) of this documentation accompanies the submittal of the data to the final data archive. Once the above steps are completed, the data are ready to be submitted to the upper-air archive. Several options for creating an archive are available, ranging from a simple repository to complex database management systems (DBMS).

9.7.3 Data Archiving

Maintaining a complete and reliable data archive is an important component of a QAPP. Upper-air instruments, especially remote sensors, produce a large amount of data consisting of raw and reduced data. The amount of data from these upper-air sensors can require in excess of several gigabytes of computer storage space per site per year. A protocol for routinely archiving the data should be established.

Raw data are the most basic data elements from which the final data are produced. Archiving these data is important because at a later date the raw data may need to be reprocessed to account for problems, errors, or calibrations. In addition, future processing algorithms may become available to extract more information from the raw data. Raw data are generally stored on-site and should be archived as part of the operational checks. Data should be stored on convenient and reliable archive media such as diskette, tape, or optical disk. The primary archive should be stored in a central repository at the agency responsible for collecting the data. A second backup of the raw data should be made and stored off-site to ensure a backup if the primary data archive becomes corrupted or destroyed.

Reduced data, which are created from the raw data by averaging, interpolating, or other processing methods, should also be archived. Reduced data include hourly averaged winds and temperatures from remote sensors, and vertically averaged winds and thermodynamic data from radiosonde sounding systems. Data validation is performed on the reduced data to identify and flag erroneous and questionable data. Both the reduced and validated data should be routinely (e.g., weekly or monthly) archived onto digital media, with one copy stored onsite and a second copy stored offsite.

Other supporting information should be archived along with the data such as:

- Site and maintenance logs
- Audit and calibration reports
- Site information
- Log of changes made to the data and the data quality control codes

- Information that future users would need to decode, understand, and use the data
- Surface measurements and other relevant weather data

Data should be retained indefinitely because they are often used for modeling and analysis many years following their collection. Periodically, the integrity of the archive media should be checked to ensure that data will be readable and have not become corrupted. Data should be recycled by transfer from old to new media approximately every 5 to 10 years. If an archive is scheduled to be eliminated, potential users should be notified beforehand so that any important or useful information can be extracted or saved.

9.8 Recommendations for Upper-Air Data Collection

- *Suggested Data Quality Objectives (DOQs) for upper-air measurement systems are given in Table 9-5. DOQs for accuracy should be based on systematic differences; DOQs for precision should be based on the "comparability" statistic; DOQs for completeness should be based on percent data recovery.*
- *Site selection for upper-air measurement systems is best accomplished in consultation with vendors or users with expertise in such systems. Operators and site technicians of upper-air monitoring systems should receive appropriate training prior to or during system shake-down. Training should include instruction in instrument principles, operations, maintenance, troubleshooting, data interpretation and validation.*
- *System calibration and diagnostic checks of upper-air measurement systems should be performed at six month intervals, or in accordance with the manufacturer's recommendations, whichever is more frequent.*
- *Data capture for wind direction and wind speed from a sodar or radar wind profiler is defined somewhat differently than for more conventional instruments. The following definitions and requirements apply to databases generated by these instruments:*

  - *An averaging period (e.g., hourly) is considered valid if there are at least three valid levels of data for the period (independent of height).*

  - *If hourly average data are generated from sub-hourly intervals, the hourly values are considered valid if they consist for at least 30 minutes of valid sub- hourly data.*

  - *A valid level consists of all of the components needed to generate the horizontal wind vector.*
- *Remote sensing data should be reviewed at least weekly and preferably daily to assess the operational status of the system and to ensure that data are valid and reasonable.*

General recommendations for the processing, management, and archival of upper-air meteorological data include:

- *A consistent/standardized database format should be established and maintained, at a minimum for each individual monitoring program..*

- *The data archive should include raw, reduced, and validated data as well as other (low-level) data products, as appropriate (e.g., Doppler spectral moments data).*
- *The upper-air data should be validated to Level 1 before distribution.*
- *The data archive should be routinely backed up and checked for integrity.*
- *A secondary backup of the data should be kept at an alternate location, routinely checked for integrity, and periodically recycled onto new storage media.*

Table 9-1

Operating characteristics of upper-air meteorological monitoring systems.

VARIABLES	RADIOSONDE	DOPPLER SODAR	BOUNDARY LAYER RADAR WIND PROFILER	RASS
Measured	• p, T, RH • Vector winds (WS, WD)	• Vector winds (WS, WD) • u,v,w wind components	• Vector winds (WS, WD) • u,v,w wind components	• Virtual temperature (T_v) • w wind component
Derived	• Altitude • Moisture variables (dewpoint, mixing ratio, vapor pressure, etc.) • Potential temperature • Inversion base, top • Mixing depth	• Mixing depth • Dispersion statistics (σ_θ, σ_w)	• Mixing depth	• Inversion base, top • Mixing depth

Table 9-1 (continued)

Operating characteristics of upper-air meteorological monitoring systems.

PERFORMANCE CHARACTERISTICS	RADIOSONDE	DOPPLER SODAR	BOUNDARY LAYER RADAR WIND PROFILER	RASS
Minimum Altitude	10-150 m	10-30 m	90-120 m	90-120 m
Maximum Altitude	5-15 km	0.2-2 km	1.5-4 km	0.5-1.5 km
Vertical Resolution	5-10 m (p, T, RH) 50-100 m (winds)	5-100 m	60-100 m	60-100 m
Temporal Resolution	Integration time 5 sec.-2 min. Resolution: intermittent (time between soundings 1.5-12 hr.)	Integration time: 11-60 min. Resolution: continuous	Integration time 15-60 min. Resolution: continuous	Integration time 5-10 min. Resolution: intermittent (time between profiles 5 min-1 hr.)

Table 9-1 (continued)

Operating characteristics of upper-air meteorological monitoring systems.

PERFORMANCE CHARACTERISTICS	RADIOSONDE	DOPPLER SODAR	BOUNDARY LAYER RADAR WIND PROFILER	RASS
Systematic Difference	p: ± 0.5 mb T: ± 0.2°C RH: ± 10% U.V.: ± 0.5 to 1.0 ms^{-1}	WS: ± 0.2 to 1.0 ms^{-1} WD: ± 3-10°	WS: ± 1 ms^{-1} WD: ± 3-10°	± 1°C
Comparability	p (as height): ± 24 m T: ± 0.6°C T_d: ± 3.3°C WS: ± 3.1 ms^{-1} WD: ± 5-18°	WS: ± 0.5 to 2.0 ms^{-1} WD: ± 5-30°	WS: ± 2 ms^{-1} WD: ± 30°	± 1.5°C

Table 9-1 (continued)

Operating characteristics of upper-air meteorological monitoring systems.

OPERATIONAL ISSUES	RADIOSONDE	DOPPLER SODAR	BOUNDARY LAYER RADAR WIND PROFILER	RASS
Siting Requirements	• Requires relatively flat area approx. 30x30 m (allow sufficient space to launch balloon). • Absence of tall objects (trees, power lines, towers) that could snag weather balloon.	• Requires relatively flat area approx. 20x20 m (allow space for audit equipment, met tower). • Absence of active noise sources. • Absence of passive noise (clutter) targets. • No neighbors within about 100-500 m (depending on the sodar) who would be bothered by noise.	• Requires relatively flat area approx. 20x20 m (allow space for audit equipment, met tower). • Lack of radar clutter targets extending more than 5° above the horizon in antenna pointing directions; 15° otherwise.	• No neighbors within about 1000 m who would be bothered by noise.

Table 9-1 (continued)

Operating characteristics of upper-air meteorological monitoring systems.

OPERATIONAL ISSUES	RADIOSONDE	DOPPLER SODAR	BOUNDARY LAYER RADAR WIND PROFILER	RASS
Siting Logistics	• Balloon inflation shelter (e.g., small shed, tent, etc.) • Small (e.g., 8x12 ft.) equipment shelter, tied down, lightning protection • Security fence • 110/220v, 30 amp power service (usually required for air conditioning) • Communications service for data telemetry, voice. • May require FAA approval for operations at airports. • Instrument set-up can be completed in less than a day.	• Small (e.g., 8x12 ft.) equipment shelter, tied down, lightning protection • Security fence • 110/220v, 30 amp power service (usually required for air conditioning) • Communications service for data telemetry, voice. • Site will require 1-2 days to establish once trailer, power, etc. installed.	• Small (e.g., 8x12 ft.) equipment shelter, tied down, lightning protection. • Security fence • 110/220v, 30 amp power service (usually required for air conditioning) • Communications service for data telemetry, voice. • Site will require 2-3 days to establish once trailer, power, etc. installed.	• Add-on to radar profiler or sodar. No special additional logistical requirements. • Approx. 0.5-1 day needed to install and get operational.
Licensing	N/A	N/A	FCC license required	FCC license required

Table 9-1 (continued)

Operating characteristics of upper-air meteorological monitoring systems.

OPERATIONAL ISSUES	RADIOSONDE	DOPPLER SODAR	BOUNDARY LAYER RADAR WIND PROFILER	RASS
Routine Operations	• Intermittent sampling; number of soundings varies with measurement objectives. Typically, one sounding per day near sunrise is a minimum sampling frequency; this will characterize the early morning stable boundary layer. Additional soundings are useful at mid-morning (ABL development), mid-to-late afternoon (full extent of daytime ABL), and at night (nocturnal ABL). • Requires expendables for each sounding (radiosonde, balloon, helium, parachute, light for night operations). • Manned operations; requires an operator for each sounding.	• Continuous sampling • Automated, unmanned • Daily checks of operational status via remote polling.	• Continuous sampling • Automated, unmanned • Daily checks of operational status via remote polling.	• Intermittent sampling every hour, or more often as needed. • Automated, unmanned • Daily checks of operational status via remote polling.

Table 9-1 (continued)

Operating characteristics of upper-air meteorological monitoring systems.

OPERATIONAL ISSUES	RADIOSONDE	DOPPLER SODAR	BOUNDARY LAYER RADAR WIND PROFILER	RASS
Maintenance	• Bi-weekly barometer calibration checks • Daily back-ups • Back-up tracking device (e.g., optical theodolite) useful in case primary tracking system fails.	• Routine bi-weekly site inspections, servicing • Monthly on-site backups • Snow, ice removal in winter • Manufacturer-recommended spare parts	• Routine bi-weekly site inspections, servicing • Monthly on-site backups • Snow, ice removal in winter • Manufacturer-recommended spare parts	• Routine bi-weekly site inspections, servicing (follow SOP) • Monthly on-site backups • Snow, ice removal in winter • Manufacturer-recommended spare parts
Ground Truth	• Barometric pressure • T, RH • Radio theodolite oriented to true north, level	• Antenna orientation relative to true north • Antenna level	• Antenna orientation relative to true north • Antenna level	• Acoustic sources level • Antenna level

Table 9-1 (continued)

Operating characteristics of upper-air meteorological monitoring systems.

OPERATIONAL ISSUES	RADIOSONDE	DOPPLER SODAR	BOUNDARY LAYER RADAR WIND PROFILER	RASS
QA	• Acceptance test • Standard operating procedure (SOP) • Routine comparison with 10 m tower data • Annual system audit • Annual performance audit of ground truth instruments (e.g., barometer).	• Acceptance test • Standard operating procedure (SOP) • Routine comparison with 10 m tower data • Annual system audit • Annual intercomparison using complementary upper-air system.	• Acceptance test • Standard operating procedure (SOP) • Routine comparison with 10 m tower data • Annual system audit • Annual intercomparison using complementary upper-air system.	• Acceptance test • Standard operating procedure (SOP) • Routine comparison with 10 m tower data • Annual system audit • Annual intercomparison using complementary upper-air system.
Training	• Operators trained to perform soundings; usually requires a few days of classroom and on-site training. • Final data review should be performed by a meteorologist familiar with the instrument systems used.	• Site technicians trained to service equipment; usually requires 1-2 days of on-site training. • Data processing technician trained to poll site, retrieve data, review operational status, troubleshoot problems. • Final data review should be performed by a meteorologist familiar with the instrument systems used.	• Site technicians trained to service equipment; usually requires 1-2 days of on-site training. • Data processing technician trained to poll site, retrieve data, review operational status, troubleshoot problems. • Final data review should be performed by a meteorologist familiar with the instrument systems used.	• Site technicians trained to service equipment; usually requires 1-2 days of on-site training. • Data processing technician trained to poll site, retrieve data, review operational status, troubleshoot problems. • Final data review should be performed by a meteorologist familiar with the instrument systems used.

Table 9-1 (continued)

Operating characteristics of upper-air meteorological monitoring systems.

OPERATIONAL ISSUES	RADIOSONDE	DOPPLER SODAR	BOUNDARY LAYER RADAR WIND PROFILER	RASS
Data Processing	• Reduce data on-site, ensure proper operations. • Bring final data to at least Level 1 QC validation (see text). • 100 Kb - 1 Mb/sounding	• Use vertical velocity correction (see text). • Bring final data to at least Level 1 QC validation (see text). • 100 Kb/day	• Use vertical velocity correction (see text). • Bring final data to at least Level 1 QC validation (see text). • 150 Kb-1 Mb /day	• Use vertical velocity correction (see text). • Bring final data to at least Level 1 QC validation (see text). • 20 Kb/day

Table 9-1 (continued)

Operating characteristics of upper-air meteorological monitoring systems.

STRENGTHS	RADIOSONDE	DOPPLER SODAR	BOUNDARY LAYER RADAR WIND PROFILER	RASS
	• *In situ* measurements • Deep profiles, high data recovery rates to extended altitudes. • Measures atmospheric moisture • Data compatible with global upper-air network.	• Samples lower parts of ABL • Continuous • Smaller sample volumes (finer vertical resolution). • Fixed reference frame • Useful in complex terrain to measure winds at plume heights.	• Samples through full extent of ABL • Continuous • Data recovery not affected by high wind speeds. • Performance improves with increasing RH. • Fixed reference frame	• Provides high time resolution of temperature profiles in ABL. • Measures T_v • Fixed reference frame

Table 9-1 (continued)

Operating characteristics of upper-air meteorological monitoring systems.

LIMITATIONS	RADIOSONDE	DOPPLER SODAR	BOUNDARY LAYER RADAR WIND PROFILER	RASS
	• Not continuous • Manned operations • Lowest altitude at which good winds are reported can be 200-300 m above ground level depending on tracking system, signal strength, operator training. • Balloon drifts with wind, producing moving reference frame for measurements. • Wet bulb not as reliable as carbon hygristor for measuring frost point. • Launching problematic during thunderstorms. • Subject to icing. • LORAN radio navigation system being discontinued.	• Altitude coverage may not extend through full depth of daytime ABL. • Altitude coverage may be limited at night due to nocturnal inversion. • Interference from active noise sources. • Interference from precipitation. • High wind speeds reduce altitude coverage. • Performance degrades (lower altitude coverage) with low RH. • Nuisance effects from transmitted noise. • Multiple component statistics such as σ_θ not reliable.	• Interference from precipitation. • Interference from migrating birds. • Lowest altitude sampled ~100 m above ground level. • May be subject to ground clutter. • Larger sample volumes (coarser vertical resolution). • Performance degrades (lower altitude coverage) at low RH.	• T_v may need to be converted to T. • Nuisance effects from transmitted noise. • Altitude coverage may not extend through full depth of daytime ABL. • Error sources exist that can produce biases on the order of 0.5-1° C, which may be corrected during post-processing.

10. REFERENCES

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16. ABSTRACT

This document provides EPA's guidance for the collection and processing of meteorological data for use in regulatory dispersion modeling and is the basis for the regulatory review of proposed meteorological monitoring plans by the EPA Regions and the States. The document contains comprehensive and detailed guidance for meteorological measurement programs, covering the initial design and siting of a system, through data recording and processing.

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REPRESENTATIVE METEOROLOGICAL DATA FOR AERMOD: A CASE STUDY OF WRF-EXTRACTED DATA VERSUS NEARBY AIRPORT DATA

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1. INTRODUCTION

Historically, meteorological data for near-field air dispersion modeling (such as with AERMOD) has come primarily from the closest airport station to the facility being modeled, or from purpose-built “onsite” stations located at or near the facility. In areas where nearby observational data is not available or where meteorological conditions change rapidly with distance, these typical data sources become less representative of the actual facility location, introducing substantial error.

Recent changes to U.S. EPA’s Appendix W air dispersion modeling document have opened the possibility of increased use of mesoscale meteorological model data (WRF or MM5) as an alternative source of meteorological data for near-field air dispersion modeling (U.S. EPA 2017). Site-specific mesoscale model data is promising in that it has the potential to eliminate most of the distance-based representativeness error described above. However, this comes at the cost of introducing forecast error from the mesoscale model, which will typically be larger than the observation error of a perfectly-placed surface meteorological station. Weighing the representativeness error of a distant airport meteorological station against that of an imperfect mesoscale meteorological model is a necessary but potentially difficult task in deciding which meteorological data source is most representative of a given location.

This study examines the relative magnitude of the errors in these two meteorological data sources in two case studies: one using a facility located in relatively flat terrain, and another using a facility located in complex terrain. In both cases, an on-site meteorological station is used as “truth”. Meteorological data taken from a moderately distant airport station and from the closest grid cell of a WRF model run are compared to the on-site station’s observations to quantify the relative error of each. AERMOD model runs are then carried out using each data source (site specific “truth”, distant airport, and mesoscale model) to quantify the extent to which error in each meteorological source translates into dispersion model result error.

2. METHODS

For the simple terrain case study, the Wallisville Road air quality monitor location near Houston, Texas (AQS: 48-201-0617) was used as the source location. Onsite data from the monitor was used as an approximation of “true” meteorological conditions at the site. NWS airport meteorological data was taken from George Bush Intercontinental Airport (KIAH), 40 km to the northwest of the site. As the closest and most representative NWS station to Wallisville Road, this is the site that would most likely have been used in a typical real-world regulatory modeling application. The WRF dataset was extracted from the nearest gridpoint of a 12 km resolution national WRF simulation obtained from U.S. EPA (29.871N, 94.960W). The locations of all three sites are shown in Figure 1. Data from January-December 2007 was used for the simple terrain case study, as this was the most recent year available from all three data sources.

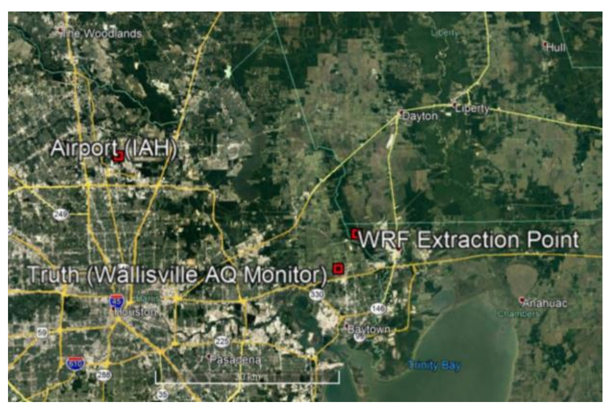

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Fig. 1. Location of the three meteorological data sources (Truth, Airport, and WRF) for the simple terrain case.

For the complex terrain case study, sources were placed at the location of the Wamsutter, Wyoming air quality monitor (AQS: 56-037-0200), which was used to approximate the "true" meteorological conditions at the site. NWS airport data was taken from the Rock Springs, Wyoming Airport (KRKS), 86 km to the west of the site. Of the available NWS station data in this area, Rock Springs is the most representative of the Wamsutter site, but significant distance and differences in elevation and surrounding topography make it less than ideally representative of Wamsutter. This situation, in which the best-available NWS data is far from ideal in representing a project site, is a common occurrence faced by industry and regulators, particularly in areas of the Mountain West where topography and widely-spaced airports mean many possible source locations do not have representative meteorological data readily-available. The WRF dataset for the complex terrain case was extracted from the nearest gridpoint of a 12 km resolution national WRF simulation obtained from U.S. EPA (41.728N, 107.994W). The locations for all three sites are shown in Figure 2. Data from January-December 2008 was used for the complex terrain case study, as this was the most recent year available from all three data sources.

Fig. 2. Location of the three meteorological data sources (Truth, Airport, and WRF) for the complex terrain case.

All six datasets were processed using the latest version of AERMET according to standard U.S. EPA regulatory guidance and recommendations. The WRF data was extracted into simulated surface and onsite point data files using U.S. EPA's MMIF tool, and was then processed through AERMET to ensure as much consistency as possible with the "truth" and airport datasets. For the airport stations, 1-minute wind data was incorporated using AERMINUTE, and all datasets used the same 0.5 m/s wind threshold, with winds below that threshold being treated as calm hours (and thus being ignored by AERMOD). AERSURFACE was used to analyze the land use for the "truth" and airport datasets, while the WRF land use as extracted by MMIF was used for the WRF datasets.

The ADJ_U* option in AERMET, which is intended to offset AERMOD's tendency to over-predict concentrations from near-ground sources under stable, low wind conditions, was applied to the airport and WRF meteorological datasets, in accordance with U.S. EPA guidance U.S. EPA 2016a,b). It was not applied to the "truth" datasets due to the fact that the onsite stations used as "truth" include hourly σ_Θ (standard deviation of horizontal wind direction) data. U.S. EPA guidance on use of ADJ_U* recommends that it not be used if direct measurements of turbulence are available. ADJ_U* operates by increasing the surface friction velocity (u*) used by AERMET for the stable atmosphere, low wind speed hours in which AERMOD otherwise would tend to over-predict ground-level concentrations (U.S. EPA 2016a).

AERMOD simulations were performed using each meteorological dataset. Because the impacts of different types of sources can be determined by different meteorological regimes and variables, two different sources were modeled – a ground-level volume source, and a 35 meter stack with 350 K exit temperature, 25 m/s exit velocity, and 1 m diameter. A receptor grid typical of standard regulatory modeling applications was used, with a small receptor-free buffer area around the source location (representing the area inside a facility fenceline), and three tiers of receptors:

-100 m spacing for the first 1 km past the fenceline
-500 m spacing from 1-5 km past the fenceline
-1000 m spacing from 5-10 km past the fenceline

Terrain data was incorporated in the modeling via the AERMAP utility. Building downwash was not incorporated. AERMOD simulations were carried out for a one-year period using the six datasets. Regulatory default settings were used in AERMOD, and maximum 1-hour, 24-hour, and annual concentrations were modeled.

3. RESULTS

3.1 Comparison of Meteorological Data

In the simple terrain case, generally similar wind patterns were present in all three meteorological datasets. Wind roses for the three datasets are shown in Figure 3. The most notable difference in patterns of wind direction was the increased frequency of the prevailing SSE/SE wind pattern in the WRF dataset. SSE/SE winds were present 32% of the time in the WRF dataset, compared to 25% of the time in the Airport dataset and 26% of the time in the Truth dataset. Low wind speeds were less frequent in the WRF data (12.6% < 1.54 m/s) and particularly in the Airport data (7.0% <1.54 m/s) compared to the Truth dataset (23.7% <1.54 m/s). In addition to underrepresenting low winds, the Airport dataset also overrepresented high wind speeds relative to the Truth dataset.

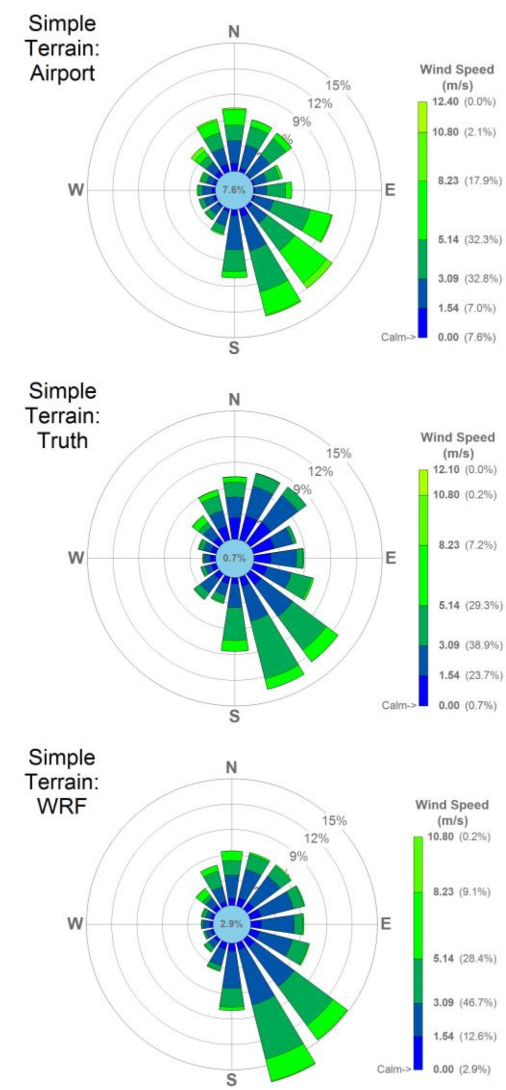
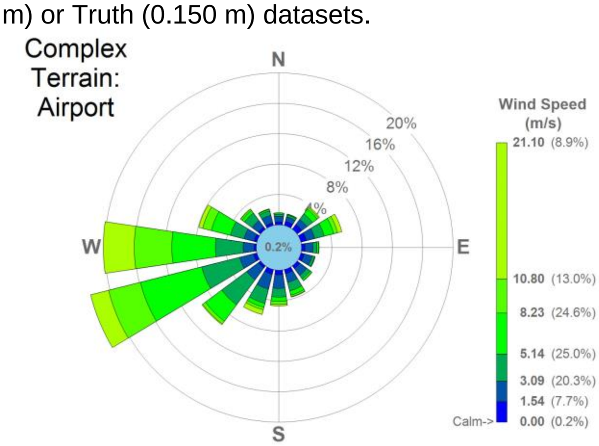


Fig. 3. Comparison of wind roses for airport, truth, and WRF datasets in the simple terrain case.

This is consistent with the relatively low surface roughness typically found at airports. The surface roughness corresponding to the prevailing wind in this case was in fact lower for the Airport data (0.045 m) than for the WRF (0.168 m) or Truth (0.159 m) datasets. Similarly, average wind speed was highest in the Airport data (3.5 m/s compared to 2.9 m/s in the WRF data and 2.8 m/s in the Truth data). Calm winds, which AERMOD does not model, were most common in the Airport data (7.6%, versus 2.9% in the WRF data and 0.7% in the Truth data).

In the complex terrain case, major differences in wind speed and direction patterns were evident between the three datasets. Wind roses for the three datasets are shown in Figure 4. The Truth dataset shows a prevailing WNW-WSW wind that represents 36% of hours, but a wide range of other wind directions are also common. The WRF dataset captures some of this variability (WNW-WSW represents 35% of hours, but a frequent SE wind in the Truth data is not seen in the WRF data). The airport data gives much heavier weight to the prevailing WNW-WSW wind (51% frequency) and underrepresents other wind directions.

High winds are somewhat more frequent in the Airport dataset than in the Truth dataset. The WRF dataset underrepresents high winds, possibly as a result of insufficient grid resolution to resolve terrain- or thunderstorm-induced winds. As in the simple terrain case, average Airport wind speeds (5.6 m/s) were higher than average WRF (4.0 m/s) or Truth (5.3 m/s) wind speeds, and average surface roughness was lower for the Airport dataset (0.063 m) than for the WRF (0.249 m) or Truth (0.150 m) datasets.



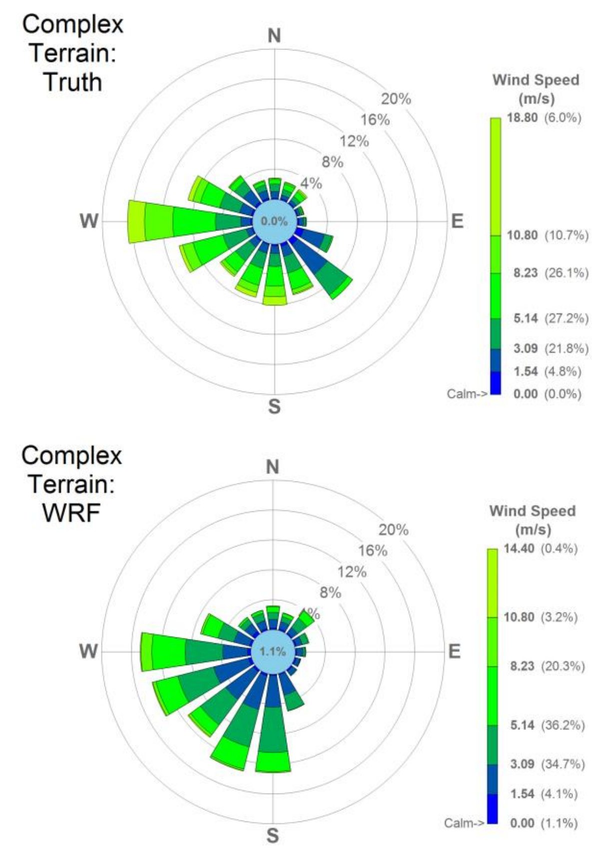


Fig. 4. Comparison of wind roses for airport, truth, and WRF datasets in the complex terrain case.

3.2 Comparison of AERMOD Results

A summary of peak 1- hour, 24-hour, and annual average concentrations is provided in Table 1. The concentration data is normalized so the “Truth” results have a value of 1.0. Thus, higher values represent over-prediction relative to the “Truth”, and lower values represent under-prediction. Results are presented for each case (simple and complex terrain), and for the tall stack source and ground level source.

In the simple terrain case, the WRF dataset consistently over-predicted peak concentrations for the tall stack source and consistently under-predicted peak concentrations for the ground level source. The Airport dataset over-predicted concentrations for the tall stack in the 24-hour and annual periods, but under-predicted the maximum 1-hour concentrations. As with the WRF data, the Airport dataset consistently under-predicted concentrations for the ground level source. With the exception of the ground level source annual averaging period, the WRF dataset consistently produced more conservative results than the Airport dataset.

In the complex terrain case, the tall stack results were more mixed, but the pattern of ground level results consistently being under-predicted by both the Airport and WRF datasets was present.

Maximum Annual Concentration				
Source Group	Simple Terrain		Complex Terrain	
	Airport	WRF	Airport	WRF
Tall Stack	1.34	1.67	1.28	0.80
Ground Level	0.52	0.45	0.50	0.39
Maximum 1-Hour Concentration				
Source Group	Simple Terrain		Complex Terrain	
	Airport	WRF	Airport	WRF
Tall Stack	0.85	1.29	0.85	1.21
Ground Level	0.14	0.16	0.21	0.29
Maximum 24-Hour Concentration				
Source Group	Simple Terrain		Complex Terrain	
	Airport	WRF	Airport	WRF
Tall Stack	1.37	1.70	0.86	1.10
Ground Level	0.37	0.42	0.24	0.22

Table 1. Summary of maximum ground level concentrations in each case, normalized so the “Truth” concentration is 1.00.

Normalized Bias (1-Hour Concentrations)				
Source Group	Simple Terrain		Complex Terrain	
	Airport	WRF	Airport	WRF
Tall Stack	-20%	30%	2%	-12%
Ground Level	-81%	-63%	-45%	-35%
Normalized RMSE (1-Hour Concentrations)				
Source Group	Simple Terrain		Complex Terrain	
	Airport	WRF	Airport	WRF
Tall Stack	34%	49%	47%	38%
Ground Level	124%	110%	126%	119%

Table 2. Bias and RMSE, normalized based on the average “Truth” concentration.

Normalized bias and RMSE were also calculated for 1-hour concentrations, treating the modeled onsite calculations as “Truth”. These results are shown in Table 2. Similar to the findings for maximum concentrations, both the Airport and WRF datasets showed a consistent under-prediction bias for the ground level source, and lower bias for the tall stack source. Normalized RMSE for the WRF dataset was lower than for the Airport dataset with the exception of the simple terrain, tall stack case.

Q-Q plots of 1-hour concentration data are presented in Figure 5 (simple terrain) and Figure 6 (complex terrain). The general trends of error and bias described above can be seen.

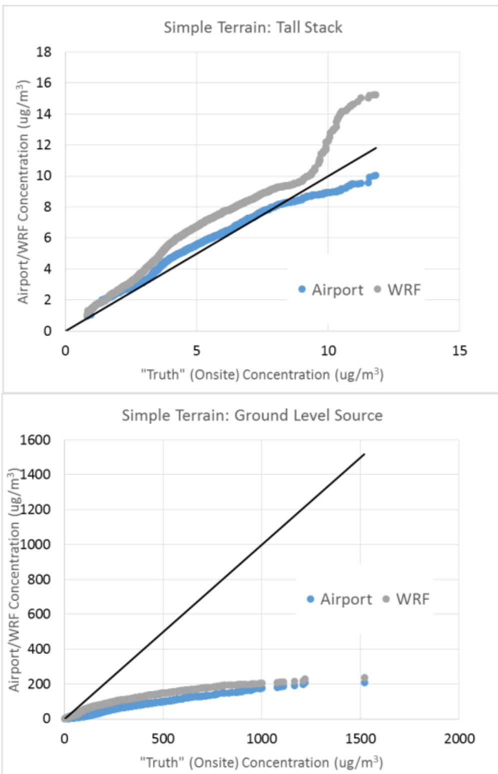
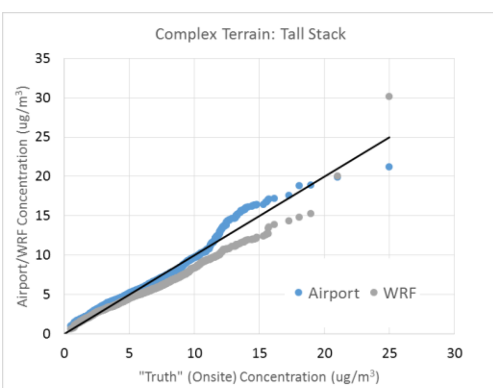


Fig. 5. Q-Q plots for 1-hour concentrations resulting from each source type in the simple terrain case.



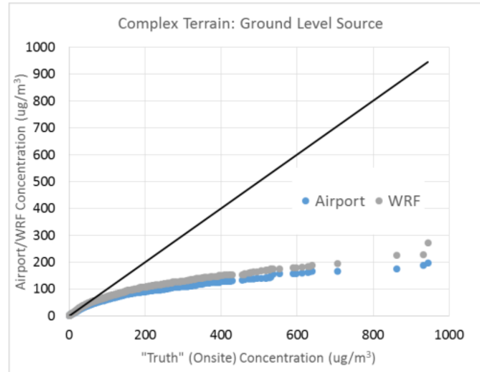


Fig. 6. Q-Q plots for 1-hour concentrations resulting from a tall stack and ground level source in the complex terrain case.

4. DISCUSSION

4.1 Effectiveness of WRF-Derived Meteorological Data versus Traditional Airport Data

This study examined two cases: a simple terrain case in which the airport meteorological data typically used in regulatory AERMOD modeling would generally be considered appropriate and representative of the modeled source location, and a complex terrain case in which the best available airport meteorological data is quite distant (80 km) and not clearly representative due to different terrain than the actual source location.

For each case, three sets of AERMOD modeling was performed: using onsite meteorological data from each source location, using data from the airport that would typically be used in a regulatory modeling application, and using data derived from a 12 km resolution WRF model simulation. The AERMOD results using Airport and WRF data were each compared to the results using onsite data, considering the results using onsite data to be “Truth” because onsite data is the preferred meteorological data source both on a scientific basis and in the eyes of U.S. EPA regulatory guidance.

AERMOD model accuracy when using WRF-derived data was approximately equal to accuracy when using Airport meteorological data. This was true both for the simple terrain case in which the Airport would generally be considered a representative data source, and for the complex terrain case in which the Airport might not be considered an acceptable data source. The details of the relative performance of the WRF-derived and Airport datasets varied among source type, averaging period, and assessment metric, but they were broadly equal in quality. Given that RMSE for the WRF-derived data was consistently lower than the Airport data in the complex terrain case, it appears that, as would be expected, the benefits of using WRF data over Airport data increase as the degree to which the Airport location is representative of the source location decreases. These findings that AERMOD performance using WRF data is at least as good as AERMOD performance using Airport data are consistent with the findings of U.S. EPA's evaluation of WRF and MMIF-derived meteorological data performance (U.S. EPA 2016c).

4.2 Applicability of ADJ_U to Onsite Meteorological Datasets That Include Partial Turbulence Data*

Possibly the most interesting results in this study actually did not relate to the intended study objective of comparing AERMOD performance using Airport and WRF-derived meteorological data, but to the poor performance of both Airport and WRF data when modeling a ground-level source. Both data sources resulted in large under-predictions of maximum ground level concentrations when compared to AERMOD results using onsite meteorological data.

The cause of this large discrepancy appears to be due to the decision, made in accordance with U.S. EPA regulatory guidance, to use the ADJ_U* AERMET option when processing the Airport and WRF-derived datasets, but not when processing the onsite "Truth" datasets. More discussion of ADJ_U* can be found in Section 1.

The large change in AERMOD performance for ground level sources seen in the cases where ADJ_U* is applied is not unusual, and is in keeping with the findings of U.S. EPA's thorough evaluation of the benefits of ADJ_U*. Thus, unless the multiple case studies used in U.S. EPA's evaluation of ADJ_U* are somehow fundamentally different than the two cases examined here, it is likely the case that for the ground level source in this case, the low concentrations produced by the WRF and Airport datasets are in fact more accurate than the high concentrations produced by the "Truth" onsite datasets. Recall that in this case, the decision not to apply ADJ_U* to the onsite datasets was a regulatory "gray area": ADJ_U* is supposed to be applied when turbulence data is not measured at the onsite station, but is not supposed to be applied when turbulence data is available. In this case, a small amount of turbulence data (σ_θ) was available. Thus, this case would seem to suggest that when σ_θ is the only available turbulence data at an onsite station, ADJ_U* should in fact be applied, as the AERMOD results will otherwise be likely to produce the over-predictions of concentrations for ground level sources that are found when modeling without any observed turbulence data. Figure 7 shows a Q-Q plot with ADJ_U* applied to the onsite "Truth" data for the simple terrain ground level source case that, when compared to the same plot in Figure 5 that did not include ADJ_U*, shows that performance of both WRF and Airport data is comparable to the onsite "Truth" data if ADJ_U* is applied to the onsite data.

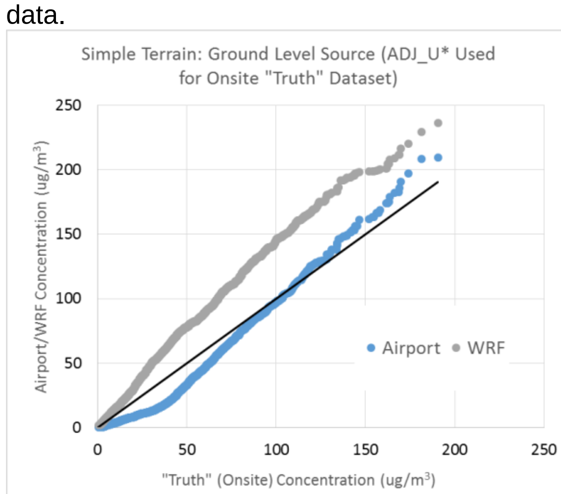


Fig. 7. Q-Q plots for 1-hour concentrations resulting from a ground level source in the simple terrain case, with ADJ_U* applied to the onsite ("Truth") meteorological dataset.

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U.S. EPA, 2016: Guidance on Use of the Mesoscale Model Interface Program (MMIF) for AERMOD Applications. EPA-454/B-16-003. Online: https://www3.epa.gov/ttn/scram/appendix_w/2016/MMIF_Guidance.pdf

U.S. EPA, 2016: Evaluation of Prognostic Meteorological Data in AERMOD Applications. EPA-4354/R-16-004. Online: https://www3.epa.gov/ttn/scram/appendix_w/2016/MMIF_Evaluation_TSD.pdf

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Air Dispersion Modeling Guidelines for Arizona Air Quality Permits

PREPARED BY:

AIR QUALITY PERMIT SECTION

AIR QUALITY DIVISION

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

September 23, 2013

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ACRONYMS AND ABBREVIATIONS

AAAC	Acute Ambient Air Concentrations
AAB	Ambient Air Boundary
AAC	Arizona Administrative Code
ADEQ	Arizona Department of Environmental Quality
AERMAP	Terrain data preprocessor for AERMOD
AERMET	Meteorological data preprocessor for AERMOD
AERMIC	American Meteorological Society/Environmental Protection Agency Regulatory Model Improvement Committee
AERMOD	AMS/EPA Regulatory Model
AERSCREEN	Screening version of AERMOD
AERSURFACE	Surface characteristics preprocessor for AERMOD
AIWG	AERMOD Implementation Workgroup
AMS	American Meteorological Society
AQCR	Air Quality Control Region
AQRV	Air Quality Related Value
ARM	Ambient Ratio Method
ASOS	Automated Surface Observing Systems
BPIP	Building Profile Input Program
CAA	Clean Air Act
CAAC	Chronic Ambient Air Concentrations
CALMET	Meteorological data preprocessor for CALPUFF
CALPOST	Postprocessor for CALPUFF
CALPUFF	California Puff Model
CASTNET	Clean Air Status and Trends Network
DEM	Digital Elevation Model
EPA	Environmental Protection Agency
FLAG	Federal Land Managers' Air Quality Related Values Work Group
FLM	Federal Land Manager
GAQM	Guideline on Air Quality Models
GEP	Good Engineering Practice
HAP	Hazardous Air Pollutants
IMPROVE	Interagency Monitoring of Protected Visual Environments
ISCST3	Industrial Source Complex, Short Term Ver. 3
IWAQM	Interagency Workgroup on Air Quality Modeling
MACT	Maximum Achievable Control Technology
MM5	Penn State/NCAR Fifth Generation Mesoscale Model
MMIF	Mesoscale Model Interface Program
MRLC	Multi-Resolution Land Characteristics
NAA	Nonattainment Area
NAAQS	National Ambient Air Quality Standards
NACAA	National Association of Clean Air Agencies
NCDC	National Climatic Data Center
NED	National Elevation Dataset
NWS	National Weather Service

OAQPS	Office of Air Quality Planning and Standards
OBODM	Open Burn/Open Detonation Model
OLM	Ozone Limiting Method
PRIME	Plume Rise Model Enhancements
PSD	Prevention of Significant Deterioration
PVMRM	Plume Volume Molar Ratio Method
SCRAM	EPA Support Center for Regulatory Air Models
SER	Significant Emission Rate
SIA	Significant Impact Area
SIL	Significant Impact Level
SIP	State Implementation Plan
SMC	Significant Monitoring Concentration
SoDAR	Sonic Detection And Ranging
USGS	U.S. Geological Survey
UTM	Universal Transverse Mercator
WRF	Weather Research and Forecasting

1 INTRODUCTION

This guidance document has been developed by the Air Quality Division (AQD) of the Arizona Department of Environmental Quality (ADEQ) to document air quality modeling procedures for air quality permit applications for sources located in Arizona under ADEQ jurisdiction. This guidance provides assistance to applicants required to perform modeling analyses to demonstrate that the air quality impacts from new and existing sources protect public health, general welfare, physical property, and the natural environment. This guideline is not intended to supersede statutory or regulatory requirements or more recent guidance of the state of Arizona or the U.S. Environmental Protection Agency (EPA).

It is assumed that the reader of these guidelines has a basic knowledge of modeling theory and techniques. At a minimum, individuals responsible for conducting an air quality modeling analysis should be familiar with the following documents:

- *Guideline on Air Quality Models* (GAQM) as codified in 40 CFR 51, Appendix W (U.S. EPA, 2005);
- *Draft New Source Review Workshop Manual* (U.S. EPA, 1990);
- *Screening Procedures for Estimating the Air Quality Impact of Stationary Sources* (U.S. EPA, 1992a);
- Guidance and clarification memoranda issued by the EPA Office of Air Quality Planning and Standards (OAQPS);
- Guidance issued by EPA Region 9; and
- User's guides for each dispersion model.

This publication replaces the previous edition of ADEQ's *Modeling Guidelines* (ADEQ, 2004). This guidance clarifies issues described in EPA documents, facilitates development of an acceptable modeling analysis, and assists ADEQ in expediting the permit review process. The guidelines also outline additional modeling requirements specific to ADEQ.

While ADEQ has attempted to address as many issues as possible, each modeling analysis is still treated on a case-by-case basis. Therefore, the applicant should work closely with ADEQ staff to ensure that all modeling requirements are met. If the applicant can demonstrate that techniques other than those recommended in this document are more appropriate, then AQD may approve their use. ADEQ reserves the right to make adjustments to the modeling requirements of each permit application on a case-by-case basis.

This document will be amended periodically to incorporate new modeling guidance and changes to regulations.

1.1 Overview of Regulatory Modeling

Air quality modeling is utilized to predict ambient impacts of one or more sources of air pollution. Equations and algorithms representing atmospheric processes are incorporated into various dispersion models. The equations and algorithms used in the models are based on both known atmospheric processes and empirical data. ADEQ uses the results of modeling analyses to determine if a new or existing source of air pollutants complies with state and federal maximum ambient concentration standards and guidelines. Air quality models are useful in properly designing and configuring sources of pollution to minimize ambient impacts.

The most commonly used air quality models for regulatory applications generally fall into two categories: dispersion models and photochemical grid models. Dispersion models are typically used in the permitting process to estimate the concentration of pollutants at specified ground-level receptors surrounding an emissions source. Photochemical grid models are typically used in regulatory or policy assessments to simulate the impacts from all sources by estimating pollutant concentrations and deposition of both inert and chemically reactive pollutants over large spatial scales. This guidance document addresses dispersion modeling as a regulatory tool.

Owing to the intrinsic uncertainty of air quality modeling, a modeled prediction alone does not necessarily indicate a real-world pollution condition. However, a modeled prediction of an exceedance of a standard or guideline may indicate the possibility of potential real-world air quality violations. The impacts of new sources that have not been constructed can only be determined through air quality modeling. Moreover, monitoring data normally are not sufficient as the sole basis for demonstrating the adequacy of emission limits for existing sources because of the limitations in the spatial and temporal coverage. Therefore, air quality models have become a critical analytical tool in air quality assessments. In particular, they are widely used as a basis to modify allowable emission rates, stack parameters, operating conditions, or to require state implementation plan review for criteria pollutants.

1.2 Purpose of an Air Quality Modeling Analysis

An air quality modeling analysis is used to determine that criteria pollutants or hazardous air pollutants emitted from a source will not cause or significantly contribute to a violation of any National Ambient Air Quality Standard (NAAQS), or Prevention of Significant Deterioration (PSD) increment, or Arizona Acute/Chronic Ambient Air Concentrations (AAAC and CAAC) for listed hazardous air pollutants (HAPs). An overview of modeling analyses required by ADEQ for non-PSD sources is described in Section 5. An overview of PSD modeling analyses is provided in Section 6. An overview of HAPs modeling analyses is provided in Section 7.7. Air quality modeling analyses may also be required to:

- Determine whether air quality monitoring is required and appropriately locate air quality and/or meteorological monitors,
- Determine the impacts on Class I and Class II Areas as a result of emissions from new or modified sources,
- Determine if, for a PSD source located within 10 kilometers of a federal Class I Area, the source's net emissions increase has an impact of 1 $\mu g/m^3$ (24-hour average) or more,
- Determine if, for any pollutant, a concentration will exist that may pose a threat to public health or welfare or unreasonably interfere with the enjoyment of life or property (e.g. odor), and/or
- Perform a human health or ecological risk assessment.

1.3 Authority for Modeling

Arizona Revised Statutes (A.R.S.) §49-422, describes the powers of the ADEQ Director related to the quantification of air contaminants. Arizona Administrative Code (A.A.C.) R18-2-407 requires air dispersion modeling for new major sources and major modifications to existing sources. On a case-by-case basis, ADEQ may conduct or request that applicants perform modeling analyses for both minor sources and minor modifications.

ADEQ is currently seeking approval of a rule package from the Environmental Protection Agency to update its minor New Source Review program. Upon approval by EPA, A.A.C. R18-2-334 will provide an opportunity to Permittees to address minor NSR changes by conducting a NAAQS modeling exercise or to conduct a Reasonable Available Control Technology (RACT) analysis. Notwithstanding the Permittee's election to conduct a RACT analysis, the Director may subject the Permittee to conduct a NAAQS analysis if a source or a minor NSR modification has the potential to contribute to a violation of the NAAQS.

1.4 Acceptable Models

In general, ADEQ adheres to EPA's *Guideline on Air Quality Models (GAQM)* codified in 40 CFR 51, Appendix W, to determine acceptable models for use in air quality impact analyses (U.S. EPA, 2005). This document provides guidance on appropriate modeling applications. As new models are accepted by EPA, the *Guideline on Air Quality Models* is updated.

A "preferred model" as specified in the GAQM is acceptable for the type of regulatory modeling for which it is designed. For example, the preferred near-field (less than 50 kilometers from the source) dispersion model for industrial sources is the American Meteorological Society (AMS)/EPA Regulatory Model (AERMOD) and the preferred long-range transport (beyond 50 kilometers from the source) dispersion model is California Puff Model (CALPUFF). First tier models also include BLP and Cal3QHC. A second tier of models are the "alternative models" as specified in GAQM. These models could be used in situations where ADEQ has found them to be more appropriate than a preferred model. However, the applicant must seek ADEQ approval to use any alternative model. ADEQ reserves the right to evaluate the use of alternative models on a case-by-case basis. Additionally, depending on the situation, the model evaluation may require the approval by EPA Region 9 and/or be subject to public review.

More information regarding dispersion modeling, including models available for download, is available at EPA's Support Center for Regulatory Air Models (SCRAM) website at http://www.epa.gov/ttn/scram.

1.5 Overview of Modeling Protocols and Checklists

Modeling protocols and guidance checklists outline how modeling analyses should be conducted and how a modeling analysis will be presented. It is through such documents that ADEQ is attempting to expedite the permitting process. In a modeling protocol, emission sources should be discussed in sufficient detail, and include the derivation of all source parameters. Those parameters should be derived from the final source configuration, or if not finalized, approximated from the best available information at the time the protocol is developed. Protocols should also address the relevant modeling requirements and recommendations from state/federal regulations and air quality modeling guidelines.

ADEQ recognizes that many air quality specialists have their own preferred formats for protocols. ADEQ does not wish to require applicants to use a specific modeling protocol format. Instead, ADEQ has generated a listing of typical protocol elements as an aid in developing a modeling protocol. This listing does not address all possible components of a protocol. Case-by-case judgments should be used to decide if additional aspects of an analysis should be included in the protocol or if certain elements are not necessary in a given situation. An example list of modeling protocol elements is provided in **Appendix A**.

It is highly recommended that applicants submit a modeling protocol to ADEQ for approval prior to commencing a refined modeling or PSD modeling analysis. A modeling report without a pre-approved modeling protocol will be treated and reviewed as a protocol. Applicants are encouraged to submit a modeling protocol electronically (email is acceptable). Complete hard copies of the protocol will be accepted but must be accompanied with a CD, DVD or other means containing an electronic copy of the submission. In general, the protocol submittal should be sent to the ADEQ's Permits Section where a permit review staff processes the permit application. However, it is appropriate for applicants or their modelers to send modeling protocols directly to modeling staff in the ADEQ's Permits Section. If doing so, a copy must also be sent to the permit review staff since he/she is responsible for the overall review of the permit. Depending on the project, applicants may need to send a protocol copy to federal agencies such as EPA Region 9 and the affected federal land managers. ADEQ will make the determination as to which federal agencies and other entities should also be sent a copy of the protocol, but applicants are free to distribute the protocol more widely.

Applicants should allow a minimum of two (2) weeks for ADEQ to review a modeling protocol. Upon completion of the review, applicants will receive either a written or email notification of acceptance of the modeling approach, or a written or email request for additional information which may contain guidance on any issues needing further clarification. ADEQ will issue a written or email approval of a modeling protocol once agreement is reached.

Applicants should understand that an approved modeling protocol does not necessarily limit the extent of the modeling that will be required. Additional modeling may be required as determined by ADEQ on a case-by-case basis.

In some cases checklists may be required for review but are for the purpose of applicant guidance and expediting the review, and do not serve to indicate a complete application or protocol.

1.6 Overview of Modeling Reports

In most cases, the approved modeling protocol may serve as the foundation of the modeling report. Modeling reports should include a discussion of each relevant modeling protocol element listed in Appendix A. In addition, they should also include several graphic figures which appropriately indicate facility impacts relative to surrounding terrain, residences, schools, etc. Graphics showing building layouts, source locations, and ambient air boundaries are also required.

For the modeling report ADEQ will also require all electronic modeling files including model input files, model output files, model plot files, building downwash files, meteorological data files, etc. The electronic modeling files should utilize the general file formats described in the model user's guides. It is required that modeling files provided to ADEQ should be formatted so that they can be directly processed using EPA's DOS executables from the SCRAM bulletin board (http://www.epa.gov/ttn/scram). The electronic files should not be submitted in a format specific to proprietary modeling software programs which do not precisely follow the formats described in the user's manual for models such as AERMOD.

For instructions regarding how and where to submit modeling reports, please refer to the instructions on modeling protocols as discussed in Section 1.5.

2 LEVELS OF MODELING ANALYSIS SOPHISTICATION

Two levels of modeling sophistication (screening and refined modeling) may be used to demonstrate compliance with National Ambient Air Quality Standards (NAAQS).

Modeling analyses vary widely in complexity based on the type of source being modeled. A simple modeling analysis might include the consideration of a single smoke stack that could be considered using a screening model (Discussed in Section 2.1). A complex analysis can include several hundred smoke stacks, roads, fugitive sources, and regional sources. A complex analysis would require a refined model to simulate ambient impacts.

2.1 Screening Modeling

The first level of sophistication involves the use of screening procedures or models. Screening modeling is typically the quickest and easiest way to show compliance with air quality standards and guidelines. Screening models use simple algorithms and conservative techniques to determine whether the proposed source will cause or contribute to the exceedance of an air quality standard or guideline.

Screening models are usually designed to evaluate a single source or sources that can be co-located (see Section 3.3.9). When screening models are utilized for multiple sources, it is necessary to model each source separately and then add maximum impacts from each model run to determine an overall impact value. Results utilizing this methodology are expected to be conservative since the maximum impacts from each modeled source (regardless of different impact locations at different times) are summed together for a total impact value from a facility.

The current recommended model for screening sources in simple and complex terrain is the most recent version of EPA's AERSCREEN model. The AERSCREEN model can be downloaded from EPA's Support Center for Regulatory Air Models (SCRAM) website at http://www.epa.gov/ttn/scram. The AERSCREEN model has replaced the previous SCREEN3 model as the recommended screening model (U.S. EPA, 2011a). **Analyses performed with SCREEN3 will no longer be accepted by ADEQ for permitting purposes.**

AERSCREEN, a screening-level air quality model based on AERMOD, is a steady-state, single-source, Gaussian dispersion model to provide an easy-to-use method of obtaining pollutant concentration estimates (U.S. EPA, 2011b). The AERSCREEN model consists of two main components: the MAKEMET program; and the AERSCREEN command-prompt interface program. The MAKEMET program generates application-specific worst-case meteorology using representative ambient air temperatures, minimum wind speed, and site-specific surface characteristics (albedo, Bowen ratio, and surface roughness). The AERSCREEN program interfaces with AERMAP (terrain processor in AERMOD) and BPIPPRM (building downwash tool in AERMOD) to process terrain and building information respectively, and interfaces with the AERMOD model utilizing the SCREEN option to perform the modeling runs. AERSCREEN interfaces with version 09292 and later versions of AERMOD and will not work with earlier versions of AERMOD. The AERSCREEN program generates estimates of "worst-case" 1-hour concentrations for a single source, and also automatically provides impacts for other averaging periods using scaling ratios. The averaging period ratios currently implemented in AERSCREEN are shown in Table 1.

Table 1 AERSCREEN Scaling Factors

Model Output	Desired Averaging Period				
	1-hour	3-hour	8-hour	24-hour	Annual
1-hour	1.0	1.0	0.9	0.6	0.1

The screening analysis with AERSCREEN should be consistent with the guidance contained in EPA's *Guideline on Air Quality Models* and appropriate screening modeling documents such as the *Screening Procedures for Estimating the Air Quality Impact of Stationary Sources* (U.S. EPA, 1992a).

If a screening analysis indicates that the predicted concentrations from a source exceed a standard, guideline or a *de minimis* amount the applicant should work with the ADEQ to determine if either refined modeling or reasonable changes to the facility would be appropriate to limit ambient impacts. The reasonable changes may include reducing emissions, reducing hours of operation, increasing stack heights, increasing stack airflows, etc, as long as the changes do not fall within the EPA's definitions of "prohibited dispersion techniques" at 40 CFR 51.100 (hh)(1)(i)-(iii). If modifications to the facility are not feasible or are unreasonable, it is necessary to refine the modeling results using a higher level of modeling sophistication. In this case, a refined modeling analysis is warranted.

Additionally, there are a variety of screening models and screening procedures for different purposes. For example, VISCREEN can be used for evaluating plume coloration and contrast in a Class I area and is typically required for major sources located within 50 km of a Class I area. VISCREEN can be used in two levels referred to as Level I and Level II. Level I utilizes the default worst-case meteorological conditions and particle characteristics. Level II is a refined screening analysis and includes a frequency analysis of local hourly meteorological data to produce a more representative meteorological situation. The particle size and density can also be modified to better represent the site-specific particle characteristics. For detailed instructions on using this model, please refer to the *Workbook for Plume Visual Impact Screening and Analysis* (Revised) (U.S. EPA, 1992b). If a Level II analysis indicates that the threshold value of plume coloration and/or contrast is exceeded, the applicant may be required to conduct the refined modeling for plume visibility using PLUVUE II.

2.2 Refined Modeling

ADEQ may determine that refined modeling is necessary if the results of the screening or refined screening analysis indicate that the predicted concentrations from a source exceed a standard, guideline, or a *de minimis* amount. Typically, it is the applicant's responsibility to perform refined modeling. However, ADEQ may perform this type of modeling under certain circumstances, such as for small businesses that cannot afford the costs associated with refined modeling or for other reasons. ADEQ will charge for these services through applicable permit fees. Before a refined modeling analysis is performed, it is highly recommended that the applicant submit a written modeling protocol that describes the methodologies to be utilized in the modeling analysis and obtain written ADEQ approval before proceeding.

AERMOD

Refined modeling requires much more detailed inputs and complex models to calculate ambient impacts than screening modeling. The primary model used for the refined modeling of industrial sources is the most recent regulatory version of EPA's AERMOD model.

The AERMOD modeling system has replaced Industrial Source Complex 3 (ISC3) as the preferred recommended model for most regulatory modeling applications, as announced in Appendix W of 40 CFR Part 51 (U.S.EPA, 2005). Currently, the AERMOD model can be downloaded from EPA's Support Center for Regulatory Air Models (SCRAM) website at http://www.epa.gov/ttn/scram

AERMOD is a steady-state, multiple-source dispersion model that uses Gaussian or Non-Gaussian treatment depending on atmospheric conditions (Gaussian for stable conditions, non-Gaussian for unstable conditions). AERMOD is the EPA-preferred refined model for estimating impacts at receptors located in simple terrain and complex terrain (within 50 km of a source) due to emissions from industrial sources. AERMOD can predict ambient concentrations using onsite, representative, or worst-case meteorological data sets. AERMOD is capable of calculating downwind ground-level concentrations due to point, area, and volume sources and can accommodate a large number of sources and receptors. AERMOD can also handle line sources by simulating them as a series of area or volume sources. Starting with AERMOD version 12345, a new LINE source type has been included that allows users to specify line-type sources, as an alternative to the current area source type for rectangular sources. (Depending on the line source type that is being modeled, users may wish to model line sources as a series of volume sources, if appropriate.) AERMOD incorporates algorithms for the simulation of aerodynamic downwash induced by buildings. AERMOD handles flat terrain and complex terrain using a consistent approach, which is different from ISC3's critical dividing streamline approach. As a result, users do not need to specify flat terrain (receptor elevation is less than final plume rise) or complex terrain (receptor elevation is higher than final plume rise). As long as the terrain elevations are appropriately assigned for sources and receptors, AERMOD will calculate concentrations for flat and complex terrain intrinsically. AERMOD does not handle atmospheric chemistry processes, except in a few circumstances (for example, the SO_2 half-life for urban sources as discussed in Section 3.7 and the NO_2 chemistry as discussed in Section 7.1). Modeling involving pollutant transformations (i.e. ozone, sulfates, etc.) is not generally required for new or modified sources and is not addressed in this guidance document.

In general, AERMOD should be run in the regulatory default mode. The applicant may use the following non-default or beta options without justification:

- Plume Volume Molar Ratio Method (PVMRM) or Ozone Limiting Method (OLM) for NO_2 modeling (see Section 7.1.3; note that the applicant does need to justify which method is more suitable);
- Beta options for raincap stacks (POINTCAP) and horizontal stacks (POINTHOR) (see Section 3.3.8).

For using other non-default options or beta options, the applicant should provide sufficient justification and get approval from ADEQ. For example, the latest version of AERMOD (version 12345) has incorporated two new beta (non-Default) options, LowWind1 and LowWind2, to address potential concerns regarding model performance under low wind speed conditions. If the applicant believes that using such beta options is more appropriate for their case, it is the applicant's responsibility to demonstrate this and get approval by ADEQ. Otherwise, these beta options should not be used.

CALPUFF

The CALPUFF model is typically used to assess impacts at Class I areas. CALPUFF incorporates more sophisticated physics and chemistry and requires more extensive data input than AERMOD. CALPUFF is a multi-layer, multi-species non-steady-state puff dispersion model that simulates the effects of time- and space-varying meteorological conditions on pollution transport, transformation and removal. It includes algorithms for sub-grid scale effects (such as terrain impingement), as well as longer range effects (such as pollutant removal due to wet scavenging and dry deposition, chemical transformation, and visibility effects of particulate matter concentrations). The *User's Guide for the CALPUFF Dispersion Model* (Earth Tech, 2000) provides more information on the CALPUFF model. The files associated with the CALPUFF system, e.g., executables/source code, preprocessors, associated utilities, test cases, selected meteorological data sets and documentation can be found on TRC's website at http://www.src.com/calpuff/calpuff1.htm

The EPA regulatory approved version of CALPUFF should always be used for regulatory applications unless otherwise approved by ADEQ and EPA. Currently, CALPUFF-Version 5.8 is the version of the modeling system officially approved by EPA.

While CALPUFF can be applied on scales of tens to hundreds of kilometers, it is currently used for long range transport assessments (greater than 50 km but less than 300 km from the emission source). CALPUFF is not the EPA-preferred model for near-field (less than 50 kilometers) applications, but may be considered as an alternative model on a case-by-case basis for near-field applications involving "complex winds" (U.S. EPA, 2008a). Any use of CALPUFF in the near-field must be thoroughly justified and approved by ADEQ and EPA. The basic requirements for justifying use of CALPUFF for near-field regulatory applications consist of three main components:

- Treatment of complex winds is critical to estimating design concentrations;
- The preferred model (AERMOD) is not appropriate or less appropriate than CALPUFF; and
- Five criteria listed in paragraph 3.2.2(e) of the Guideline for use of CALPUFF as an alternative model are adequately addressed.

3 MODELING ANALYSIS FEATURES

This section provides an overview of the major components of a permit modeling analysis. Model user's guides may also be useful in providing the applicant detailed information regarding features of a modeling analysis. When in doubt, modeling questions should be presented to ADEQ for assistance.

3.1 Modeling Worst-Case Scenarios

For each applicable pollutant and each applicable averaging time, a modeling analysis must consider worst-case scenarios based on evaluation of the following:

- Different operating modes of equipment (e.g. simple cycle and combined cycle for turbines),
- Various emission rates (normal steady-state operations, start-up and shutdown operations, emissions at various loads, spikes in short-term emissions, alternative fuels, etc.), and
- The effect of various operational loads on emission rates and dispersion characteristics, such as stack exit velocity.

Based on the evaluation, a worst-case scenario for each pollutant and averaging time can be selected as the basis for the modeling run.

3.1.1 Emissions Profiles

The maximum short-term emission rates for each source should be used to demonstrate compliance with all short-term averaging standards and guidelines. If equipment is to be operated under different conditions, such as operating hours, load factor or fuel type, each emission scenario should be evaluated and the maximum short-term emission rate should be used. The emission profile should clearly describe the underlying factors from which the emissions are derived. For example, for dual-fuel combustion sources, the fuel-type that would generate the highest emissions should be modeled. Another example is for gas turbines, which have different emissions and source parameters, such as exit velocity and exit temperature under different loads. This is further explained in **Section 3.1.2**.

Some sources may have higher-than-normal emissions triggered by certain events. For example, high short-term emissions may result from startup/shutdown operations or bypasses of control equipment. For compliance demonstrations with the 1-hour NO_2 or SO_2 NAAQS, special consideration should be given to determine whether such emissions should be included in the modeling analysis or not. Because of the probabilistic nature of the two standards, EPA recommends that the most appropriate data to use for compliance demonstrations for the 1-hour NO_2 and SO_2 standards are those based on emissions scenarios that are continuous enough or frequent enough to contribute significantly to the annual distribution of maximum daily 1-hour concentrations. Therefore, ADEQ may allow an exemption from 1-hour NO_2 and SO_2 modeling if these events are infrequent enough so that the emissions caused by these events will not contribute significantly to the annual distribution of maximum daily 1-hour concentrations (see Section 7.1.6). As the exemption determination is on a case-by-case basis, the applicant should provide ADEQ detailed information about these events such as frequency and duration (see Section 7.1.6). Based on Appendix W Section 8.1.2.a - footnote a (U.S. EPA, 2005), modeling emissions due to malfunction is not required unless the emissions are the result of poor maintenance, careless operation, or other preventable conditions.

For compliance demonstrations with the 24-hour or annual NAAQS, emission rates modeled should incorporate a suitable number of these high-emission periods combined with normal equipment operations. For example, power generation facilities are typically permitted for a certain number of startup/shutdown events. Therefore, calculations for 24-hour average emissions or annual emissions for a power generation facility must consider the emissions from startup/shutdown events combined with emissions from steady-state operations.

It is important that the applicant provide emissions information for all averaging times to be considered in the modeling analysis. Potential short-term emissions "spikes" from highly fluctuating short-term emissions sources (such as some types of kilns) also need to be characterized and considered in the modeling analysis.

Emissions from equipment used during emergency conditions, such as fire pumps to provide water in responding to fires and emergency generators to provide power during the unexpected interruption of electrical service from the utility, are generally not required in compliance modeling. However, emissions from routine testing or maintenance on such emergency equipment should be included, unless the sources fall within the definition of "intermittent sources" that can be exempted from 1-hour modeling for compliance demonstration (see Section 7.1.6).

3.1.2 Load Analyses

A load analysis is also required for equipment that may operate under a variety of conditions that could affect emission rates and dispersion characteristics. A load analysis is a preliminary modeling exercise in which combinations of parameters (e.g. ambient temperature, sources loads, relative humidity, etc.) are analyzed to determine which combination leads to the highest modeled impact. For example, turbines should be evaluated at varying loads and temperatures to determine the worst-case modeled impacts. Furthermore, cold temperature conditions at the site also should be considered. The GAQM provides further guidance on conducting a load analysis and recommends that at a minimum, load analyses should be conducted at 100%, 75% and 50% capacity. However, each applicant can choose the load factors that are most representative of their own operating conditions. The stack parameters of various load levels that result in the highest impact should be used in compliance demonstration.

3.1.3 Emission Caps

Some facilities may wish to accept facility-wide emissions caps for a particular pollutant. However, emissions of these pollutants may exhaust into the atmosphere through various stacks. Different stacks with different dispersion parameters may result in significantly different ambient impacts, especially in complex terrain. Many operational possibilities exist under a proposed facility-wide cap. To adequately evaluate the ambient impacts of variable emissions of pollutants with facility-wide caps, the applicant needs to consider several operational scenarios.

For example, assume that two stacks, Stack A and Stack B, have very different dispersion differences (i.e. different stack heights, airflows, and exhaust diameters). Assume that Stack A typically emits 25% of the emissions and Stack B emits 75% of the emissions from the throughput in a single production unit. Assume that it is possible to configure the production unit so that Stack A is bypassed and all of the emissions exhaust through Stack B (and vice versa). Under this scenario, the applicant should consider the following modeling scenarios in addition to the aforementioned typical operating scenario: (a) 100% of emissions through Stack A only, (b) 100% of emissions through Stack B only, and (c) 50% of emissions through Stack A and 50% of emissions through Stack B. In other words, the applicant needs to determine and separately present worst-case modeled impacts resulting from various operating scenarios, since a facility-wide cap would allow for such operational flexibility. These analyses are intended to demonstrate that the health and welfare of the public will be protected from all potential operating scenarios of a proposed project.

3.2 Modeling Emissions Inventory

A modeling emissions inventory may consist of the emission points of the sources to be permitted, as well as other applicable onsite and offsite sources. An organized emissions inventory provides a crucial link between the emissions used to determine source applicability and the emissions used directly in the modeling analysis. Applicants are required to calculate emissions for proposed projects and compare these values to trigger thresholds for PSD applicability, Maximum Achievable Control Technology (MACT) applicability, etc. Typically, these emissions calculations are presented as annual emissions with units of ton/yr. On the other hand, modeling analyses typically utilize emission rates with units of lb/hr or g/sec.

The averaging periods over which ambient standards and guidelines apply vary depending upon pollutant type. For example, emissions over 1-hour and 8-hour periods would be needed to compare the ambient impact of carbon monoxide emissions with the 1-hour and 8-hour standards for carbon monoxide. For sulfur dioxide, short-term ambient standards are in terms of 1-hour and 3-hour averaging periods. For nitrogen dioxide, the short-term ambient standard is in terms of a 1-hour averaging period. Emission inventories should be tabulated for all different averaging periods applicable to pollutants emitted from a facility.

To expedite ADEQ's review of the permit application and associated modeling analyses, it is suggested that the applicant calculates lb/hr, ton/yr, and g/s emission rates for all averaging times in the same (or similar) tables. These emissions tables should also include operational limits (hr/day, hr/yr) and production material throughputs and/or unit ratings for each emission source. Emissions units are typically considered on a production unit basis while modeling requires the consideration of exhaust points. It is possible to have several production units that exhaust to a common exhaust point. Therefore, emissions should be presented in the permit application so that it is possible to determine source applicability while also clearly indicating the calculations utilized to determine modeled emission rates for each exhaust point at the facility.

3.3 Types of Sources

Regulatory modeling should reflect the actual characteristics of the proposed emission sources. Several different source types used to characterize emissions releases are described in this section.

3.3.1 Point Sources

The point source is the most common type of source that is modeled in permit modeling analyses. Emissions from point sources are released to the atmosphere through well-defined stacks, chimneys, or vents. The following stack parameters are needed to model point sources:

- Emission rate in g/s,
- Stack inside diameter in meters,
- Stack height above grade in meters,
- Stack gas exit velocity in m/s,
- Stack gas exit temperature in degrees K.

Since the AERMOD model uses direction-specific building dimensions for all sources subject to building downwash, there are no building parameters entered on the source parameters (SRCPARAM) card. Building dimensions are entered on the building's dimensions card. If "0.0" is input for the stack exit temperature, AERMOD adjusts the hourly exit temperature to be equal to the ambient temperature. This allows the user to model a plume released at ambient temperature. If a negative constant is input for the exit temperature, AERMOD will adjust the exit temperature to be equal to the ambient temperature plus the absolute value of that constant. AERMOD currently does not have the capability to model plumes with an exit temperature below the ambient temperature.

3.3.2 Volume Sources

Volume sources are used to model releases from a variety of industrial sources such as building roof monitors, multiple vents, conveyor belts, roads, drop points from loaders, and material storage piles. Moreover, line sources (e.g. road emission sources as described in Sec. 3.3.5) have long been recommended to be modeled as a series of volume sources. The following parameters are needed to model volume sources:

- Emission rate in g/s,
- Source release height (center of volume) above ground (h_e) in meters,
- Initial lateral dimension of the volume (σ_{yo}) in meters,
- Initial vertical dimension of the volume (σ_{zo}) in meters.

The release height of a volume source is the height of the center of the volume source above grade. Determination of the initial lateral and vertical dimensions (referred to as initial sigmas) are based on the geometry and location of the source. The actual physical dimensions of the release (i.e. actual height, actual width, and actual length) are adjusted to generate the initial lateral and vertical dispersion parameters for use in the model. The base of a volume source must be a square. If the source cannot be characterized as square, then the source should be characterized as a series of adjacent volume sources. For relatively uniform sources, determine the "equivalent square" by taking the square root of the projected area of the volume.

Table 2 provides a summary of the suggested procedures for estimating the initial lateral dimensions and initial vertical dimensions for volume and line sources as presented in the *USER'S GUIDE FOR THE AMS/EPA REGULATORY MODEL – AERMOD* (U.S. EPA 2004a).

Table 2 Suggested Procedures for Estimating Volume Source Parameters

Type of Source	Procedure for Obtaining Initial Dimension
Initial Lateral Dimensions (σ_{yo})	
Single Volume Source	σ_{yo} = length of side divided by 4.3
Line Source Represented by Adjacent Volume Sources	σ_{yo} = length of side divided by 2.15
Line Source Represented by Separated Volume Sources	σ_{yo} = center to center distance divided by 2.15
Initial Vertical Dimensions (σ_{zo})	

Surface-Based Source (h_e ~ 0)	σ_{zo} = vertical dimension of source divided by 2.15
Elevated Source (h_e > 0) on or Adjacent to a Building	σ_{zo} = building height divided by 2.15
Elevated Source (h_e > 0) not on or Adjacent to a Building	σ_{zo} = vertical dimension of source divided by 4.3

3.3.3 Area Sources

Area source algorithms are used to model low level or ground level releases with no plume rise such as storage piles, slag dumps, and lagoons. The AERMOD model uses a numerical integration approach for modeling impacts from area sources. AERMOD includes three options for specifying the shape of an area source:

- AREA – for rectangular areas that may also have a rotation angle specified to a north-south orientation. The parameters needed are: 1) area emission rate in g/(s-m^2), 2) source release height above ground in meters, 3) length of X side of area in meters, 4) length of Y side of area in meters, and 5) optional inputs of orientation angle in degrees and initial vertical dimension of the area source plume in meters.

- AREAPOLY – area of an irregularly shaped polygon of up to 20 sides. The necessary input parameters are: 1) area emission rate in g/(s-m^2), 2) source release height above ground in meters, 3) number of vertices, 4) coordinates of each vertex and 5) an optional initial vertical dimension of the plume in meters.

- AREACIRC – for circular shaped area sources The necessary input parameters are 1) area emission rate in g/(s-m^2), 2) source release height above ground in meters, 3) radius of circular area in meters and number of vertices (AERMOD will automatically approximate the area of the circle as the area of a polygon with 20 vertices if this is omitted), and 4) an optional initial vertical dimension of the plume in meters.

The performance stability of the numerical integration algorithm for area sources may strongly depend on the aspect ratio (i.e., length/width). An aspect ratio upper limit of 10:1 was initially used as a criterion for issuing a non-fatal warning message in the earliest versions of AERMOD. Starting with AERMOD Version 09292, EPA has modified the criterion from an aspect ratio of 10:1 to an aspect ratio of 100:1, stating that a ratio of 10:1 is probably too strict and may unnecessarily lead to a large number of warning messages in some cases. However, it should be addressed that the upper limit of aspect ratio for stable performance of the numerical integration algorithm for area sources has not been fully tested and documented. Therefore, the applicant should always check to ensure that the aspect ratio used is appropriate.

It should also be noted that the emission rate for the area source is an emission rate per unit area, which is different than the point and volume source emission rates, which are total emissions for the source.

3.3.4 Line Sources

Starting with AERMOD version 12345, a new LINE source type has been included that allows users to specify line-type sources based on a start-point and end-point of the line and the width of the line, as an alternative to the current AREA source type for rectangular sources. The LINE source type utilizes the same routines as the AREA source type, and will give identical results for equivalent source inputs. The LINE source type also includes an optional initial sigma-z parameter to account for initial dilution of the emissions. As with the AREA source type, the LINE source type does not include the horizontal meander component in AERMOD.

Since the LINE source type includes both start and endpoints, an issue has been raised regarding inclusion of LINE source type in AERMAP, the terrain processor for AERMOD (i.e., what reference point to use in AERMAP). Until this issue is clarified, the applicant should avoid using the LINE source type.

3.3.5 Road Emission Sources

ADEQ requires modeling of fugitive road dust for both short-term and annual averaging periods. Road emissions can be represented as a series of volume sources. ADEQ follows the volume source technique recommended by EPA's Haul Road Workgroup for modeling haul road emissions (Haul Road Workgroup, 2011). The permit modeling analysis must include road emissions if they will be generated in association with transport, storage, or transfer of materials (raw, intermediate, and waste), including sand, gravel, caliche, or other road-based aggregates.

To represent road emissions by volume sources, follow the eight steps described in the following paragraphs.

Volume Step 1: Determine the adjusted width of the road. For single-lane roadways, the adjusted width is the vehicle width plus 6 meters. For two-lane roadways, the adjusted width is the actual width of the road plus 6 meters. The additional width represents turbulence caused by the vehicle as it moves along the road. This width will represent a side of the base of the volume.

Volume Step 2: Determine the number of volume sources, N. Divide the length of the road by the adjusted width. The result is the maximum number of volume sources that could be used to represent the road.

Volume Step 3: Determine the height of the volume. The height will be equal to 1.7 times the height of the vehicle generating the emissions.

Volume Step 4: Determine the initial horizontal sigma ($\boldsymbol{\sigma_{yo}}$) for each volume.

- If the road is represented by a single volume source, divide the adjusted width by 4.3.
- If the road is represented by adjacent volume sources, divide the adjusted width by 2.15.
- If the road is represented by alternating volume sources, divide twice the adjusted width – measured from the center point of the first volume to the center point of the next represented volume – by 2.15. Start with the volume source nearest the process area boundary. This representation is often used for long roads.

Volume Step 5: Determine the initial vertical sigma ($\boldsymbol{\sigma_{zo}}$). Divide the height of the volume determined in Step 3 by 2.15.

Volume Step 6: Determine the release height. Divide the height of the volume by two. This point is the center of the volume.

Volume Step 7: Determine the emission rate for each volume used to calculate the initial horizontal sigma in Step 4. Divide the total emission rate equally among the individual volume sources used to represent the road, unless there is a known spatial variation in emissions.

Volume Step 8: Determine the UTM coordinate (See Section 3.5) for the release point. The release point location is in the center of the projected area of the volume. This location must be at least one meter from the nearest receptor.

For cases where volume sources cannot be used due to ambient air receptors being located in the volume source exclusion zone, road emissions can be modeled as area sources with:

- Length – length of roadway segment (Aspect ratio in AERMOD extended to 100:1 before warning);
- Top of plume, release height, plume width, and Sigma Z set to values listed above for volume sources;
- Emission rate in grams/second/m^2

3.3.6 Flares

Flares are typically modeled in either standard mode or event mode. In standard mode, the pilot gas, purged gas or assist gas is burning at relatively low intensity - a small flame is usually present. In event mode, the flare is burning during temporary startup, shutdown, maintenance of a process or control unit - a large flame is present, with intense heat release and buoyancy.

Flares are typically modeled similar to point sources. However, the heat release from the flare is utilized to calculate plume rise. For screening purposes, the flare options in the AERSCREEN model are acceptable. For refined modeling, it is necessary to compute equivalent emission parameters (i.e. adjusted values of temperature, stack height, and diameter) to account for the buoyancy of the plume since the flare option is not available in the AERMOD model.

Several methods for computing equivalent emission parameters appear in the literature. However, it does not seem that any one method is universally accepted. The technique to calculate the buoyancy flux for flares generally follows the technique described in the *SCREEN3 User's Guide* (U.S. EPA, 1995), *Ohio EPA's Air Dispersion Modeling Guidance* (Ohio EPA, 2003) *and Alaska Modeling Review Procedures Manual* (ADEC, 2006). In general, use the following parameters to model a "typical" flare:

- Effective stack exit velocity = 20 meters per second
- Effective stack exit temperature = 1273 Kelvin
- Adjust the stack height and inside diameter to account for the flame height and the buoyancy of the plume by using the following equations:

$$H_{equiv} = H_{actual} + 0.944(Q_c)^{0.478}$$

$$D_{equiv} = 0.1755(Q_c)^{0.5}$$

where, H_{equiv} = equivalent release height of the flare, in meters
H_{actual} =actual height of the flare stack above grade, in meters
Q_c = heat release of the flare, in MMBTU/hr
D_{equiv} = equivalent diameter of the flare, in meters

This method pertains to the "typical" flare. The method will be relatively accurate depending on flare parameters such as heat content, molecular weight of the fuel, and velocity of the uncombusted fuel/air mixture. Hence, this method may not be suitable for all conceivable situations. In this case, the applicant may submit a properly documented method for consideration by ADEQ.

Flare emissions from different modes should be evaluated to determine the worst-case impact. For a flare "event", the emissions associated with the startup, shutdown or maintenance should be considered. Modeling emissions due to malfunction is not required unless the emissions are the result of poor maintenance, careless operation, or other preventable conditions (U.S. EPA, 2005). Similar to a load analysis, the emission rate and the "stack parameters" that leads to highest ground level impact should be used in modeling short-term impact. For annual impact analysis, a representative combination of different operation modes should be developed to determine an average annual emission rate. However, it is not appropriate to average "stack parameters", such as exit velocity and effective diameter. The parameters that would lead to higher impact should be used in modeling.

3.3.7 Open Pit Sources

Open pit algorithms are used to model particulate emissions from open pits, such as surface copper mines and rock quarries. These algorithms simulate emissions that initially disperse in three dimensions with little or no plume rise. Open pit algorithms are available in AERMOD, which essentially adopts the ISC3 open pit algorithm. In the AERMOD model, the open pit algorithm uses an effective area for modeling pit emissions based on meteorological conditions. The algorithm then utilizes the numerical integration area source algorithm to model the impact of the emissions from the effective area sources. The following parameters are needed to model open pit sources: open pit emission rate (emission rate per unit area), average release height above the base of the pit, the initial length and width of the pit, and the volume of the pit. An optional input is "ANGLE," which specifies the orientation angle for the rectangular open pit in degrees from North, measured positive in clockwise direction (*Addendum User's Guide for the AMS/EPA Regulatory Model – AERMOD*, U.S.EPA, 2004a).

3.3.8 Pseudo Point / Non-Standard Point Source

Pseudo point sources may be used to represent vent emissions, such as those from storage tanks. Typically such releases occur at ambient temperature and with little driving force. Consequently, these releases are characterized with minimal momentum and buoyancy. The configuration of these sources must reflect these characteristics by adjusting the stack parameters.

The Texas Commission on Environmental Quality (TCEQ) provides a method to model pseudo point sources (TCEQ, 1999). If it is necessary to model emissions from fugitive sources and if a pseudo-point characterization is appropriate, then the applicant can use the following modeling parameters:

- Stack exit velocity = 0.001 meters per second
- Stack exit diameter = 0.001 meter
- Stack exit temperature = 0 Kelvin (causes the AERMOD model to use the ambient temperature as the exit temperature)
- Actual release height

It is suggested that the applicant provide ADEQ with details regarding the pseudo point sources for review prior to modeling.

Non-standard point sources include non-vertical stacks or vertical stacks with obstructed emissions (such as a raincap). Currently, AERMOD includes two beta options for raincap stacks (POINTCAP) and horizontal stacks (POINTHOR). ADEQ will accept the use of these beta options until an EPA approved alternative method for modeling non-vertical and/or obstructed emissions is accepted. To use these beta options, the user should input actual stack parameters, including exit velocity, exit temperature and stack diameter. The source location should be given in the same way as for standard point sources. AERMOD will apply internal adjustments to the stack parameters for plume rise and stack-tip downwash. For horizontal releases, AERMOD assumes that the release is oriented with the wind direction. For PRIME-downwash sources, the user-specified exit velocity for horizontal releases is treated initially as horizontal momentum in the downwind direction. For detailed guidance, please refer to the *AERMOD Implementation Guide* Section 6.1 (U.S. EPA, 2009a).

3.3.9 Emission Point Collocation

Regulatory modeling should reflect the actual characteristics of the proposed or existing emissions points at a facility. Therefore, emission points should not be co-located except in well-justified situations. For example, collocation may be appropriate when the number of emission points at a large facility exceeds the capability of the model. It is not acceptable to co-locate emission points merely for convenience or to reduce model run time. Collocating emission points may be appropriate if individual emission points:

- Emit the same pollutant(s),
- Have the same source release parameters, and
- Are located within 100-meters of each other.

For very large emission sources such as power plants and copper smelters, ADEQ does not allow co-location of individual emission points since slight movements in the location of large emission points can significantly impact modeling results for NAAQS, PSD increment, and visibility analyses.

It is suggested that the applicant provides ADEQ details regarding the possible co-location of emission points for review prior to modeling.

3.4 Ambient Air Boundary

The ambient air boundary must be determined before an ambient air assessment can be completed. Permit applicants are required to demonstrate modeled compliance with NAAQS or PSD increments at receptors spaced along and outside the ambient air boundary (Section 3.6). The recent revised NAAQS for NO_2, SO_2, PM_{10} and $PM_{2.5}$ are significantly more stringent than the previous standards and in conjunction with EPA ambient air policy will provide protection of the public health previously afforded by the process area boundary (PAB) policy. Therefore, ADEQ has determined that the EPA's ambient air policy will be incorporated into this guidance for modeling purposes.

40 CRF Part 50.1(e) defines ambient air as, "…that portion of the atmosphere, external to buildings, to which the general public has access." A letter dated December 19, 1980, from EPA's Administrator Douglas Costle to Senator Jennings Randolph, has stated that "the exemption from ambient air is available only for the atmosphere over land owned or controlled by the source and to which public access is precluded by a fence or other physical barriers". The Regional Meteorologists' memorandum has further stated that

"…for modeling purposes the air everywhere outside of contiguous plant property to which public access is precluded by a fence or other effective physical barrier should be considered in locating receptors" (U.S. EPA,1985). Based on these definitions and guidance, ADEQ has developed the following guidance to be used when determining the ambient air boundary for a facility.

3.4.1 Definition of General Public

According to EPA, the general public includes "anyone who is not employed by or under control of the facility, but, more specifically, persons who do not require the facility's permission to be on the property" (U.S. EPA, 2007). The general public may not include mail carriers, equipment and product suppliers, maintenance and repair persons, as well as persons who are permitted to enter restricted land for the business benefit of the person who has the power to control access to the land. Therefore, ADEQ does not consider individuals who in some way interact with or participate in a source's activities to be part of the general public. Such individuals would include, for example, the owner/operator and its employees, contractors and their employees, vendors and support businesses and their employees, and government agencies and services and their employees.

EPA has further clarified that the general public should include (U.S. EPA, 2007):

- Customers of a business to which access is typically not restricted during business hours. For example, the customer of a restaurant or other retail business is a member of the general public even if the proprietor restricts public access during non-business hours by locking the entrance to the property.
- Persons who are frequently permitted to enter restricted-access land for a purpose that does not ordinarily benefit the "business." For example, EPA has treated athletic facilities within the restricted fence line of a source as ambient air when persons unconnected to the business were regularly granted access for sporting events (which do not necessarily benefit a business).

3.4.2 Public Access

If general public access is effectively precluded by a fence or other physical barriers, the facility is assumed to be controlled and public access effectively precluded, and the ambient air boundary can be set at where the fence line or other physical barriers are located. However, a fence or other physical barriers that are not sufficient to preclude public access should not be used for determining the ambient air boundary. For example, EPA has indicated that a three-strand barb-wire fence may not be adequate to keep the general public off a farm land (U.S. EPA, 2000a).

In addition to fences or other human-made barriers, natural physical barriers may be used as a portion of the ambient air boundary. For example, EPA has indicated that a riverbank can form a natural barrier such that fencing is not necessary (U.S. EPA, 1987a). Such natural barriers should, however, be clearly posted and regularly patrolled by plant security. It should be addressed that, rugged terrain or a water body should not be automatically considered as an effective natural barrier unless the applicant adequately demonstrates and documents that public access can be effectively precluded.

Any public roads will be considered as ambient air. Any streams or rivers transecting a property will be considered as ambient air unless the applicant adequately demonstrates and documents that public access can be legally precluded.

3.4.3 Property without an Effective Fence or Other Physical Barriers

If the facility does not have a fence or other physical barriers to preclude general public access effectively, then ADEQ will accept the use of the facility's Process Area Boundary (PAB) as the ambient air boundary. The PAB is defined as the process areas within the facility occupied by emission generating activities, the area in the immediate vicinity of those activities and the area between adjacent activities.

If the applicant does not wish to use the PAB as the ambient air boundary, the applicant should conduct a case-by-case analysis demonstrating that the general public's access to areas other than the PAB is effectively prevented. ADEQ recommends applicants discuss their approach to such a case-by-case analysis with department staff before submitting a modeling protocol.

3.4.4 Leased Property

Interpretation of ambient air in situations involving leased land is usually complicated. ADEQ should be consulted regarding any specific case involving leased property as it affects the ambient air boundary determination.

Because determining the ambient air boundary is a somewhat subjective exercise involving input from both the applicant and ADEQ, the applicant should provide ADEQ with a scaled facility plot plan or aerial photo clearly indicating the proposed ambient air boundary prior to performing the modeling analysis. If the applicant submits a modeling protocol to ADEQ, the protocol should include a discussion of the ambient air boundary.

3.5 Modeling Coordinate Systems

Refined modeling should always be performed using Universal Transverse Mercator (UTM) coordinates. Please do not use coordinate systems based on plant coordinates. Always indicate the datum used for the UTM coordinates. There are several horizontal data coordinate systems (NAD27, WGS72, NAD83, and WGS84) that are used to represent locations on the earth's surface. Make sure that all coordinates are generated from a common horizontal datum when representing receptor, building, and source locations.

It is necessary to use UTM coordinates to be consistent with emission point locations provided on permit application forms and other reference materials such as USGS topographic maps. In addition, ADEQ utilizes UTM information to check submitted modeling files against digital GIS mapping products.

3.6 Receptor Networks

Receptors should be placed throughout a modeling domain to determine areas of maximum predicted concentrations. The extent of receptor coverage around a facility is usually handled on a case-by-case basis since source dispersion characteristics, topography, and meteorological conditions differ from source to source. **Table 3** indicates typical receptor spacing suggested by ADEQ for modeling analyses. AERMOD has a maximum allowed number of receptors set at 50,000.

Additional modeling should be conducted in the vicinity of each receptor when a predicted concentration exceeds 90% of an applicable standard or guideline. For example, use a tight grid with receptors spaced at 25 meters to fill in the fine, medium, or coarse receptors that indicate a predicted concentration greater than 90% of an applicable standard or guideline.

The furthest extent and spacing of receptors away from the ambient air boundary should be evaluated on a case-by-case basis. In the modeling protocol, the applicant should provide a justification as to the extent and spacing of receptors. In some circumstances, ADEQ may require a receptor network coverage of 50 km, even if the maximum impact from the proposed project is expected to occur near the project site. One common example of such a circumstance would be a project that would cause a significant public concern.

Table 3 Suggested Receptor Spacing

Type of Receptors	**Suggested Receptor Spacing (meters)**	**Receptor Coverage Area**
Tight	25	Along ambient air boundary (AAB)
Fine	100	From AAB to 1 km
Medium	200 - 500	From 1 km to 5 km away from AAB
Coarse	500 - 1,000	From 5 km to 20 km away from AAB
Very Coarse	1,000-2,500	From 20 km to 50 km away from AAB
Discrete	Not Applicable	Place at areas of concern such as nearby residences, schools, worksites or daycare centers
Non-Attainment Area	Case-by-Case	Discuss with ADEQ prior to modeling
Class I and Class II Wilderness Area	Case-by-Case	Discuss with Federal Land Manager prior to modeling

Given the diverse topography of Arizona, most modeling domains include topography above stack height (i.e. complex terrain). Therefore, ADEQ typically requests that refined modeling be performed with elevations included for each receptor.

Receptor elevations should be derived using AERMAP, the terrain processor of AERMOD. AERMAP produces terrain base elevations for each receptor and source, and hill height for each receptor. Prior to 2009, AERMAP utilized bilinear interpolation of regularly spaced nodes as in the two-dimensional U.S. Geological Survey (USGS) Digital Elevation Model (DEM) files. Beginning with version 09040, AERMAP has been revised to support processing of terrain elevations from the National Elevation Dataset (NED) in GEO-TIFF format. As DEM data will no longer be updated while NED data are being actively supported and checked for quality, NED represents a more up-to-date and improved resource for terrain elevations for use with AERMAP. Therefore, permit applicants are encouraged to use NED data instead of DEM data. AERMAP currently does not support processing of elevation data in both the DEM format and the GeoTIFF format for NED data in the same run.

After April 2013, the USGS National Map Server no longer offers download of NED data in GeoTIFF format, which is the format accepted by AERMAP. The server now only provides NED data in ArcGrid and GridFloat formats. To deal with this issue, applicants may download the GeoTIFF NED data from the website of Multi-Resolution Land Characteristics (MRLC) Consortium Viewer, http://www.mrlc.gov/viewerjs/. Another option is to use GIS tools to convert GridFloat format into GeoTIFF format.

It is critical that the terrain processor derive receptor and source elevations on a consistent coordinate system. For example, DEM files could refer to different horizontal datums. A 7.5 minute DEM file refers to either the NAD27 or NAD83 datum; and a one-degree DEM file refers to either the WGS72 or WGS84 datum. More recent DEM files have the record of the reference horizontal datum in the file header, which is read by AERMAP. AERMAP then converts the coordinates in the DEM file to a horizontal datum specified for the modeling domain. Older DEM files that are absent of such record will be read by AERMAP assuming that 7.5 minute DEM files refer to NAD27 and one-degree DEM files refer to WGS72. The applicant should refer to the *User's Guide for the AERMOD Terrain Preprocessor (AERMAP)* (U.S. EPA, 2004b) and the *User's Guide for the AERMOD Terrain Preprocessor (AERMAP) Addendum* (U.S. EPA, 2004c) for detailed instruction of using the AERMAP program.

3.7 Rural/Urban Classification

It is important to determine whether a source is located in an urban or rural dispersion environment. In general, urban areas cause greater rates of dispersion because of increased turbulent mixing and buoyancy-induced mixing. This mixing is due to the combination of greater surface roughness induced by the presence of many buildings and structures and increased amounts of heat released from concrete and similar building materials. AERMOD has two keyword switches for turning on the urban mode: the URBANOPT keyword on the CO pathway and the URBANSRC keyword on the SO pathway. AERMOD enhances the turbulence for urban nighttime conditions more than what would be expected at adjacent rural locations. AERMOD also uses population estimates as a surrogate to define the magnitude of the differential heating caused by the urban heat island effect. It is worth pointing out that AERMOD incorporates the 4-hour half-life for modeling ambient SO_2 concentrations in urban areas under the regulatory default option.

EPA guidance identifies two procedures to make an urban or rural classification for dispersion modeling: the land-use procedure and the population density procedure. Both procedures require the evaluation of characteristics within a 3-kilometer radius from a facility. Of the two procedures, the land-use procedure is preferred. The land-use procedure specifies that the land-use within a three-kilometer radius of the source should be determined using the typing scheme developed by Auer (1978).

If the sum of land use types I1 (heavy industrial), I2 (light to moderate industrial), C1 (commercial), R2 (compact residential-single family), and R3 (compact residential-multiple family) is greater than or equal to 50% of the area within the circle, then the area should be classified as urban. Otherwise the area should be classified as rural. **Table 4** indicates Auer's land-use categories. Unless the source is located in an area that is distinctly urban or rural, the land use analysis should provide the percentage of each land use type from the Auer scheme and the total percentages for urban versus rural. The latest available United States Geological Survey (USGS) topographic quadrangle maps in the vicinity of the facility should be used in this analysis. In some circumstances, such as in an area undergoing rapid development, county or local planning board maps may need to be used.

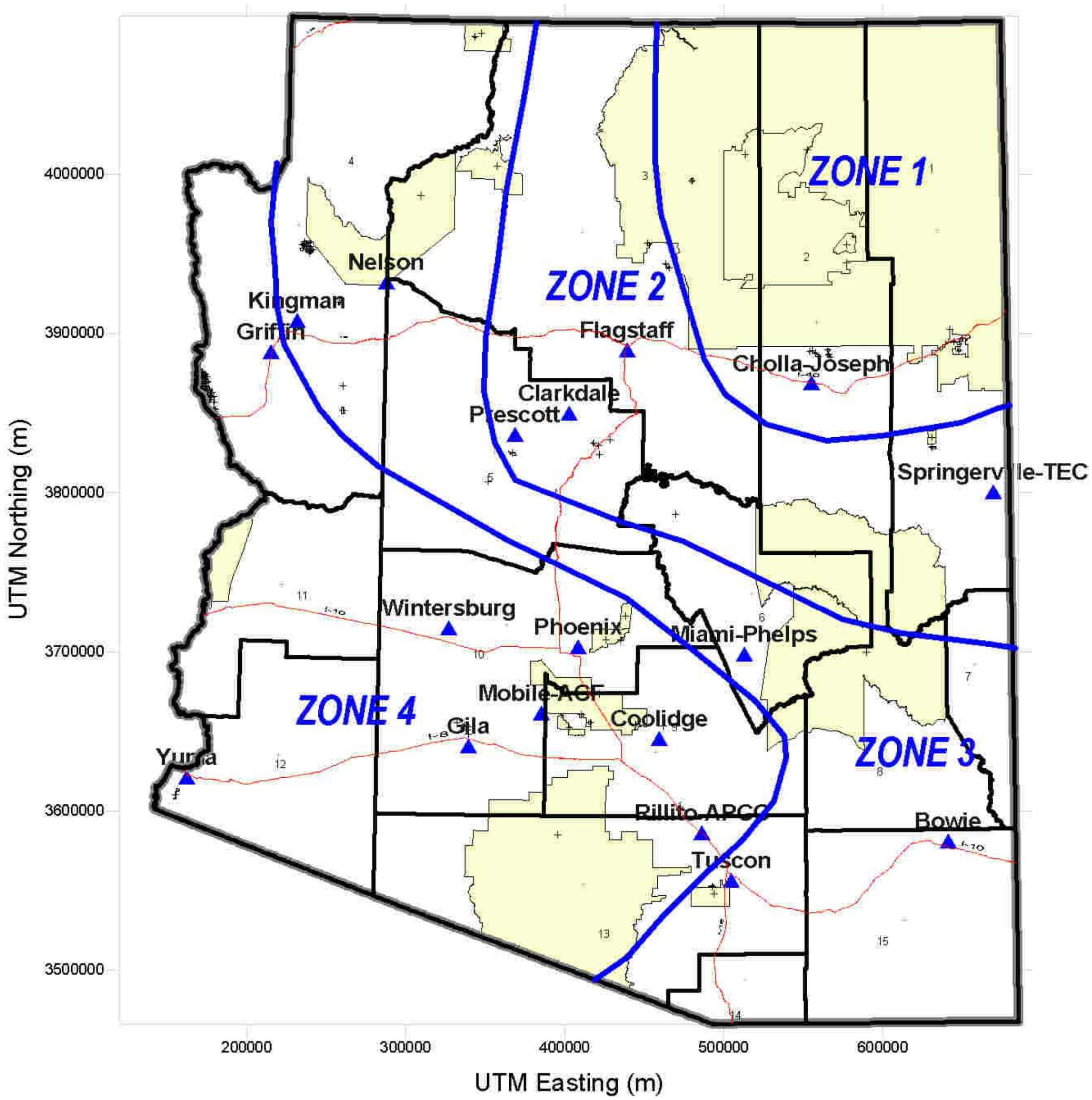
For most applications, the Land Use Procedure described above is sufficient for urban/rural determination. However, cautions must be taken to apply the land use procedure under some special circumstances (U.S. EPA, 2009a). For example, the Auer's land use analysis may result in a rural designation when sources are located within an urban area but located close enough to a large body of water or to other non-urban land use categories. In such cases, the applicant should consider the potential for urban heat island influences across the full modeling domain. While these sources are defined as rural based on the land use procedure, an urban designation may be more appropriate, since the urban heat island is not a localized effect but is more regional in character. Another example is that stacks are located within or adjacent to small to moderate size urban areas but the plume may extend above the urban boundary layer height. In such cases, it is not appropriate to use the urban option in AERMOD since the application of the urban option may artificially limit the plume height. The determination of whether these sources should be modeled separately without the urban option will depend on a comparison of the stack height or effective plume height with the urban boundary layer height.

Table 4 Auer Land -Use Classifications

Auer Type	Description	Urban or Rural?
I1	Heavy Industrial	Urban
I2	Light-Moderate Industrial	Urban
C1	Commercial	Urban
R1	Common Residential (normal easements)	Rural
R2	Compact Residential (single family)	Urban
R3	Compact Residential (multiple family)	Urban
R4	Estate Residential (multi-acre)	Rural
A1	Metropolitan Natural	Rural
A2	Agricultural Rural	Rural
A3	Undeveloped (grasses)	Rural
A4	Undeveloped (heavily wooded)	Rural
A5	Water Surfaces	Rural

3.8 Meteorological Data

ADEQ recognizes that the availability of meteorological data in Arizona is limited. EPA's Support Center for Regulatory Air Models (SCRAM) website http://www.epa.gov/ttn/scram, provides some meteorological data for Arizona which can be used in dispersion models. Additional data from the National Weather Service (NWS) (collected from 20+ sites in AZ) can be obtained from the National Climatic Data Center (NCDC) website at http://www.ncdc.noaa.gov. Upper-air data is also available from this site for select locations including Tucson, Flagstaff, Yuma and Winslow. In some cases, ADEQ allows the use of upper-air data from Desert Rock, Nevada and Albuquerque, New Mexico. Preprocessed, AERMOD-ready, meteorological data files are currently available for 16 meteorological sites across Arizona (Figure 1). ADEQ will maintain and update the existing processed AERMOD-ready meteorological database. ADEQ is planning to create a meteorological data website, from which applicants can access all meteorological data files as well as associated technical support documents. For further information and discussion regarding representativeness of the data for the area of interest, please contact ADEQ modeling staff.



▲ **ADEQ AERMET Meteorological Sites**

ZONE 1-4 **AZ Climate Zones**

Figure 1 Locations of ADEQ AERMET Meteorological Data Sets

3.8.1 Meteorological Data Description and Rationale

Appendix W states in Section 8.3.1.1 that the user should acquire enough meteorological data to ensure that worst-case conditions are adequately represented in the model results. Appendix W states that 5 years of NWS meteorological data or at least one year of site-specific data should be used(Section 8.3.1.2, Appendix W) and should be adequately representative of the study area.

Given the complex topography of Arizona and the remote locations of many facilities from population centers, existing meteorological data is often not representative of meteorological conditions at these facilities. If on-site meteorological data is unavailable for a given facility and the applicant wishes to model using meteorological data available from another location, the applicant must submit a detailed meteorological analysis to ADEQ for review. The meteorological analysis should explain how meteorological data from an offsite location is representative of the meteorological patterns around the facility. The applicant should discuss the differences/similarities in topography, climatology (especially wind patterns and mixing heights), and surface characteristics (surface roughness length, albedo, and Bowen ratio) between the two locations. The applicant should also explain why the utilization of offsite meteorological data would provide conservative modeling results.

If it is determined that representative meteorological data are not available, it will be necessary for the applicant to collect at least one (1) year of site-specific data. To generate a model-ready meteorological data set, the applicant merges monitored surface data with available upper-air data. **At the earliest stages of the air quality permitting process, it is important that the applicant communicate with ADEQ so that it can be determined whether or not meteorological monitoring will be necessary.** If meteorological monitoring is necessary, the monitoring should follow monitoring guidance and QA/QC guidance from USEPA. ADEQ relies upon the guidance provided in the document, *Meteorological Monitoring Guidance for Regulatory Modeling Applications* (U.S. EPA, 2000b). ADEQ relies upon the QA/QC guidance provided in EPA's *Quality Assurance Handbook for Air Pollution Measurement Systems* (five volume set).

If on-site meteorological monitoring is required, the following variables should be measured:

- Wind direction and wind speed at appropriate levels to characterize dispersion and transport of source emissions. Wind measurements should not be made lower than 10 meters above grade.
- Ambient temperature at 2 meters above grade
- Vertical temperature gradient
- Incoming solar radiation (insolation) or net solar radiation
- Pressure (optional but recommended)
- Precipitation (optional but recommended)
- Humidity (optional but recommended)

In some cases, an upper air monitoring with a SoDAR (Sonic Detection And Ranging) device may be required for collecting additional wind profile over the range of emission release and final plume heights.

3.8.2 Meteorological Data Processing

Surface and upper air data, provided by NWS or collected from specific sites, should be processed by AERMET (U.S. EPA, 2004d) and its accessory programs. AERMET processes commercially available or custom on-site met data and creates two files: a surface data file (SURFILE) and a profile data file (PROFILE). AERMET can extract data from several standard NCDC formats, including hourly surface observational data and twice-daily sounding data. Additional information on standard NCDC formats and meteorological data is available at http://www.ncdc.noaa.gov/oa/ncdc.html.

AERMINUTE

To reduce the number of calms and missing winds associated with the NWS meteorological data, EPA has developed a preprocessor to AERMET, called AERMINUTE (U.S. EPA, 2011c) that can read 2-minute ASOS winds and calculate an hourly average. Beginning with year 2000 data, NCDC has made the 1-minute wind data, reported every minute from the ASOS network freely available. The EPA's AERMINUTE program processes 1-minute ASOS wind data available from the National Climatic Data Center (NCDC) in the TD-6405 format to generate hourly averaged wind speed and wind direction to supplement the standard hourly ASOS observations. The hourly averaged wind speed and direction generated by the AERMINUTE program can be merged with data from standard surface archives, such as ISHD, along with upper air and site-specific data (if available) in Stage 2 of AERMET processing.

EPA recommends that AERMINUTE be routinely used to supplement the standard ASOS data with hourly-averaged wind speed and direction to support AERMOD dispersion modeling (U.S. EPA, 2013a). EPA also recommends using a minimum wind speed threshold of 0.5 m/s to the hourly averaged wind speeds provided by AERMINUTE (U.S.EPA, 2013a). To facilitate implementation of wind speed threshold in AERMET, EPA has added a wind speed threshold option in AERMET (version 12345) to treat winds below the threshold as calms.

In the near future, ADEQ will update pre-processed meteorological data sets with the supplemental AERMINUTE data.

AERSURFACE

The AERSURFACE program is used to obtain realistic and reproducible surface characteristic values, including albedo, Bowen ratio, and surface roughness length, for input to AERMET. When applying the AERMET meteorological processor (U.S. EPA, 2004d) to process meteorological data for the AERMOD model, the user must determine appropriate values for three surface characteristics: surface roughness length (z_o), albedo (r), and Bowen ratio (Bo). The surface roughness length is related to the height of obstacles to the wind flow and is, in principle, the height at which the mean horizontal wind speed is zero based on a logarithmic profile. The surface roughness length influences the surface shear stress and is an important factor in determining the magnitude of mechanical turbulence and the stability of the boundary layer. The albedo is the fraction of total incident solar radiation reflected by the surface back to space without absorption. The daytime Bowen ratio, an indicator of surface moisture, is the ratio of sensible heat flux to latent heat flux and, together with albedo and other meteorological observations, is used for determining planetary boundary layer parameters for convective conditions driven by the surface sensible heat flux.

The recommendations specified in the user's guide should be followed when generating surface characteristics data with AERSURFACE (U.S. EPA, 2008b). In particular, the following issues should be considered:

- Surface characteristics should be determined based on the meteorological measurement site rather than the facility application site.
- A current aerial photograph of the meteorological measurement site, or a detailed land-use map, should be used to check the accuracy of land-use files used in AERSURFACE.
- Default month assignments in AERSURFACE are not applicable to most areas in Arizona. Please contact ADEQ modeling staff regarding the month reassignments for a specific site.
- The moisture conditions (dry, wet, or normal) should be determined by comparing the moisture conditions for the period of meteorological data to be processed relative to climatological norms. Please note that locating in an arid region does not necessarily mean "dry" moisture conditions
- A default fetch radius of 1 km is specified in EPA guidance (AERSURFACE User's Guide). A non-default radius may be considered on a case-by-case basis.

3.9 Building Downwash and GEP Stack Height

Airflow over and around structures significantly impacts the dispersion of plumes from point sources. Modeling of point sources with stack heights that are less than good engineering practice (GEP) stack height should consider the impacts associated with building wake effects (also referred to as building downwash). Building downwash effects are not considered for non-point sources.

AAC R18-2-332 outlines stack height limitations. These limitations include a definition of GEP stack height. In the GEP definition, note that H_g = GEP stack height, H_b = height of nearby structure, and L = lesser dimension (height or projected width) of nearby structure.

GEP stack height is calculated as the highest of the following four numbers in subsections (1) through (4) below (**Table 5**):

Table 5 Calculation of GEP Stack Height

Subsections	GEP Stack Height
1	213.25 feet (65 meters),
2	For stacks in existence on January 12, 1979, and for which the owner of operator has obtained all applicable preconstruction permits of approvals required under 40 CFR 51 and 52 and AAC R18-2-403, Hg = 2.5Hb,
3	For all other stacks, Hg = Hb + 1.5L,
4	The height demonstrated by a fluid model or field study approved by the reviewing Agency, which ensures that the emissions from a stack do not result in excessive concentrations of any air pollutant as a result of atmospheric downwash, wakes, or eddy effects created by the source itself, nearby structures, or nearby terrain obstacles.

When calculating pollutant impacts, the AERMOD model has the capability to account for building downwash produced by airflow over and around structures. In order to do so, the model requires special input data known as direction-specific building dimensions (DSBDs) for all stacks below the GEP stack height. For more information on data requirements please refer to the AERMOD's User Guide (U.S. EPA 2004a).

Due to the complexity of the GEP guidance, the EPA has developed a computer program that calculates the downwash parameters called BPIPPRM, Building Profile Input Program for Plume Rise Model Enhancements (PRIME), which can be used for downwash analyses for input to the AERMOD model (U.S. EPA, 2004e). Currently, BPIPPRM can be downloaded from EPA's Support Center for Regulatory Air Models (SCRAM) website at http://www.epa.gov/ttn/scram.

The AERSCREEN model also incorporates the PRIME downwash algorithms that are part of the AERMOD refined model and utilizes the BPIPPRM tool to provide a detailed analysis of downwash influences on a direction-specific basis.

3.10 Background Concentrations

Background concentrations of regulated criteria pollutants must be included in NAAQS analyses for both PSD and non-PSD applications. In general, the background concentration is intended to account for sources not explicitly included in the modeling. These sources include (i) natural sources, (ii) nearby, non-modeled sources, and (iii) unidentified sources of air pollution (e.g., long-range transport). Background concentrations should be determined for each critical (concentration) averaging time and should be appropriate for the "averaging time of concern".

Background concentrations should be representative of regional air quality in the vicinity of a facility. In determining whether the existing air quality data are representative, EPA suggests that applicants consider three factors: (i) monitor location; (ii) data quality; and (iii) currentness (U.S. EPA, 1987b). Although this guidance is principally used for PSD sources, ADEQ believes this guidance is also helpful in assessing the representativeness of background concentrations for non-PSD sources as well.

Typically, background concentrations should be determined based on the air quality data collected in the vicinity of the proposed project site. If a "regional" monitor is used to determine background, a discussion should be provided to compare the topography, climatology, and emissions sources between the area of the proposed project and the area where the "regional" monitor is located. On a case-by-case basis, ADEQ may allow the applicant to use a data set obtained from other states if the data set is believed to be more representative. Note that some monitors are only running for a particular season (usually ozone season). Sufficient justification and documentation must be provided if a seasonal monitor is used for the background determination. If representative air quality data are unavailable, the applicant may use some conservative air quality data for the background determination. The applicant should explain why the utilization of these air quality data would provide a conservative estimate of the background concentration. If the applicant proposes determining background concentration by modeling background sources, please consult with ADEQ.

In Arizona, ambient monitoring is conducted by a number of governmental agencies and regulated industries. Each year, ADEQ compiles an annual monitoring report that summarizes monitored values from around Arizona. The reports also list active monitoring networks for various criteria pollutants.

Electronic copies of the AQD's annual air quality reports (required by A.R.S. §49-424.10) can be downloaded from ADEQ's website at:

http://www.azdeq.gov/function/forms/reports.html.

Currently, air quality annual reports containing monitoring data for the years 2000-2008 are available online. The most recent air monitoring data for Arizona can be obtained at the following website address:

http://www.epa.gov/airdata/.

ADEQ suggests that applicants select the background concentrations as described in **Table 6**. The most recent 3 years of ambient monitoring data should be used for background concentrations in NAAQS modeling analyses. Background concentrations should be representative of regional air quality in the vicinity of a facility. For more information, please refer to the *Guideline on Air Quality Models.*

Table 6 Determination of Background Concentrations

NAAQS Pollutant	Averaging Time	NAAQS Level	NAAQS Form	Background Form
Carbon Monoxide	8-Hour	9 ppm	Not to be exceeded more than once per year	Highest concentration during most recent 3 years
	1-Hour	35 ppm		
Lead	Rolling 3 Month Average	0.15 µg/m^3	Not to be exceeded	Highest concentration during most recent 3 years
Nitrogen Dioxide (NO_2)	1-Hour[a]	100 ppb	98th percentile of the annual distribution of the 1-hour daily maximum concentrations, averaged over 3 years	98th percentile of the annual distribution of daily maximum 1-hours values averaged across the most recent three years
	Annual	53 ppb	Annual Mean	Highest annual concentration for most recent 3 years
Ozone	8-Hour	0.075 ppm	Annual fourth-highest daily maximum 8-hr concentration, averaged over 3 years	Not Applicable
$PM_{2.5}$	Annual (primary)	12 µg/m^3	Annual mean, averaged over 3 years	Average of the annual values over most recent 3 years
	Annual (secondary)	15 µg/m^3	Annual mean, averaged over 3 years	Average of the annual values over most recent 3 years
	24-Hour[b,c]	35 µg/m^3	98th percentile, averaged over 3 years	Average of the 98th percentile 24-hour values over most recent 3 years
PM_{10}	24-Hour[b]	150 µg/m^3	Not to be exceeded more than once per year on average over 3 years	Average of the highest yearly values for most recent 3 years
Sulfur Dioxide (SO_2)	1-Hour[a]	75 ppb	99th percentile of the annual distribution of the 1-hour daily maximum concentrations, averaged over 3 years	99th percentile of the annual distribution of daily maximum 1-hours values averaged across the most recent three years
	3-hour	0.5 ppm	Not to be exceeded more than once per year	Highest concentration during most recent 3 years

[a] *Monthly/Seasonal/Annual hour-of-day monitored background concentrations may be used in some refined analyses. See Sections 7.1.4 and 7.2.3 for details*.

[b] *Seasonal background concentrations may be used in some refined analyses. See Section 7.3.5 for details.*

[c] *Monitored concentrations on a day-by-day basis may be used in some refined analyses. See Section 7.4.1 for details.*

Additionally, ADEQ occasionally requires that applicants monitor one year of background data for particular criteria pollutants from a representative on-site location for PSD modeling analyses. At the earliest stages of the air quality permitting process, it is important that the applicant communicate with ADEQ so that it can be determined whether or not background monitoring will be necessary. If background monitoring is necessary, the monitoring should follow monitoring guidance and QA/QC guidance from EPA. ADEQ relies upon the monitoring guidance provided in the *Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD)* (U.S. EPA, 1987b). ADEQ also relies upon the QA/QC guidance provided in EPA's *Quality Assurance Handbook for Air Pollution Measurement Systems* (five volume set).

3.11 Modeled Design Concentrations

In a compliance demonstration, the applicable modeled design concentration must be calculated. **Table 7** provides the summary of modeled design concentrations for individual criteria pollutants. It is worth mentioning that EPA has changed its recommendations on calculating modeled design concentration for 24-hour $PM_{2.5}$. The March 23, 2010, clarification memo (U.S. EPA, 2010c) recommended that the modeled design concentration should be based on the highest average of the modeled 24-hour averages across 5 years for representative NWS data or the highest modeled average for one year (or multi-year average of 2 up to 5 complete years) of site-specific meteorological data. In the recent draft $PM_{2.5}$ modeling guidance (U.S. EPA, 2013b), however, it was recommended to use the multi-year average of the 98^{th}-percentile of 24-hour values instead of the highest average.

Table 7 Modeled Design Concentrations

NAAQS Pollutant	Averaging Time	Modeled Design Concentration	Reference
Carbon Monoxide	8-Hour	Highest, second highest concentrations over the entire receptor network for each year modeled [a]	40 CFR Appendix W 7.2.1 (U.S. EPA, 2005)
	1-Hour	Highest, second highest concentrations over the entire receptor network for each year modeled [a]	40 CFR Appendix W 7.2.1 (U.S. EPA, 2005)
Lead	Rolling 3 Month Average	Highest modeled concentration over the entire receptor network regardless of one year or multiple years of meteorological data are used	40 CFR Appendix W 7.2.1 (U.S. EPA, 2005)
Nitrogen Dioxide (NO_2)	1-Hour	- Highest of multi-year averages of the 98^{th} percentile of the annual distribution of maximum daily 1-hour concentrations predicted each year at each receptor, if multiple years of meteorological data are used; - Highest of the 98^{th} percentile of the annual distribution of maximum daily 1-hour concentrations predicted at each receptor if one year of meteorological data are used	Tyler Fox Memorandum dated June 28, 2010 (U.S. EPA, 2010a) and Tyler Fox Memorandum dated March 1, 2011 (U.S. EPA, 2011d)
	Annual	Highest modeled concentration over the entire receptor network regardless of one year or multiple years of meteorological data are used	40 CFR Appendix W 7.2.1 (U.S. EPA, 2005)
$PM_{2.5}$	Annual	- Highest of multi-year averages of annual concentrations at each receptor if multiple years of meteorological data are used - Highest annual concentration over the entire receptor network if one year of meteorological data is used	Stephen Page Memorandum dated March 4, 2013 (U.S. EPA, 2013b)
	24-Hour	- Highest of multi-year averages of the 98^{th} percentile of the annual distribution of 24-hour concentrations predicted each year at each receptor, if multiple year meteorological data are used; - Highest of the 98^{th} percentile of the annual distribution of 24-hour concentrations predicted at each receptor if one year of meteorological data are used	Stephen Page Memorandum dated March 4, 2013 (U.S. EPA, 2013b)
PM_{10}	24-Hour	The design concentration is dependent on the number of meteorological data years used in the analysis. In general, the (n+1)th highest concentration over the n-year period is the design value. For example, if five years of meteorological data are used, then the design concentration would be highest, sixth highest 24-hour modeled concentration that occurred at each receptor over that five-year period.	40 CFR Appendix W 7.2.1(U.S. EPA, 2005)
Sulfur Dioxide (SO_2)	1-Hour	- Highest of multi-year averages of the 99^{th} percentile of the annual distribution of maximum daily 1-hour concentrations predicted each year at each receptor, if multi-year meteorological data are used; - Highest of the 99^{th} percentile of the annual distribution of maximum daily 1-hour concentrations predicted at each receptor if one year meteorological data is used	Tyler Fox Memorandum dated August 23, 2010. (U.S. EPA, 2010b)
	3-hour	Highest, second highest concentrations over the entire receptor network for each year modeled [a]	40 CFR Appendix W 7.2.1(U.S. EPA, 2005)

[a] *If multi-year meteorological data are used, determine H2H for each year and then select the highest concentration as the modeled design concentration .*

4 ADEQ PERMITTING JURISDICTION AND CLASSIFICATIONS

4.1 Air Quality Permitting Jurisdiction in Arizona

Of Arizona's 15 counties, three counties (Maricopa, Pinal, and Pima) ("local agency", have obtained US EPA approval to regulate sources of air pollution within their county. ADEQ has jurisdiction in the other 12 counties. Unless the source falls under a category exclusively under ADEQ jurisdiction (regardless of location), such as (1) the smelting of metal ore, (2) petroleum refineries, (3) coal-fired electrical generating stations, (4) Portland cement plants, (5) other sources over which the State has asserted jurisdiction, these permitting authorities should be consulted directly for proposed projects that operate solely within their counties:

- Maricopa County (http://www.maricopa.gov/aq/)
- Pima County (http://www.deq.pima.gov/air/index.html)
- Pinal County (http://pinalcountyaz.gov/Departments/AirQuality/Pages/Home.aspx

Figure 2 provides map of counties, major highways, and selected towns and cities in Arizona.

Portable sources are permitted by ADEQ for operations in Arizona that do not solely operate within Maricopa, Pinal, or Pima counties during the permit term. Portable sources that solely operate within Maricopa, Pinal, or Pima County should obtain an air quality permit from the local agency.

Most Native American Reservations are under the jurisdiction of the federal Environmental Protection Agency. Some tribes in Arizona have US EPA approved air pollution control programs. More information regarding tribal programs can be found at:

- EPA Region 9 Tribal Air Programs in the Pacific Southwest (http://www.epa.gov/region9/air/tribal/index.html)
- Gila River Indian Community (http://www.gric.nsn.us/)
- Fort McDowell Yavapai Nation (http://www.ftmcdowell.org/)
- Navajo Nation (http://www.navajo.org/)
- Salt River Pima-Maricopa Indian Community (http://www.saltriver.pima-maricopa.nsn.us/)

Additional information regarding many of Arizona's tribes is available through the Intertribal Council of Arizona (http://www.itcaonline.com/). **Figure 3** displays the locations of tribal lands located in Arizona.

4.2 Main ADEQ Permit Classifications

ADEQ oversees modeling for both state and federal air quality permits. ADEQ refers to permits for minor sources as Class II permits. Major source permits are referred to as Class I permits. Modeling analyses may be required by ADEQ for the following permit types:

- Class I Permits
  - All Prevention of Significant Deterioration Determinations
  - All New Source Review Determinations
  - All other types of new major source permits
  - All permit revisions that increase the potential to emit pollutants greater than the permitting exemption threshold
- Class II Permits
  - All new minor source and synthetic minor source permits
  - All permit revisions that increase the potential to emit pollutants greater than the permitting exemption threshold

Table 8 lists the permitting exemption thresholds for criteria pollutants.

Table 8 Permitting Exemption Thresholds

Pollutant	Permitting Exemption Thresholds (tons per year)
PM_{10}	7.5
$PM_{2.5}$	5
SO_2	20
NO_x	20
VOC	20
CO	50
Lead	0.3

ADEQ is currently seeking approval of a rule package from the Environmental Protection Agency to update its minor New Source Review program. Upon approval by EPA, R18-2-334 of the A.A.C. will provide an opportunity to Permittees to address minor NSR changes by conducting a NAAQS modeling exercise or to conduct a Reasonable Available Control Technology (RACT) analysis. Notwithstanding the Permittee's election to conduct a RACT analysis, the Director may subject the Permittee to conduct a NAAQS analysis if a source or a minor NSR modification has the potential to contribute to a violation of the NAAQS.

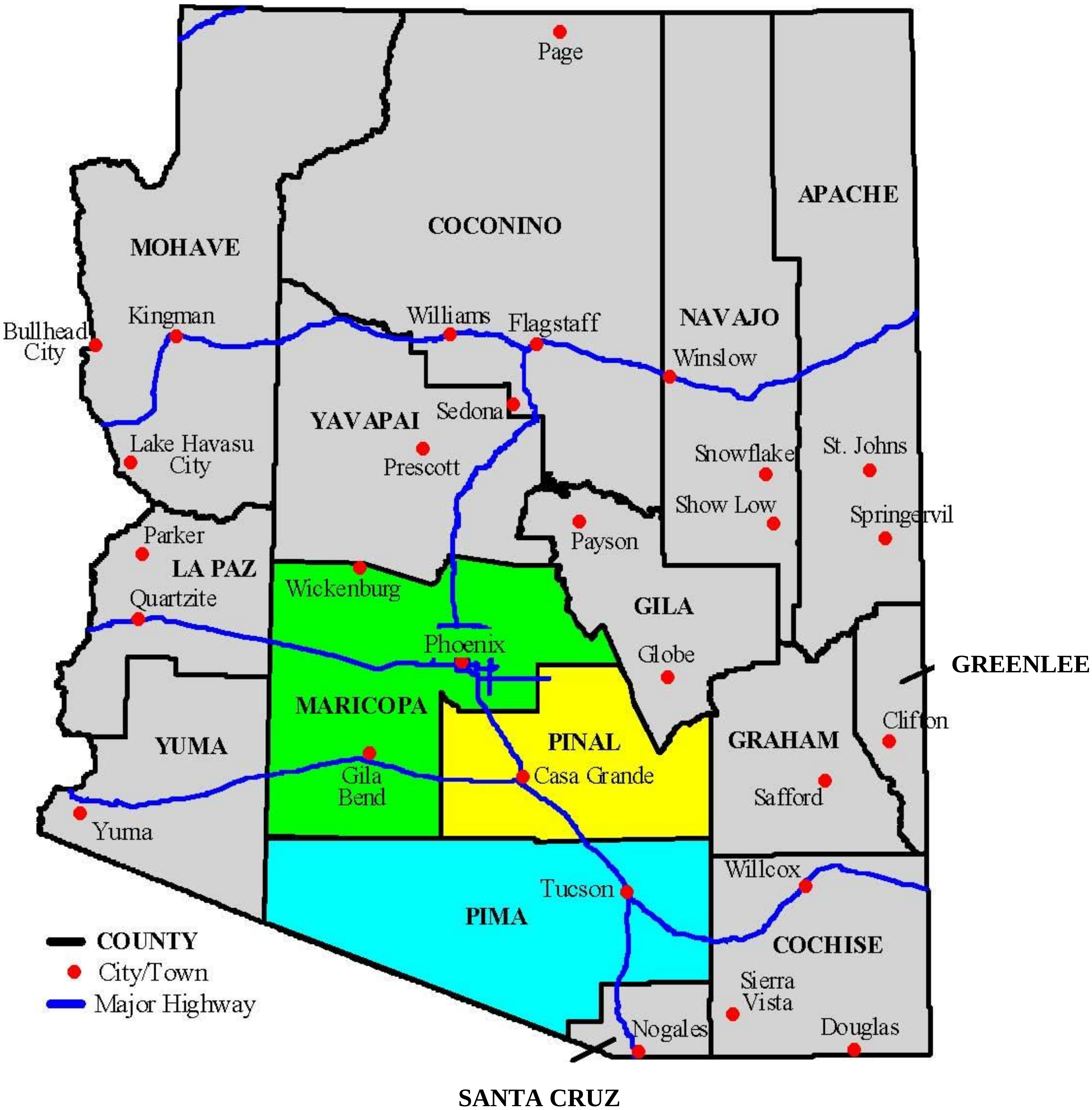


Figure 2 Map of Arizona

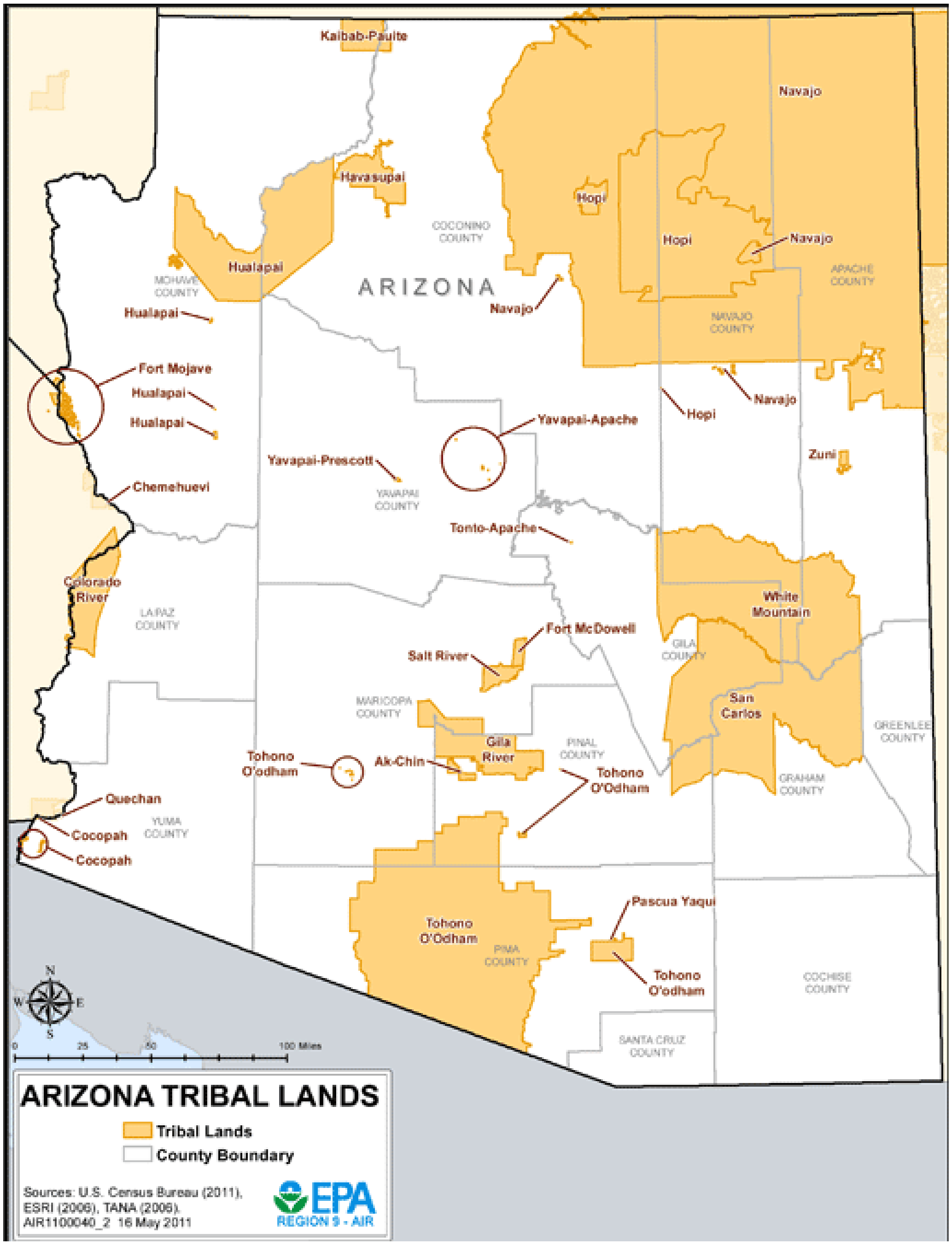


Figure 3 Tribal Lands in Arizona

5 MODELING REQUIREMENTS FOR NON-PSD SOURCES

For non-PSD sources, ADEQ requires that applicants model criteria pollutant impacts for comparison to the NAAQS (National Ambient Air Quality Standards). This section provides more information on non-PSD NAAQS modeling in effect until the Administrator approves R18-2-334 (Minor New Source Review).

For non-PSD sources, representative background concentrations (see Section 3.9) should be added to modeled impacts from the applicant's proposed new or modified source. Unlike the methods used in NAAQS analyses for PSD permit applications, inclusion of regional sources in the non-PSD NAAQS is typically not required. However, on a case-by-case basis, ADEQ reserves the right to request modeling which includes the non-PSD source in question and additional nearby or regional sources.

If the model indicates that a NAAQS is initially exceeded, it is the responsibility of the applicant to consider several options to limit the NAAQS exceedance. Preliminary NAAQS exceedances might be reduced by:

- Refining emissions estimates by using other defensible emission factors than those used in the preliminary modeling analysis,
- Limiting operational hours or process throughputs,
- Optimizing stack parameters for better pollutant dispersion (i.e. raise stack heights, increase exhaust airflows (subject to restrictions on prohibited dispersion techniques), or crown stack diameters to obtain higher exhaust velocities),
- Relocating sources to other portions of a facility which would lead to lower modeled impacts,
- Source testing to refine emissions estimates,
- Installing pollution controls to limit emissions.

Note that the EPA's "prohibited dispersion techniques" as defined in 40 CFR 51.100 (hh)(1)(i)-(iii) should not be used.

6 MODELING REQUIREMENTS FOR PSD SOURCES

The following section reviews ADEQ's requirements for sources that are subject to PSD regulations. The PSD regulation is targeted for individual pollutants. If any of the pollutants emitted by a source is above the threshold level for PSD, the source is subject to PSD for that pollutant. Those pollutants that are below the threshold level are not subject to PSD.

6.1 NAAQS Analyses for Pollutants That Do Not Trigger PSD

For criteria pollutants at a PSD source that do not trigger PSD requirements, representative background concentrations (see Section 3.10) should be added to modeled impacts from the applicant's facility only. Inclusion of regional sources in the NAAQS analysis for a pollutant that does not trigger PSD is typically not required.

6.2 Overview of PSD Modeling Procedures

For PSD triggering pollutants, ADEQ requires that applicants follow EPA's *New Source Review Workshop Manual* (U.S. EPA, 1990) and other applicable PSD guidance set forth in the EPA's *Guideline on Air Quality Models* to complete the air quality impact analysis. The *Draft New Source Review Workshop Manual* (see Chapters C, D, and E) provides a good overview and examples of modeling analyses required for sources that trigger PSD. http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf

The PSD modeling analysis is performed in two steps: a preliminary analysis (often referred to as a significant impact analysis), and if required, a full impact analysis. The preliminary analysis estimates ambient concentrations resulting from the proposed project for pollutants that trigger PSD requirements. For this analysis, a loads analysis should be performed to determine that project impacts are not underestimated.

The results of the preliminary analysis determine whether an applicant must perform a full impact analysis for a particular pollutant. If the ambient impacts from the preliminary analysis are greater than the PSD Significant Impact Levels (SILs, see **Table 9**), then the extent of the Significant Impact Area (SIA) of the proposed project is determined. Initially, the SIA is determined for every relevant averaging time for a particular pollutant. The final SIA for that pollutant is the largest area for each of the various averaging times.

The preliminary, facility-only impact analysis involves modeling impacts for comparison to both the PSD Class II Significant Impact Levels and Significant Monitoring Concentration (SMC) Levels as shown in **Table 9**. If the facility-only impacts exceed the SMC levels, then pre-application air quality monitoring may be required. Note that on January 22, 2013, the U.S. Court of Appeals for the District of Columbia vacated parts of the PSD rules establishing the SMC for $PM_{2.5}$, thereby precluding the use of the SMC as a "de minimis" level to avoid pre-construction monitoring for $PM_{2.5}$. Due to the nature of this court decision, there may be legal bearing on the use of SMCs for pollutants other than $PM_{2.5}$. In a brief summary of the court decision issued on January 29, 2013, EPA states that "given the court's broadly stated holding that SMCs are not permissible, the EPA is also assessing the decision's impact on SMCs for other pollutants". The outcome of EPA's assessment is still pending and therefore the full impact of the court decision on the use of SMCs to avoid pre-construction monitoring for other pollutants is uncertain at this time. Until the federal rules implementing the SMCs are legally revised, ADEQ recommends continued use of the SMCs for all pollutants except for $PM_{2.5}$. Alternatively, sources may avoid the implications of the court ruling by demonstrating that adequate, representative monitoring data to establish background conditions for the facility are available.

Table 9 PSD Increments, Significant Emission Rates, Modeling Significance Levels, and Monitoring De Minimis Concentrations

Pollutant	**Averaging Period**	**PSD Significant Emission Rates (tons/year)**	**PSD Increment (μg/m³)**			**Significant Impact Level (μg/m³)**		**Monitoring De Minimis Concentrations (μg/m³)**
			Class I	**Class II**	**Class III**	**Class I**	**Class II**	
PM_{10}	24-hour	15	8	30	60	0.3	5	10
$PM_{2.5}$	24-hour	10 (40[a])	2	9	18	0.07[b]	1.2[b]	
	Annual		1	4	8	0.06[b]	0.3[b]	
NO_2	1-hour	40 of NOx					7.5[c]	
	Annual		2.5	25	50	0.1	1	14
SO_2	1-hour	40					7.8[d]	
	3-hour		25	512	700	1	25	
CO	1-hour	100					2,000	
	8-hour						500	575
Ozone	8-hour	40 of VOC						VOC emissions increase > 100 tpy
Lead	Rolling 3 month average	0.6						0.1

[a] SO_2, NOx, and VOCs as precursors
[b] SILs may be used under some circumstances (see Section 7.3)
[c] Interim 1-hour SIL, 4 ppb
[d] Interim 1-hour SIL, 3 ppb

The full impact analysis expands the preliminary impact analysis by considering emissions from both the proposed project as well as other sources in the SIA. The full impact analysis may also consider other sources outside the SIA that could cause significant impacts in the SIA of the proposed source. The results from the full impact analysis are used to demonstrate compliance with NAAQS and PSD increments. The source inventory for the cumulative NAAQS analysis includes all nearby sources that have significant impacts within the proposed source SIA, while the source inventory for the cumulative PSD increment analysis is limited to increment-affecting sources (new sources and changes to existing sources that have occurred since the applicable increment baseline date).

The full impact analysis is limited to receptor locations within the proposed project's SIA. The modeling results from the NAAQS cumulative impact analysis are added to representative ambient background concentrations and the total concentrations are compared to the NAAQS. Conversely, the modeled air quality impacts for all increment-consuming sources are directly compared to the PSD increments to determine compliance (without consideration of ambient background concentrations).

6.2.1 NAAQS Modeling Inventory

In addition to modeling the proposed source and adding background values, EPA requires that, at a minimum, all nearby sources be explicitly modeled as part of the full NAAQS analysis for PSD. The *Guideline on Air Quality Models* defines a nearby source as any point source expected to cause a significant concentration gradient in the vicinity of the proposed new source or modification. For PSD purposes, vicinity is defined as the significant impact area (SIA) for each pollutant. However, the location of such nearby sources could be anywhere within the significant impact area or an annular area extending 50 kilometers beyond the SIA.

For the full NAAQS modeling analyses, all permitted sources within the SIA must be explicitly modeled. In addition, all permitted sources located outside the SIA and within the annular area extending 50 km from the SIA must also be included if they have a potential to affect air quality near the proposed source, as described in Chapter C, Section IV.C.1 of the *Draft New Source Review Workshop Manual* (U.S. EPA, 1990). The inclusion of a regional source can be determined by using the '20D' approach (also followed by Ohio EPA), also known as the North Carolina Protocol. The "20D" approach assumes a linear inverse proportional relationship between source emissions and impacts with distance. A "20D" facility-level screening approach is used to eliminate a majority of regional facilities from the PSD NAAQS modeling analysis that would not be expected to have a significant impact on analysis results. Under this approach, the applicant may exclude sources that have potential allowable emissions (Q) in tons/yr that are less than 20 times the distance ("20D") between the two sources in kilometers. Those sources that are not eliminated using the "20D" approach should be modeled in the full NAAQS analysis.

Cumulative impact assessments based on the procedures above will generally be acceptable as the basis for permitting decisions. However, in the recent 1-hour NO_2 modeling guidance (U.S.EPA, 2011d) and draft $PM_{2.5}$ modeling guidance (U.S. EPA, 2013b), EPA cautions against the literal and uncritical application of very prescriptive procedures for identifying which nearby sources should be included in the modeled emission inventory for NAAQS compliance demonstrations, such as described in the draft New Source Review Workshop Manual. EPA suggests that the emphasis on determining which nearby sources to include in the cumulative modeling analysis should focus on the area within about 10 kilometers of the project location in most cases. However, several application-specific factors should be considered when determining the appropriate inventory of nearby sources to include in the cumulative modeling analysis, including the potential influence of terrain characteristics on concentration gradients, and the availability and adequacy of ambient monitoring data to account for background sources. Sufficient justification must be provided if the applicant proposes using a 10 km radius of background sources in the modeled emission inventory.

The ADEQ State Implementation Plan (SIP) Section provides regional source emission inventories to permit applicants. The appropriate contact in the SIP Section can be reached at 602-771-7665.

6.2.2 Increment Modeling Inventory

A PSD increment is the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for a pollutant. The baseline concentration is defined for each pollutant (and relevant averaging time) and, in general, is the ambient concentration existing at the time that the first complete PSD permit application affecting an area is submitted. Significant deterioration is said to occur when the amount of new pollution would exceed the applicable PSD increment.

According to PSD Guidelines, the increment inventory to be considered in the modeling analysis includes all increment-affecting sources located within the SIA of the proposed new source or modification. In addition, all increment-affecting sources located within 50 kilometers of the SIA should also be included in the inventory if they, either individually or collectively, affect the amount of PSD increment consumed.
In general, the stationary sources of concern for the increment inventory are those stationary sources with actual emissions changes occurring since the minor source baseline date. However, it should be noted that certain actual emissions changes occurring before the minor source baseline date (i.e. at major stationary point sources) also affect the increments. To clarify, the types of stationary point sources that should be initially reviewed to determine the need to include them in the increment inventory fall under two specific time frames:

After the major source baseline date:

- Existing major stationary sources having undergone a physical change or change in their method of operation
- New major stationary sources

After the minor source baseline date:

- Existing stationary sources having undergone a physical change or change in their method of operation
- Existing stationary sources having increased hours of operation or capacity utilization (unless such change was considered representative of baseline operating conditions)

The *Draft New Source Review Workshop Manual* (U.S. EPA, 1990) provides details regarding the major source baseline date, trigger date, and minor source baseline dates. The major source baseline date and trigger dates are fixed. The major source baseline dates are shown in **Table 10**.

Table 10 Major Source Baseline Dates

Pollutant	**Major Source Baseline Date**	**Trigger Date**
PM_{10}	January 6, 1975	August 7, 1977
$PM_{2.5}$	October 20,2010	October 20, 2011
SO_2	January 6, 1975	August 7, 1977
NO_2	February 8, 1988	February 8, 1988

In contrast, the minor source baseline dates vary for each Arizona air quality control region (AQCR). The minor source baseline date is the earliest date after the trigger date on which a complete PSD application is received by the permit-reviewing agency. **Table 11** presents the minor source baseline dates for Arizona's six AQCRs. **Figure 4** displays the AQCRs in Arizona. The minor source baseline dates for $PM_{2.5}$ are currently unavailable and will be developed in the future.

Table 11Minor Source Baseline Dates for Arizona AQCRs

Air Quality Control Region (AQCR)	**Counties Included In AQCR**	**Minor Source Baseline Dates**		
		PM_{10}	**SO_2**	**NO_2**
Central Arizona Intrastate	Gila, Pinal	February 1, 1979	April 18, 1988	April 26, 1996
Maricopa Intrastate	Maricopa	March 3, 1980	March 3, 1980	January 20, 1993
Northern Arizona Intrastate	Apache, Coconino, Navajo, Yavapai	October 31, 1977	October 31, 1977	August 15, 1990
Pima Intrastate	Pima	not triggered	not triggered	not triggered
Southeast Arizona Intrastate	Cochise, Graham, Greenlee, Santa Cruz	April 5, 2002	April 5, 2002	April 5, 2002
Mohave-Yuma Intrastate	La Paz, Mohave, Yuma	July 15, 1998	March 15, 1999	April 10, 1991

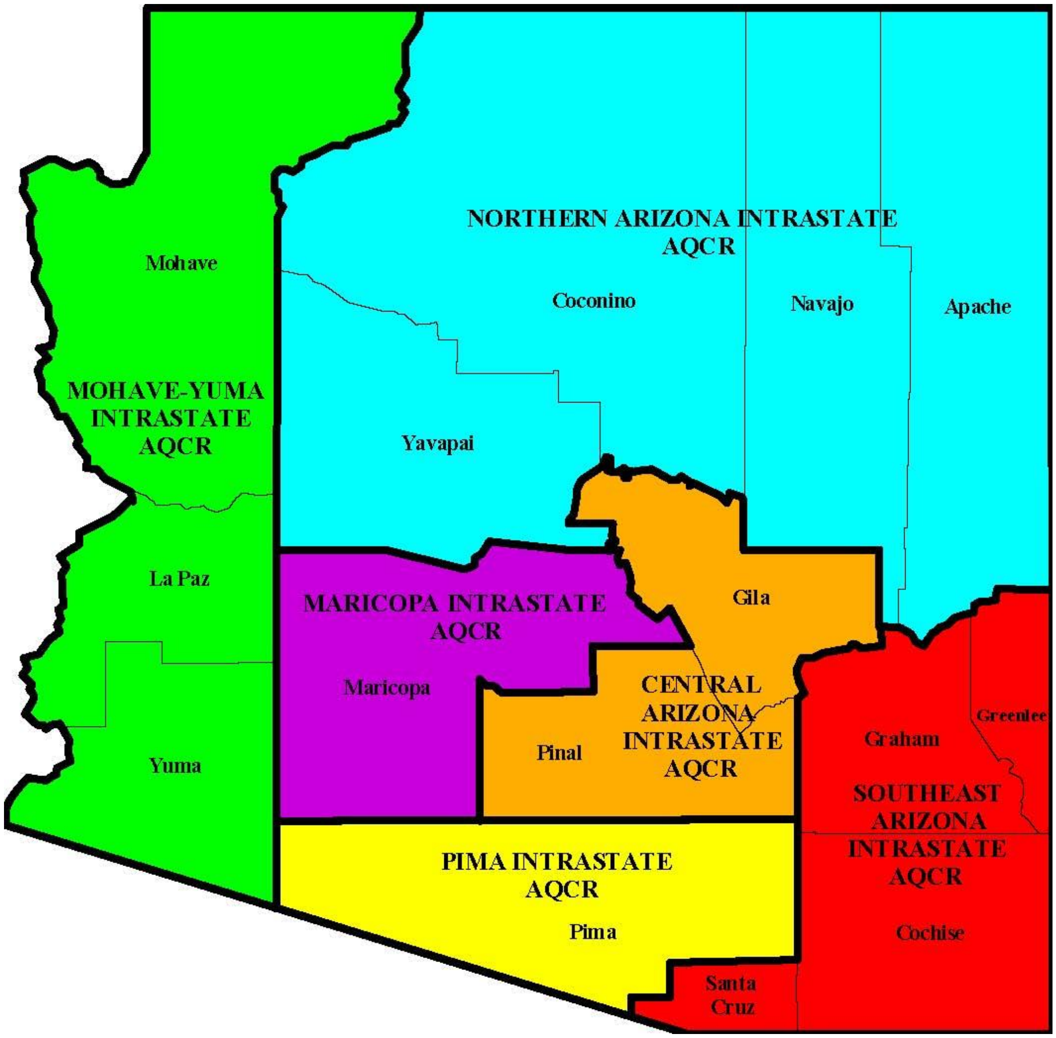


Figure 4 Air Quality Control Regions in Arizona

6.2.3 Additional Impact Analyses

PSD permit applicants must prepare additional impact analyses for each PSD triggering pollutant. These additional analyses assess the impacts of air, ground, and water pollution on soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant from the source or modification under review, and from associated growth. Details regarding these analyses can be found in Chapter D of the *Draft New Source Review* Workshop Manual (U.S. EPA, 1990).

6.2.4 Class I Area Impact Analyses

The Federal Land Manager's Air Quality Related Values Work Group (FLAG) was formed to develop a more consistent approach for the Federal Land Managers (FLMs) to evaluate air pollution effects on their resources. Of particular importance are the New Source Review (NSR) program and the review of PSD air quality permit applications. FLAG's goals are to provide consistent policies and processes for identifying air quality related values (AQRVs) and for evaluating the effect of air pollution on AQRVs, primarily those in Federal Class I air quality areas, but in some instances, in Class II areas. Federal Class I areas are defined in the Clean Air Act as national parks over 6,000 acres and wilderness areas and memorial parks over 5,000 acres that were established as of 1977. All other federally managed areas are designated as Class II.

40 CFR 51.307 requires the operator of any new major stationary source or major modification that may affect visibility in any Federal Class I area to contact the FLM for that area. It should be addressed that, there is no absolute distance cutoff for FLM notification because the Clean Air Act (CAA) does not establish any distance criteria with respect to the FLMs' "affirmative responsibility" to protect AQRVs in Class I areas. EPA guidance states that permitting authorities should notify the FLM of all sources proposing to locate within 100 km of a Class I area, and of "very large sources" locating greater than 100 km if they have the potential to affect Class I areas (U.S. EPA, 1979). The FLAG guidance document recommends that applicants conduct an analysis of the AQRV's for Class I areas within 300 km of a source. However, the distance of 300 km is based on the modeling capabilities of CALPUFF rather than any laws or regulations.

Class I increments have been established for PM_{10}, $PM_{2.5}$, SO_2, and NO_2 and are listed in **Table 9**. These represent the maximum increases in ambient pollutant concentrations allowed over baseline concentrations. The class I increment analysis should be conducted using the same modeling methodology as that used in the Class II area analysis and may incorporate the use of long range transport models such as CALPUFF.

The FLAG guidance document (FLAG Phase 1 Report, 2010; FLAG, 2011) should be followed when conducting an AQRV impact analysis. For sources located or proposing to locate greater than 50 km from a Class I area, applicants may choose to utilize the $Q/D \leq 10$ initial screening criteria, in accordance with the FLAG 2010 guidance document, to determine whether further AQRV analysis is required. However, it should be noted that this screening approach is for AQRVs only (e.g. visibility) and is not applicable for Class I increment analyses. See the Federal Land Managers' Air Quality Related Values Work Group (FLAG) for more information at:
http://www2.nature.nps.gov/air/Permits/flag/index.cfm

For long-range modeling with CALPUFF, the most recent and readily available Penn State/NCAR Mesoscale Model (MM5) or Weather Research and Forecasting (WRF) data should be used to generate metrological data files with grid spacing no less than 4 km to ensure proper wind field development. Regarding CALMET settings, please use EPA-FLM recommended CALMET input files values (U.S. EPA, 2009b). Mesoscale

Model Interface Program (MMIF), which converts prognostic meteorological model output fields to the parameters and formats required for direct input into dispersion models, should not be used for regulatory purposes unless EPA provides appropriate guidance and other support for such use.

During the PSD permitting process, the permit applicant should work closely with the FLM to address any AQRV related concerns. **Table 12** lists the name of each Class I area located in Arizona and the managing agency responsible for each. **Figure 5** shows the locations of Class I areas in Arizona.

Table 12 Class I Areas Located in Arizona

Class I Area	Managing Agency
National Parks	
Grand Canyon	National Park Service
Petrified Forest	National Park Service
National Wilderness Areas	
Chiricahua National Monument	National Park Service
Chiricahua	Forest Service
Galiuro	Forest Service
Mazatzal	Forest Service
Mt. Baldy	Forest Service
Pine Mountain	Forest Service
Saguaro National Monument	National Park Service
Sierra Ancha	Forest Service
Superstition	Forest Service
Sycamore Canyon	Forest Service

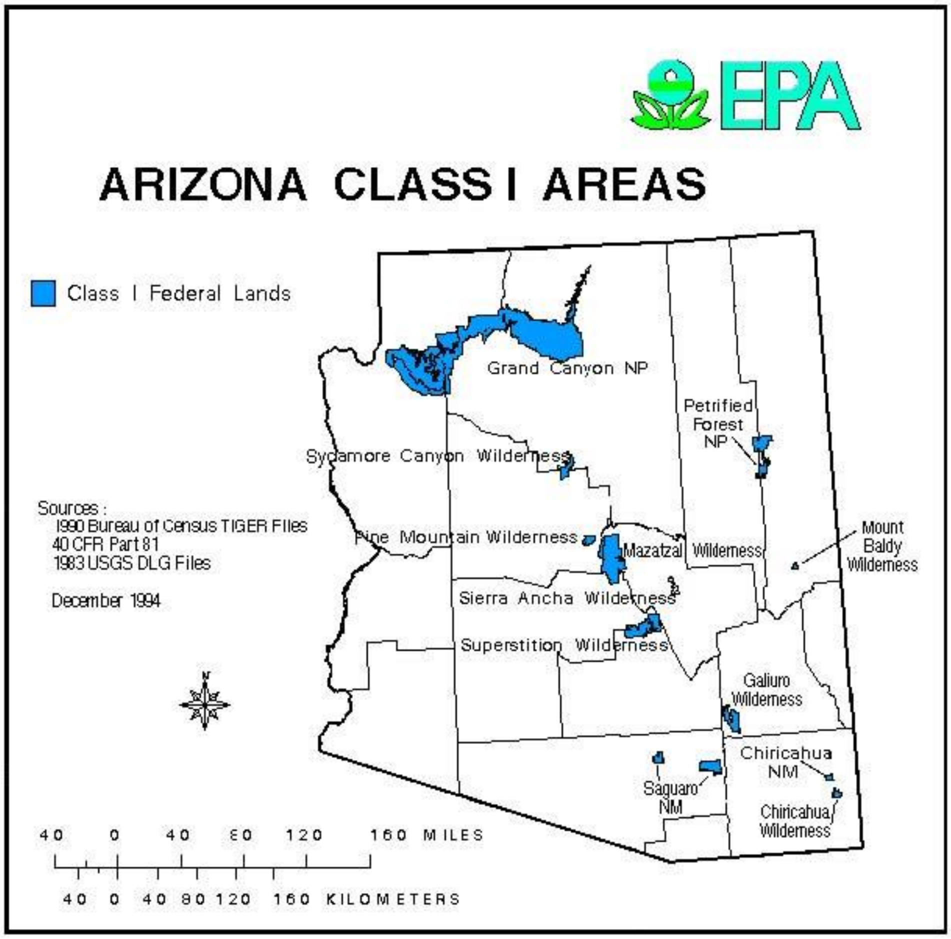


Figure 5 Class I Areas in Arizona

7 SPECIAL MODELING ISSUES

7.1 Modeling for 1-hour NO_2

On January 22, 2010, EPA established a new 1-hour National Ambient Air Quality Standard (NAAQS) for Nitrogen Dioxide (NO_2) at 100 parts per billion (ppb) (approximately 189 $\mu g/m^3$). The new 1-hour standard is calculated as the three-year average of the 98th percentile of daily maximum 1-hour average concentrations of NO_2. To demonstrate compliance with EPA's new 1-hour NO_2 NAAQS, air quality dispersion modeling analysis must be performed to show that emissions from a source will not cause or contribute to a violation of the standard. Since the 1-hour NO_2 standard is much more stringent than the previous NAAQS, it has been found that demonstrating compliance with the new standard is significantly challenging, particularly for short stacks and small facility footprints (AIWG, 2012).

To assist sources and permitting authorities in carrying out the required air quality analysis for 1-hour NO_2 compliance demonstrations, EPA has issued two guidance memorandums:

- Applicability of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard (U.S. EPA, 2010a);

- Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard (U.S. EPA, 2011d).

While the two memorandums are specifically for major sources and major modifications that are subject to Prevention of Significant Deterioration (PSD) requirements, ADEQ believes that some principles and guidance can apply to minor sources, in part, to ensure consistency of treatment in permitting and to ensure that it is not imposing different requirements on minor sources than those to which PSD sources are subject.

The following guidance describes ADEQ's requirements and recommended procedures for 1-hour NO_2 permit modeling. Due to the technical issues associated with 1-hour NO_2 modeling, the guidance will be amended periodically to incorporate new modeling guidance developed by EPA.

7.1.1 Emission Rate

For sources modeled to determine compliance with the 1-hour NO_2 NAAQS, the maximum 1-hour emission rates must be used unless otherwise discussed or otherwise approved by ADEQ. For example, an emission rate lower than the maximum 1-hour rate may be used if it will be enforceable through a permit condition. For modeling some intermittent sources with an uncertain operating frequency, ADEQ may also allow using an annualized hourly emission rate rather than the maximum hourly emission rate (see **Section 7.1.6**).

7.1.2 Significant Impact Level

The EPA's interim significant impact level (SIL) (4 ppb, 7.5 $\mu g/m^3$) for 1-hour NO_2 should be used unless EPA promulgates an official 1-hour NO_2 SIL. To determine whether a cumulative impact assessment is needed for PSD sources, the interim SIL should be compared to the highest of the 5-year average of the maximum modeled 1-hour NO_2 concentrations predicted at each receptor (if multiyear meteorological data are used) or the highest modeled 1-hour NO_2 concentration (if one-year meteorological data are used).

7.1.3 Three-tiered Approach for 1-hour NO_2 Modeling

Based on the EPA's memorandums dated June 28, 2010 and March 01, 2011, the following three-tiered approach is recommended for 1-hour NO_2 modeling:

- Tier 1 Total Conversion - assuming full conversion of NO to NO_2 without any additional justification.

- Tier 2 Ambient Ratio Method (ARM) - multiply Tier 1 result by empirically-derived NO_2/NOx ratio, with 0.8 as default ambient ratio for the 1-hour NO_2 standard without additional justification. Note that the national annual default for NO_2/NOx ratio is 0.75.

- Tier 3 - Plume Volume Molar Ratio Method (PVMRM)/ Ozone Limiting Method (OLM) - the two approaches are available as non-regulatory-default options within the AERMOD model. Both of these options account for ambient conversion of NO to NO_2 in the presence of ozone, namely the ozone titration mechanism. The main distinction between PVMRM and OLM is the approach taken to estimate the ambient concentration of NO and O_3 for which the ozone titration mechanism should be applied. Since the EPA's memorandums do not indicate any preference between the two options, it is the applicant's responsibility to justify which method is more suitable, if the Tier 3 approach is used.

  Two key model inputs for both the PVMRM and OLM options, namely in-stack ratios of NO_2/NO_X emissions and background ozone concentrations, will be discussed in detail later. For OLM, the "OLMGROUP ALL" option should be used if multiple sources are modeled. Per EPA's guidance, the ambient equilibrium ratio is 0.9 for both OLM and PVMRM.

7.1.4 Determining Background Concentrations

Background Concentration for 1-hour NO_2

In general, the guidance in Section 3.10 should be followed when determining background concentrations for 1-hour NO_2. Since there are very limited NO_2 monitoring sites in Arizona and nearly all monitoring sites are located in the Phoenix/Tucson metropolitan area, ADEQ may allow applicants to use a data set obtained from other states if the data set is believed to be more representative. The applicant should review and compare the topography, climatology, and emissions sources (such as vehicle emissions and industrial sources) between the area of the proposed project and the area where the selected monitor is located. ADEQ is planning to operate a NO_2 monitor in Alamo Lake, which will help estimate the background concentrations for some remote areas in future.

The applicant may use a uniform monitored background concentration or hour-of-day monitored background concentrations in the modeling compliance demonstration for the 1-hour NO_2 NAAQS.

Using a uniform monitored background concentration. The 98th percentile of the annual distribution of daily maximum 1-hour values averaged across the most recent three years of monitored data should be used for determining the background concentration for 1-hour NO_2.

Using hour-of-day monitored background concentrations. ADEQ recommends using **t**he following three refined background datasets:

- <u>98th percentile of the Monthly Hour-Of-Day (1st Highest)</u>: For each of the three years under review, Monthly Hour-Of-Day is determined by organizing all of the NO_2 concentrations by hour of day (1AM, 2AM, 3AM, etc) for each month in descending order and selecting the 1st highest NO_2 concentrations for each hour of the day. The background concentrations are then determined as the 3 year average of the 1st highest concentrations for each hour of the day and month.

- <u>98th percentile of the Seasonal Hour-Of-Day (3rd Highest):</u> For each of the three years under review, Seasonal Hour-Of-Day is determined by organizing all of the NO_2 concentrations by hour of day (1AM, 2AM, 3AM, etc) for each season of the year in descending order and selecting the 3rd highest NO_2 concentrations for each hour of the day. The background concentrations are then determined as the 3 year average of the 3rd highest concentrations for each hour of the day and season.

- <u>98th percentile of The Annual Hour-Of-Day (8th Highest):</u> For each of the three years under review, Annual Hour-of-Day is determined by organizing all of the NO_2 concentrations by hour of day (1AM, 2AM, 3AM, etc) in descending order and selecting the 8th highest NO_2 concentration for each hour of the day. The background concentrations are then determined as the 3 year average of the 8th highest concentrations for each hour of the day.

It should be noted that the approaches presented above are not an exhaustive list of approaches that are acceptable to ADEQ. Please consult with ADEQ if other refined methods are used.

Current on-line sources for 1-hour NO_2 are listed as follows:

- EPA AirData: 1-hour values (first, second, 98th percentile); in most cases, monitoring occurs in high population areas http://www.epa.gov/airdata/

- EPA Air Quality System (AQS) raw data: EPA provides hourly data sets in raw format that can be downloaded at
  http://www.epa.gov/ttn/airs/airsaqs/detaildata/downloadaqsdata.htm

Background Concentration for Ozone

Background ambient ozone (O_3) concentrations are required for the applications of the OLM and PVMRM options in AERMOD. Ozone concentrations can be entered into the model as a single (most conservative) value or hourly datasets.

Using a single value. To be defensible, the highest hourly ozone concentration over the modeled period should be used. The default value of 40 ppb in AERMOD or annual average ozone concentrations should not be used. The highest hourly ozone concentrations are available at EPA AirData:
http://www.epa.gov/airdata/

Using hourly data sets. Current on-line sources for 1-hour O_3 are listed as follows:

- EPA Air Quality System (AQS) raw data: EPA provides hourly data sets in raw format that can be downloaded at
  http://www.epa.gov/ttn/airs/airsaqs/detaildata/downloadaqsdata.htm

- Clean Air Status and Trends Network (CASTNET): Hourly datasets are available for three remote areas, including Chiricahua National Monument, Grand Canyon National Park, and Petrified National Park.
  http://epa.gov/castnet/javaweb/index.html

Gap filling for missing ozone. For a single missing hour, use linear interpolations to fill in the missing concentrations based on the previous and subsequent hour concentrations or simply use the higher one. For multiple missing hours, it is recommended to use the following approaches to fill in gaps:

- Use the highest hourly ozone concentration over the modeled period without any additional justifications;
- Determine the maximum hourly ozone concentration for each season and use the seasonally maximum concentration to substitute for any missing data within that season;
- Determine the maximum hourly ozone concentration for each month and use the monthly maximum concentration to substitute for any missing data within that month; and
- For each month, calculate the maximum ozone concentration for each diurnal hour and use these hourly maximum concentrations to fill in their corresponding missing diurnal hours.

It should be noted that the approaches presented above are not an exhaustive list of procedures that are acceptable to ADEQ. Please consult with ADEQ if other refined methods or procedures are used.

7.1.5 In-Stack NO_2/NO_X Ratio

The NO_2/NOx in-stack ratio is critical since it defines the portion of the model predicted NOx concentration that will be automatically converted to NO_2. The remaining portion released into the air may or may not undergo conversion to NO_2 prior to it reaching a receptor point. In the case of lower-level releases, the transport distance may be a few hundred meters or less. In this case, the predicted concentration would be in-stack ratio dependent with minimal NO_2 formation due to reactions with O_3. Hence, the user's choice of an in-stack ratio could be the determining factor in model predictions.

Prior to the new 1-hour NO_2 NAAQS, a commonly used in-stack ratio for purposes of modeling the annual average NO_2 impact was 0.10. Currently, limited information is available on in-stack NO_2/NOx ratios for 1-hour NO_2 nationwide. EPA has started collecting in-stack NO_2/NOx data for varied source categories, if available. However, it is unclear how long it will take EPA to compile and develop appropriate in-stack ratios for specific sources. During the transition period, it is suggested to use the following hierarchy in-stack ratio data sources:

- Source testing data reviewed and verified by a local air district, state, and/or EPA (ADEQ may have some testing data available for Arizona sources, so please contact with ADEQ if interested);

- If a source-specific testing ratio is absent, use the data for a similar source reported in the literatures; the applicant should provide detailed data analysis and literature review to justify the in-stack ratio being selected; and

- If both (i) and (ii) data are absent, use an in-stack ratio of 0.5 without justifications as per EPA's clarification memo dated March 1, 2011 (U.S. EPA, 2011d).

7.1.6 Treatment of Intermittent Sources

Intermittent emission sources may present challenges for demonstrating compliance with 1-hour NO_2 NAAQS assuming continuous operation. On March 1, 2011, EPA provided additional guidance that specifically addressed the issues of intermittent emissions (U.S. EPA, 2011d). The guidance recommends that compliance demonstrations for the 1-hour NO_2 NAAQS should be based on "emission scenarios that can logically be assumed to be relatively continuous or which occur frequently enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations." In part, the guidance allows the reviewing agency, at their discretion, to exempt intermittent units from model requirements under appropriate circumstances. However, the guidance does not discuss how to determine whether the source is "continuous enough" or "frequent enough". Moreover, the guidance does not provide detailed interpretation about "significant contribution" to the annual distribution.

At this stage, ADEQ may allow an exemption from 1-hour NO_2 modeling for the following circumstances:

- Any intermittent units that operate no more than 200 hours per year;
- Blasting sources that are limited to 24 blasts per year;
- Emergency generators that operate up to 500 hours per year and no more than 100 hours per year for maintenance and readiness testing purposes;
- Infrequent startup/shutdown operations.

Given the complexity of operation scenarios for intermittent emission sources, please consult with ADEQ to determine whether the proposed intermittent sources are exempted from 1-hour NO_2 modeling or not. The applicant should provide ADEQ the following information: number and size of emission units; frequency and duration; allowed fuels, sulfur and nitrogen content; short-term peak emission rates vs. emissions rates during steady-state operations (if applicable); concurrency with other intermittent sources (if applicable); Location of engines with regard to the ambient air boundary of the facility; and etc.

The following approaches are recommended to model 1-hour NO_2 for intermittent emissions:

- If the operation is restricted to specific time periods (for example, certain hours of the day), model maximum hourly emission rates for these specific time periods by defining Emission Rate Flag with EMISFACT keyword in AERMOD;
- In cases where the frequency of intermittent emissions is uncertain, assume continuous operation and model impacts based on annualized hourly emission rate rather than the maximum hourly emission rate. For example, if a proposed permit includes a limit of 500 hours/year or less for an intermittent source, a modeling analysis could be based on assuming continuous operation at the average hourly rate, i.e., the maximum hourly rate times 500/8760.

7.1.7 Modeling Demonstration with the 1-hour NO_2 NAAQS

In general, the guidance in Section 5 and Section 6 should be followed for non-PSD sources and PSD sources, respectively. For PSD sources, ADEQ may allow applicants to use a 10 km radius of background sources in the modeled emission inventory, if sufficient justification is provided.

Based on the form of the 1-hour NO_2 NAAQS, the design value should be calculated as the average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations averaged across the modeled years. As previously discussed, either a uniform monitored background concentration or Monthly/Seasonal/Annual hour-of-day monitored background concentrations may be used.

If a uniform monitored background concentration is used, the following steps should be followed to calculate a design value to compare against the standard:

- At each receptor, for each hour of the modeled period, calculate a modeled concentration;
- From the concentrations calculated in step 1, obtain the 1-hour maximum concentration at each receptor for each modeled day (365 or 366 values per receptor per year);
- From the output of step 2, for each year modeled, calculate the 98th percentile (8th highest) daily maximum 1-hour concentration at each receptor (if modeling 5 years of meteorological data, this results in five 98th percentile concentrations at each receptor);
- Average the 98th percentile (or 8th highest) concentrations across the modeled years to obtain a design value at each receptor;
- The highest of the average 8th-highest (98th percentile) concentrations across all receptors represents the modeled 1-hour NO_2 design value;
- The modeled design value from step 5 is added to the 3-year average of the 98th percentile of the daily 1-hour maximum monitored concentration. The sum is then compared to the 1-hour NO_2 NAAQS.

Note that the first 5 steps above can be executed by AERMOD Version 11059 or newer by simply setting POLLUTID to NO_2 and the RECTABLE to the 8th highest value.

If Monthly/Seasonal/Annual hour-of-day monitored background concentrations are used, the following steps should be followed to calculate a design value to compare against the standard:

- Use the updated version of AERMOD (11059 or newer);
- Use the BACKGRND keyword on the SO pathway to input temporally varying background concentrations; the total number of inputs for Monthly/Seasonal/Annual hour-of-day monitored background concentrations are 288 (12×24), 96 (4×24), and 24, respectively;
- Set the RECTABLE to the 8th Highest Value;
- Set POLLUTID to NO_2;
- AERMOD will process each of the modeled years and determine the design value which includes the NO_2 background concentrations entered. The design value is then compared to the 1-hour NO_2 NAAQS.

If a NAAQS violation is projected, then it is necessary to conduct a source contribution analysis. Starting AERMOD Version 11059, a MAXDCONT option allows users to determine whether a source or a group of sources contributes significantly to modeled violations of the NAAQS, paired in time and space.

7.2 Modeling for 1-hour SO_2

On June 2, 2010, EPA established a new 1-hour National Ambient Air Quality Standard (NAAQS) for sulfur dioxide (SO_2) of 75 parts per billion (ppb) (approximately 196 $\mu g/m^3$). The new 1-hour standard is calculated as the three-year average of the 99th percentile of daily maximum one-hour average concentrations of SO_2. To demonstrate compliance with EPA's new 1-hour SO_2 NAAQS, air quality dispersion modeling analysis must be performed to show that emissions from a source will not cause or contribute to a violation of the standard. Since the 1-hour SO_2 standard is much more stringent than the previous NAAQS, it has been found that demonstrating compliance with the new standard is significantly challenging, particularly for short stacks and small facility footprints (AIWG Workgroup, 2012).

To assist sources and permitting authorities in carrying out the required air quality analysis for 1-hour SO_2 compliance demonstrations, EPA has issued two guidance memorandums:

- Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard (U.S. EPA, 2010b);

- Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard (U.S. EPA, 2011d). *Although this guidance is for NO_2 permit modeling, the common 1 hour averaging time and form of both the NO_2 and SO_2 standards makes this modeling guidance applicable to the 1-hour SO_2 NAAQS.*

While the two memorandums are specifically for major sources and major modifications that are subject to Prevention of Significant Deterioration (PSD) requirements, ADEQ believes that some principles and guidance can apply to minor sources, in part, to ensure consistency of treatment in permitting and to ensure that it is not imposing different requirements on minor sources than those to which PSD sources are subject.

The following guidance describes ADEQ's requirements and recommended procedures for 1-hour SO_2 permit modeling. Due to the technical issues associated with 1-hour SO_2 modeling, the guidance will be amended periodically to incorporate new modeling guidance developed by EPA.

7.2.1 Emission Rate

For sources modeled to determine compliance with the 1-hour SO_2 NAAQS, the maximum 1-hour emission rates must be used unless otherwise discussed or otherwise approved by ADEQ. For example, an emission rate lower than the maximum 1-hour rate may be used if it will be enforceable through a permit condition. For modeling some intermittent sources with an uncertain operating frequency, ADEQ may also allow using an annualized hourly emission rate rather than the maximum hourly emission rate (see Section 7.1.6). For existing sources, the existing SO_2 emission inventories used to support modeling for compliance with the 3-hour and 24-hour SO_2 standards should serve as a useful starting point, and may be adequate in many cases for use in assessing compliance with the new 1-hour SO_2 standard.

7.2.2 Significant Impact Level

The EPA's interim significant impact level (SIL) (3 ppb, 7.8 $\mu g/m^3$) for 1-hour SO_2 should be used unless EPA promulgates an official 1-hour SO_2 SIL. To determine whether a cumulative impact assessment is needed for PSD sources, the interim SIL should be compared to the highest of the 5-year average of the maximum modeled 1-hour SO_2 concentrations predicted at each receptor (if multiyear meteorological data are used) or the highest modeled 1-hour SO_2 concentration (if one-year meteorological data are used.

7.2.3 Determining Background Concentrations

The applicant may use a uniform monitored background concentration or hour-of-day monitored background concentrations in the modeling compliance demonstration for the 1-hour SO_2 NAAQS.

Using a uniform monitored background concentration. The 99th percentile of the annual distribution of daily maximum 1-hours values averaged across the most recent three years of monitored data should be used for determining the background concentration for 1-hour SO_2.

Using hour-of-day monitored background concentrations. ADEQ recommends using the following three refined background datasets:

- <u>99th percentile of the Monthly Hour-Of-Day (1st Highest)</u>: For each of the three years under review, Monthly Hour-Of-Day is determined by organizing all of the SO_2 concentrations by hour of day (1AM, 2AM, 3AM, etc) for each month in descending order and selecting the 1st highest SO_2 concentrations for each hour of the day. The background concentrations are then determined as the 3 year average of the 1st highest concentrations for each hour of the day and month.

- <u>99th percentile of the Seasonal Hour-Of-Day (2nd Highest):</u> For each of the three years under review, Seasonal Hour-Of-Day is determined by organizing all of the SO_2 concentrations by hour of day (1AM, 2AM, 3AM, etc) for each season of the year in descending order and selecting the 2nd highest SO_2 concentrations for each hour of the day. The background concentrations are then determined as the 3 year average of the 2rd highest concentrations for each hour of the day and season.

- 99th percentile of The Annual Hour-Of-Day (4th Highest): For each of the three years under review, Annual Hour-of-Day is determined by organizing all of the SO_2 concentrations by hour of day (1AM, 2AM, 3AM, etc) in descending order and selecting the 4th highest SO_2 concentration for each hour of the day. The background concentrations are then determined as the 3 year average of the 4th highest concentrations for each hour of the day.

It should be noted that the approaches presented above are not an exhaustive list of approaches that are acceptable to ADEQ. Please consult with ADEQ if other refined methods are used.

Current on-line sources for 1-hour SO_2 are listed as follows:

- EPA AirData: 1-hour values (first, second, 99th percentile); in most cases, monitoring occurs in high population areas
  http://www.epa.gov/airdata/

- EPA Air Quality System (AQS) raw data: EPA provides hourly data sets in raw format that can be downloaded at
  http://www.epa.gov/ttn/airs/airsaqs/detaildata/downloadaqsdata.htm

7.2.4 Treatment of Intermittent Sources

Use the same guidance for 1-hour NO_2 (See Section 7.1.6).

7.2.5 Modeling Demonstration with the 1-hour SO_2 NAAQS

In general, the guidance in Section 5 and Section 6 should be followed for non-PSD sources and PSD sources, respectively. For PSD sources, ADEQ may allow the applicant to use a 10 km radius of background sources in the modeled emission inventory, if sufficient justification is provided.

Based on the form of the 1-hour SO_2 NAAQS, the design value should be calculated as the average of the 99th percentile of the annual distribution of daily maximum 1-hour concentrations averaged across the modeled years. As previously discussed, either a uniform monitored background concentration or Monthly/Seasonal/Annual hour-of-day monitored background concentrations may be used.

If a uniform monitored background concentration is used, the following steps should be followed to calculate a design value to compare against the standard:

- At each receptor, for each hour of the modeled period, calculate a modeled concentration;

- From the concentrations calculated in step 1, obtain the 1-hour maximum concentration at each receptor for each modeled day (365 or 366 values per receptor per year);
- From the output of step 2, for each year modeled, calculate the 99th percentile (4th highest) daily maximum 1-hour concentration at each receptor (if modeling 5 years of meteorological data, this results in five 99th percentile concentrations at each receptor);
- Average the 99th percentile (or 4th highest) concentrations across the modeled years to obtain a design value at each receptor;
- The highest of the average 4th-highest (99th percentile) concentrations across all receptors represents the modeled 1-hour SO_2 design value;
- The modeled design value from step 5 is added to the 3-year average of the 99th percentile of the daily 1-hour maximum monitored concentration. The sum is then compared to the 1-hour SO_2 NAAQS.

Note that the first 5 steps above can be executed by AERMOD Version 11059 or newer by simply setting POLLUTID to SO_2 and the RECTABLE to the 4th highest value.

If Monthly/Seasonal/Annual hour-of-day monitored background concentrations are used, the following steps should be followed to calculate a design value to compare against the standard:

- Use the updated version of AERMOD (11059 or newer);
- Use the BACKGRND keyword on the SO pathway to input temporally varying background concentrations; the total number of inputs for Monthly/Seasonal/Annual hour-of-day monitored background concentrations are 288 (12×24), 96 (4×24), and 24, respectively;
- Set the RECTABLE to the 4th Highest Value;
- Set POLLUTID to SO_2;
- AERMOD will process each of the modeled years and determine the design value which includes the SO_2 background concentrations entered. The design value is then compared to the 1-hour SO_2 NAAQS.

If a NAAQS violation is projected, then it is necessary to conduct a source contribution analysis. Starting AERMOD Version 11059, a MAXDCONT option allows users to determine whether a source or a group of sources contributes significantly to modeled violations of the NAAQS, paired in time and space.

7.3 Modeling for $PM_{2.5}$

The national ambient air quality standards (NAAQS) for particular matter less than 2.5 micrometers ($PM_{2.5}$) have been revised by the EPA since 2006. Effective December 15, 2006, the EPA increased the stringency of the $PM_{2.5}$ standard by lowering the previous 24 hour standard of 65 μg/m^3 to 35 μg/m^3. On December 14, 2012, the EPA further strengthened the $PM_{2.5}$ standard by lowering the previous annual standard of 15 μg/m^3 to 12 μg/m^3.

To help states implement the revised standards, the EPA has issued a number of rules related to permitting requirements. On May 16, 2008, EPA finalized the rule for governing the implementation of the NSR program for $PM_{2.5}$. This rule, effective July 15, 2008, established the significant emission rate (SER) for $PM_{2.5}$ and for the $PM_{2.5}$ precursors which define the rates at which a net emissions increase will trigger major NSR permitting requirements. This rule also included a "grandfathering provision" that allowed applicants for federal PSD permits to continue relying upon the PM_{10} Surrogate Policy. On February 11, 2010, EPA published a proposal to repeal the grandfathering provision and an early end to the PM_{10} Surrogate Policy which occurred in May 2011.

To assist sources and permitting authorities in carrying out the required air quality analysis for $PM_{2.5}$ compliance demonstrations, a guidance memorandum entitled "Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS" was released on March 23, 2010 (U.S. EPA, 2010c). In spring 2010, the National Association of Clean Air Agencies (NACAA) $PM_{2.5}$ Modeling Implementation Workgroup was formed at the request of EPA to provide technical recommendations to the agency to aid in further development of $PM_{2.5}$ permit modeling guidance. A final report from the NACAA $PM_{2.5}$ Workgroup was released on January 7, 2011 (NACAA, 2011). On March 4, 2013, EPA released the Draft Guidance for $PM_{2.5}$ Permit Modeling to the public for consideration, review, and comment (U.S. EPA, 2013b).

The following guidance describes ADEQ's requirements and recommended procedures for $PM_{2.5}$ permit modeling. Note that a demonstration of compliance with the PM_{10} NAAQS will no longer serve as a surrogate for compliance with the $PM_{2.5}$ NAAQS. Instead, the applicant must consider $PM_{2.5}$ as a criteria pollutant and address it in preparing an application. The guidance will be amended based on the EPA's final Guidance for $PM_{2.5}$ Permit Modeling.

7.3.1 Significant Monitoring Concentration and Significant Impact Levels

The EPA promulgated significant monitoring concentrations (SMC) and significant impact levels (SILs) for $PM_{2.5}$ in 2010. However, on January 22, 2013, the U.S. Court of Appeals for the District of Columbia Circuit vacated the SMC for $PM_{2.5}$ and two provisions in EPA's PSD regulations containing SILs for $PM_{2.5}$.

Due to the court decision, the applicant should not use the SMC for $PM_{2.5}$ to determine whether preconstruction monitoring is required or not. However, the applicant may continue to meet the preconstruction monitoring requirements by using the existing representative air quality data with adequate justification and documentation.

As the court decision does not preclude the use of SILs for $PM_{2.5}$, the SILs for $PM_{2.5}$ may still be applied to support a PSD permitting, provided they are used in a manner that is consistent with the requirements of Section 165(a)(3) of the CAA. To use SILs as a screening tool in a significant impact analysis, the applicant should determine whether a substantial portion of the NAAQS has already been consumed by evaluating background concentrations against the respective $PM_{2.5}$ NAAQS. Background concentrations are determined based on preconstruction monitoring data or adequately representative monitoring data from an existing monitoring network. If the source impact is below the applicable SIL AND the difference between the NAAQS and the measured $PM_{2.5}$ background in the area is greater than the SIL, it is believed that the source will not cause a new NAAQS violation and a full (cumulative) impact analysis can be exempted. However, if the difference between the NAAQS and the measured $PM_{2.5}$ background in the area is equal to or lower than the applicable SIL, a full (cumulative) impact analysis must be conducted, regardless of whether the SIL is exceeded or not.

7.3.2 Modeling Primary $PM_{2.5}$ and Secondarily Formed $PM_{2.5}$

For any $PM_{2.5}$ sources, impacts from the primary $PM_{2.5}$ emissions must be modeled. Moreover, given the importance of $PM_{2.5}$ secondary components (e.g., ammonium sulfate, ammonium nitrate, and secondary organic aerosols), impacts of precursor emissions from a project source must be taken into account if the source emits more than 40 tons per year of SO_2 or NOx. If the source emits more than 40 tons per year of SO_2 (or NOx) and less than 40 tons per year of NOx (or SO_2), the emission impacts from both pollutants should be considered.

There are technical complications associated with the ability of AERMOD to estimate the impacts of secondarily formed $PM_{2.5}$. For assessing the impacts of precursor emission on secondary $PM_{2.5}$ formation, the following approaches are recommended (U.S.EPA, 2013b):

- a qualitative assessment,
- a hybrid of qualitative and quantitative assessments utilizing existing technical work, and
- a full quantitative photochemical grid modeling exercise.

<u>Qualitative Assessment</u>

An appropriate conceptual description of $PM_{2.5}$ is essential for a qualitative assessment. The description may include but is not limited to the following components:

Characterization of current $PM_{2.5}$ concentrations. This characterization should examine the regional background $PM_{2.5}$ concentrations and their seasonality and particular component species (e.g. sulfates, nitrates, and elemental or organic carbons). It is also important to describe typical background concentrations of certain chemical species necessary for the photochemical reactions to form secondary $PM_{2.5}$, such as NH_3, VOC and ozone. The limitations of these species may limit the formation of secondary $PM_{2.5}$.

Characterization of meteorological conditions. This characterization should examine the regional meteorological conditions that could limit or enhance the formation of secondary $PM_{2.5}$. It is important to identify the meteorological conditions that could result in higher ambient $PM_{2.5}$ concentrations.

Characterization of spatial and temporal correlation of the primary and secondary $PM_{2.5}$ impacts. This characterization should examine whether the maximum primary $PM_{2.5}$ impacts and the maximum secondary $PM_{2.5}$ impacts from the source will occur at the same time (paired in time) or location (paired in space). If they are unlikely to be paired in time or space, the modeling demonstrations of compliance with the NAAQS would be strengthened.

As each compliance demonstration is unique, the applicant should consider multiple factors specific to their particular case. An example of a qualitative assessment is shown in the EPA's Draft Guidance Appendix C.

Hybrid of Qualitative and Quantitative Assessment

For some modeling demonstrations, it is necessary to provide some quantification of the potential secondary $PM_{2.5}$ impacts from the proposed project's precursor emissions. Unfortunately, there is no robust technique for quantitative assessment so far. During the transition period, it is suggested to use the "offset ratios" approach established by the NACAA $PM_{2.5}$ Workgroup to address the secondary formation from a project source (NACAA, 2011). The secondarily formed $PM_{2.5}$ is estimated by applying interpollutant "offset ratios", as defined in EPA's NSR implementation rule for $PM_{2.5}$ (73 FR 28321, 2008):

Nationwide SO_2 to Primary $PM_{2.5}$ offset ratio: 40:1
Western U.S. NOx to Primary $PM_{2.5}$ offset ratio: 100:1

The total equivalent primary $PM_{2.5}$ emissions can be estimated:

$$\text{Total Equivalent Primary } PM_{2.5} \text{ [TPY]} \\ = \text{Primary } PM_{2.5} \text{ [TPY]} + SO_2 \text{ [TPY]}/40 + NO_X \text{ [TPY]}/100$$

The total impact from Primary $PM_{2.5}$ and Secondarily Formed $PM_{2.5}$ can be estimated by multiplying the modeled concentration for primary $PM_{2.5}$ by the emission ratio:

$$\text{Total } PM_{2.5}\ (\mu g/m^3) = \\ = \text{Primary } PM_{2.5}\ (\mu g/m^3) \times \\ \{(\text{total equivalent primary } PM_{2.5} \text{ [TPY]})/(\text{Primary } PM_{2.5} \text{ [TPY]})\}$$

It should be addressed that, the nationwide or Western offset ratios above are used for simplifying the quantitative assessment only. Ideally, the offset ratios should be specific to the source and area of concern. In the future, ADEQ may work with the EPA Region 9 office and other state/local air permitting agencies to develop appropriate offset ratios for the purposes of estimating potential secondary $PM_{2.5}$ impacts. In the absence of information showing that the site varies materially from the general condition, use of the offset approach above will be acceptable.

Full Quantitative Photochemical Grid Modeling

It is anticipated that this case may be rare, especially in light of compliance requirements of the new 1-hour NO_2 and SO_2 NAAQS. Please consult with ADEQ if a full quantitative photochemical grid modeling analysis is proposed.

7.3.3 Emission Inventories

The EPA's document titled, "Draft – Background for 24-hour $PM_{2.5}$ NAAQS: How to Construct Model Emission Inventory for Permit Modeling", lists the following hierarchy for emission data sources (U.S.EPA, 2011e):

- Source test data from facility or similar sources;
- Vendor supplied emission factor data; and
- AP-42 Emission Factor Data

To develop a reliable emission inventory, high quality emission factor data of I and II are desirable. However, if the I and II data are not available or the quality of the data is questionable, the applicant may use the traditional AP-42 emission factor data. Currently the WebFIRE database contains $PM_{2.5}$ emission factors for over 850 processes, most of which are combustion processes (NACAA, 2011). The information is accessible through the internet at: http://cfpub.epa.gov/webfire/

A number of source categories in AP-42 only have emission factor information for filterable PM and PM_{10}. The simplest and most conservative way to estimate direct $PM_{2.5}$ emissions is to assume $PM_{2.5}$ emissions are equal to PM_{10} emissions. Emissions estimates may be further refined by using the ratios of $PM_{2.5}$ and PM_{10} emissions from similar sources. ADEQ accepts the following particle size-fraction databases to calculate $PM_{2.5}$ from PM_{10} data:

- Appendix B.1 and Appendix B.2 of AP-42
  http://www.epa.gov/ttnchie1/ap42/

- Speciation profiles from the California Air Resource Board (CARB)
  http://arb.ca.gov/ei/speciate/speciate.htm

Caution should be taken when selecting and comparing emission factors as they are based on industry source type and control equipment. In particular, before using a $PM_{2.5}$ /PM_{10} ratio to calculate $PM_{2.5}$ emissions, the applicant must verify whether the ratio is for a controlled source or for an uncontrolled source. It is not appropriate, for example, to derive controlled $PM_{2.5}$ emissions from controlled PM_{10} emissions based on an uncontrolled $PM_{2.5}$ / PM_{10} ratio.

7.3.4 Background Concentration

In general, the guidance in Section 3.10 should be followed when determining background concentrations for $PM_{2.5}$. Special considerations should be taken to ensure that the background concentrations account for secondary $PM_{2.5}$ impacts from regional transport and precursor emissions from existing sources represented in the modeling domain.

The ADEQ's existing ambient $PM_{2.5}$ monitoring network as well as Interagency Monitoring of Protected Visual Environments (IMPROVE) sites may be used to estimate background $PM_{2.5}$ levels for locations in Arizona. The annual background of $PM_{2.5}$ value should be based on the average of the most recent three years of the annual average $PM_{2.5}$ concentrations. The 24-hour background $PM_{2.5}$ value should be based on the average of the 98th percentile 24-hour values measured over the last three years. A more defined background may be determined by considering seasonal variation in background $PM_{2.5}$ levels. The background on a seasonal basis can be determined as the 98th percentile of monitored concentrations for each season, averaged across three years of monitoring. The applicant may choose to develop the background concentrations by performing site-specific pre-constructing monitoring. ADEQ may allow the applicant to define background values that are less than the observed design values, provided that the applicant provides sound technical reasoning for such an approach.

Regarding the determination of the 98th percentile monitored 24-hour value based on the number of days sampled during the year, please refer to the ambient monitoring regulations, Appendix N to 40 CFR Part 50 (**Table 13**).

Table 13 Calculated 98th Percentile Value Based on the Annual Creditable Number of Samples

annual creditable number of samples	the nth maximum value of the year (98% Percentile Value)
0-50	1
51-100	2
101-150	3
151-200	4
201-250	5
251-300	6
301-350	7
351-366	8

7.3.5 Comparison to the SIL

EPA recommends that the applicable SIL be compared to either of the following, depending on the meteorological data used in the analysis:

- The highest of the 5-year averages of the maximum modeled 24-hour or annual $PM_{2.5}$ concentrations predicted each year at each receptor, based on 5 years of representative National Weather Service (NWS) data; or
- The highest modeled 24-hour or annual $PM_{2.5}$ concentrations predicted across all receptors based on 1 year of site-specific meteorological data, or the highest of the multi-year averages of the maximum modeled 24-hour or annual $PM_{2.5}$ concentrations predicted each year at each receptor, based on 2 or more years, up to 5 complete years of available site-specific meteorological data.

The SIL comparison would be challenging if both primary and secondary $PM_{2.5}$ ambient impacts associated with the proposed source have to be addressed. Due to the complexity in quantifying the secondary $PM_{2.5}$ impacts, the applicant should consult with ADEQ to develop an appropriate approach for combing the modeled primary and secondary $PM_{2.5}$ impacts.

7.3.6 Modeling Demonstration with the $PM_{2.5}$ NAAQS

Please note that for $PM_{2.5}$ NAAQS modeling demonstrations, ADEQ retains flexibility to determine whether a source causes or contributes to a violation where the violation appears attributable to secondary particulate.

Please refer to Section 7.3.2 regarding whether the secondary impacts from the source should be included or not.

- For non-PSD sources, the modeled impacts should include primary and (or) secondary impacts from the proposed new or modified source.
- For PSD sources, the modeled impacts should include primary and (or) secondary impacts from the proposed new or modified source as well as primary impacts from nearby sources in the modeled emission inventory. Please refer to Section 6.2.1 regarding the NAAQS modeling inventory.

Modeling demonstration with the annual NAAQS

The highest of the multi-year averages of the modeled annual averages (5-year NWS data or multiple year site-specific meteorological data), or the highest modeled annual average (1 year site-specific meteorological data) should be added to the monitored annual design value. The resulting concentration is then compared to the annual $PM_{2.5}$ NAAQS of 12 $\mu g/m^3$.

Modeling demonstration with the 24-hour NAAQS

EPA recommends using two-tier procedures for the cumulative impact analysis for 24-hour $PM_{2.5}$:

For a First Tier modeling analysis, the highest of multi-year averages of the 98th percentile of the annual distribution of 24-hour concentrations (5-year NWS data or multiple year site-specific meteorological data), or the highest of the 98th percentile of the annual distribution of 24-hour concentrations (1 year site-specific meteorological data) should be added to the monitored daily design value. The resulting First Tier cumulative daily concentration would then be compared to the daily $PM_{2.5}$ NAAQS of 35 $\mu g/m^3$. If a NAAQS violation is projected, then a source contribution analysis may be considered or a Second Tier modeling analysis may be used.

For applications where impacts from primary $PM_{2.5}$ emissions are not temporally correlated with background $PM_{2.5}$ levels, following the First Tier modeling analysis may be overly conservative. In such cases, combining the monitored and modeled $PM_{2.5}$ concentrations on a seasonal or quarterly basis through a Second Tier modeling analysis might be more appropriate.

For a Second Tier modeling analysis, four seasonal background values would be combined with the modeled concentrations on a seasonal basis. The recommended input for the Second Tier modeling analysis is the 98th percentile of monitored concentrations for each season, averaged across three years of monitoring. For a monitor with a daily, 24-hour sampling frequency, the 98th percentile rank is the 3rd highest 24-hour value for each season. The resulting Second Tier cumulative daily concentration would then be compared to the daily $PM_{2.5}$ NAAQS of 35 $\mu g/m^3$.

For PSD sources, if the cumulative impact assessment results in modeled violations, then the applicant will need to determine whether the project's emissions represent a significant contribution to those modeled violations. Due to the court decision as discussed in Section 7.3.1, please consult with ADEQ before using the SIL value of $PM_{2.5}$ as the basis for concluding that a source with an impact below this value does not significantly contribute to a modeled violation.

7.3.7 Modeling demonstration with the $PM_{2.5}$ Increments

The highest annual concentration over the entire receptor network for each year modeled should be used for compliance with the annual increments. The highest, second-highest 24-hour concentration over the entire receptor network for each year modeled should be used for compliance with the 24-hour increments.

The $PM_{2.5}$ increment analysis includes many of the same elements discussed above for $PM_{2.5}$ NAAQS analysis. However, the increment analysis has some distinguished features:

- Increment compliance is based on the increase in concentrations relative to baseline value due to proposed emissions from the new or modified source, plus impacts due to increment-consuming emissions from other sources within the affected "baseline area".
- Increment compliance is based on the net impact of actual emissions increases and decreases from new and nearby increment-affecting sources, whereas the NAAQS analysis is generally based on the maximum allowable emissions from all nearby sources.
- Emission increases (or decreases) after the "minor source baseline date" may consume (or expand) increment.

7.4 Additional Considerations for Modeling Particulate Matter (PM)

7.4.1 Paired-Sums Approach

Challenging situations (such as high background concentrations) may require detailed considerations of the temporal variability of modeled vs. monitored concentrations. The "paired-sums" approach is the method for combining modeled concentrations with monitored background concentrations on a day-by-day basis. The sums of the paired values are then processed to demonstrate the compliance with the 24-hour standard for PM_{10} or $PM_{2.5}$.

Given prior approval by ADEQ, the applicant may use the "paired-sums" approach to demonstrate the compliance with the 24-hour standard for PM_{10} or $PM_{2.5}$. An underlying assumption for this approach is that the background monitored levels for 24-hour averaging period are spatially uniform and that the monitored values are fully representative (or conservative) of background levels at each receptor for each 24-hour averaging period. Adequate justification and documentation must be presented for selecting representative (or conservative) monitoring site(s). Moreover, each daily monitored data must be used unless the concentration is flagged as an exceptional event. It is not acceptable to exclude high concentrations caused by non-exceptional event processes.

Another significant issue raised for using the "paired-sums" approach is that many locations do not have access to continuous daily observations. For example, FRM (federal reference method) $PM_{2.5}$ data are commonly taken on a schedule of one sample every third day (1-in-3) or one sample every sixth day (1-in-6). In the protocol, the applicant must describe and justify the approaches to fill in the background concentrations for those days when monitoring was not conducted. Note that unless sufficient justifications are provided, ADEQ will not accept the approach by using the higher of the two concentrations measured before and after the day as the background concentrations for those days. This approach is not defensible because it may not capture the dramatic change of $PM_{10}/PM_{2.5}$ levels within the gaps.

7.4.2 Particle Deposition

Based on the guidance provided for application of the AERMOD model in Appendix W, the particle deposition algorithms with a user-specified particle size distribution can be applied under the regulatory default option. The Addendum to the User's Guide For The AMS/EPA Regulatory Model – AERMOD (U.S. EPA-454/B-03-001, 09/2004) explains the particle deposition algorithms and specifies the source parameters for use of particle deposition. All additional data used for an air dispersion analysis that incorporates the particle deposition must be submitted to and approved by ADEQ. In the modeling protocol submitted, the applicant must justify and explain the derivation of particle sizes, percentages/mass fractions, and densities for all particle size distributions used within the model.

7.5 Modeling for Lead (Pb)

The averaging period for the Lead NAAQS is a rolling 3-month average evaluated over a 3-year period. The emissions rate to input into AERMOD should be based on the maximum allowable or permit limit emissions. In certain cases, longer term average emission rates (e.g., monthly average, 3-month average, or 3-month total) or emissions representative of actual operating schedules may be approved for use in modeling demonstrations and corresponding permit limitations. Modeled emission rates, including any proposed limitations on emissions or source operation, should be documented in the modeling protocol, and any associated permit application materials submitted to ADEQ for approval.

AERMOD does not calculate the Lead NAAQS design value. A post-processor called LEADPOST will calculate the Lead NAAQS design values from the AERMOD monthly modeled output. As such, modeling for lead requires that post files be selected from the output pathway in AERMOD. ADEQ recommends that one post file be generated for the Source Group ALL. If five-year meteorological data are used, the five years of model output do not have to be in one AERMOD run. Each individual year can be run separately and the output for each year can be input into LEADPOST. LEADPOST will read the individual files and calculate the design values across the five years provided that each year's runs have the same receptors and source group contributions.

For detailed information regarding the approach to set-up and run LEADPOST, please visit the EPA's SCRAM website at:
http://www.epa.gov/ttn/scram/models/aermod/leadpost.zip

7.6 Modeling for Open Burning/Open Detonation Sources

Given prior approval by ADEQ, the applicant may use OBODM (Open Burn/Open Detonation Model) or AERMOD to simulate open burning and open detonation OB/OD operations.

7.6.1 Modeling OB/OD Operations with OBODM

The OBODM model is listed by EPA as an alternative air quality model, which should be justified for use on a case-by-case basis for individual regulatory applications. The OBODM is intended for use in evaluating the potential air quality impacts of the open burning and detonation (OB/OD) of obsolete munitions and solid propellants. OBODM uses cloud/plume rise dispersion and deposition algorithms taken from existing models for instantaneous and quasi-continuous sources to predict the downwind transport and dispersion of pollutants released by OB/OD operations.

In OBODM, a blast associated with multiple blast holes should be simulated as multiple volume sources, each hole representing a volume source. Since the buoyant rise of a plume from a detonation strongly depends on the quantity of material detonated, treating multiple holes as a single volume source may result in an extremely high plume rise and thus significantly underestimate the ground level impact. An extreme case occurs when the calculated plume height for the imaginary source is far above the top of the surface mixing layer, leading to a zero ground level concentration. This is because OBODM assumes the concentration contribution from the plume material that resides above the top of the surface layer can be neglected.

For multiple sources, each source location in OBODM can be defined separately according to the geographic layout of the blast holes. If the layout information is unavailable, it is suggested to assume that the holes are uniformly distributed within the blasting zone.

7.6.2 Modeling OB/OD Operations with AERMOD

If the applicant proposes to model blasting emissions with AERMOD instead of OBODM, the following issues should be addressed in the modeling protocol:

- As open detonation releases are usually quasi-instantaneous, the methodology for calculating short-term averaging emission rates and annual averaging emission rates for each applicable pollutant should be presented.

- If the blasting emissions are modeled as volume sources, the methodology for calculating the initial dimensions and release heights should be presented. Any underlying assumptions should be explicitly justified.

- If blasting is limited to one blast each day but blasting can occur during any daylight hour, a preliminary analysis should be performed to determine the “highest impact” daylight hour and then use this daily hour to represent the blasting emissions for NAAQS and PSD analyses.

7.7 Modeling for Buoyant Line Sources

For industrial sources where plume rise effects from stationary line sources are important, ADEQ recommends using Buoyant Line and Point Source Dispersion Model (BLP) for the modeling analysis (Schulman and Joseph, 1980). CALPUFF contains the BLP model algorithms imbedded within it while AERMOD does not. If a near-field modeling analysis with AERMOD is performed, the applicant is recommended to consider the following options:

- Use BLP model for buoyant line source and use AERMOD for other sources, and then combine modeled concentrations from BLP and AERMOD spatially and temporally.
- Use BLP model to estimate hourly line source final plume rise and then apply the BLP-predicted final plume heights in AERMOD with hourly volume source approach.

The applicant can also propose other methods with sufficient justification and documentation for ADEQ’s review.

7.8 Modeling for HAPS Sources - Learning Site Policy

ADEQ has established the Learning Site Policy to ensure that children at learning sites are protected from criteria air pollutants as well as hazardous air pollutants (Appendix B). Learning site consists of all existing public schools, charter schools, and private schools at the K-12 level, and all planned sites for schools approved by the Arizona School Facilities Board. If a facility is within 2 miles or less of a learning site, the facility will be subject to the Learning Site Policy. According to the Learning Site Policy, the applicant should submit a modeling analysis to demonstrate the compliance with the NAAQS and Acute/Chronic Ambient Air Concentrations (AAAC and CAAC) for listed air toxics (See Appendix C). ADEQ reserves the right to require a modeling analysis if a facility is expected to result in significant impacts beyond 2 miles of a learning site on a case-by-case basis.

The modeling analysis for HAPs should be conducted with AERSCREEN or AERMOD, following an approach developed with ADEQ. It is suggested that the modeled maximum hourly concentrations are used to compare the acute ambient air concentrations (AAAC) while the modeled annual concentrations are used to compare the chronic ambient air concentrations (CAAC). The NAAQS modeling analysis for learning sites is not required because the compliance with the NAAQS is addressed anywhere else.

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APPENDIX A: MODELING PROTOCOL ELEMENTS

ADEQ recognizes that many air quality specialists have their own preferred formats for protocols. ADEQ does not wish to require permit applicants to use a specific modeling protocol format mandated by ADEQ. Instead, ADEQ has generated a listing of typical protocol elements as an aid in developing a modeling protocol. This listing does not address all possible components of a protocol. Case-by-case judgments should be used to decide if additional aspects of the analysis should be included in the protocol or if certain elements are not necessary in a given situation.

An example modeling protocol outline for a major stationary source subject to PSD is provided below.

Introduction and Project Background Information

- Company and facility name.
- Permit number and type of permit. Check the applicability of the following categories: Class I or Class II; PSD or non-PSD; HAPs or non-HAPs.
- Overview of the project, project location, and general brief description of facility operations.
- Facility and project classification.
- Description of the federal and Arizona regulations and guidelines that pertain to the proposed project. Focus should be on modeling requirements.
- Attainment status classification of all regulated air pollutants for the source location.
- Description of baseline dates and baseline areas (if applicable).

General Regional Characteristics

- Maps and description of local topography, land use of the area surrounding the facility. Also discuss if there are significant human or natural activities that would contribute to background levels.
- Description of regional climatology and meteorology. Focus should be given to discussions of meteorological parameters that most significantly influence the modeling analysis, such as regional and terrain-induced wind patterns.

Detailed Facility Layout

It is essential that the applicant provide ADEQ a detailed facility plot plan and description of the facility. The source must provide a *scaled site plan with a north arrow* indicated that contains the following information:

- Locations of emission points (i.e. smokestacks, vents, etc.) at the facility. Clearly label all emission points that will be modeled. Emission point names should be traceable to a table that contains other required modeling information such as stack parameters and emission rates (see example in Appendix D).
- Location of process equipment (i.e. storage tanks, silos, conveyors, etc.), lay down areas, parking lots, haul roads, maintenance roads, storage piles, etc.
- Location of all buildings at the facility. In addition, the applicant must indicate the height of each building (for single tiered buildings) and/or the height of each building tier (for multi-tiered buildings) on a site plan. If a site plan becomes too crowded, a table listing all this information can be provided instead, with the building ID traceable on the plot.
- Location of the facility's fence line and process area boundaries
- Location and name of any roads and/or properties adjacent to the facility (if applicable).
- Location of nearest residences, schools, and offsite workplaces.

Emission Profiles

- Identify all emission units included in the modeling analysis and make them traceable to a facility site plan.
- Provide brief but sufficient description of emission generation processes for each source (or source category).
- If multiple emission scenarios are involved, evaluate each scenario, provide assumptions, conditions and methodologies for emission evaluation.
- Identify maximum potential short-term emission rates for all modeled pollutants in lb/hr (or lb/day) and g/sec. The maximum short-term emission rate for each source should be used to demonstrate compliance with all short-term averaging standards and guidelines. It is important that the applicant provide emissions information for all averaging times to be considered in the modeling analysis. Potential short-term emission "spikes" from highly fluctuating short-term emissions sources (such as some types of kilns) also need to be characterized and considered in the modeling analysis.
- Identify maximum potential long-term emission rates for all modeled pollutants in ton/yr and in g/sec.
- Identify hr/day and hr/yr operational limits assumed for each source.

Loads Analysis

A loads analysis is required for equipment that may operate under a variety of conditions that could affect emission rates and dispersion characteristics. A loads analysis is a preliminary modeling exercise in which combinations of parameters (e.g. ambient temperature, source loads, relative humidity, etc.) are analyzed to determine which combination leads to the highest modeled impact. For example, turbines should be evaluated at varying loads and temperatures to determine the worst-case modeled impact.

Stack Parameters

- Describe how each modeled source is characterized (i.e. point source, area source, volume source, etc.). For stacks, indicate if the stack is oriented vertically/horizontally and if a fixed rain cap is present.
- List assumed stack parameters and make this information traceable to a facility site plan and emission inventory table.

Modeling Approach

- Description of model selection.
- Description of model inputs/defaults and modeling methods proposed.
- Pollutants and sources considered.
- Methodology of determining source configuration.
    - Volume Source: Explain how the initial lateral and vertical dimension and release height were determined.
    - Point Source: Explain how the stack exit velocity is derived. For a stack that multiple sources emit through, provide parameters used to derive the overall stack parameters, especially exit velocity and exit temperature.
    - Line Source: Explain the source type and the configuration of the contributing individual sources.
    - Other Type of Source: Provide a brief description of how the source configuration was determined.
- Land use classification analysis.
- Description of the process area boundary.
- Proposed process area boundary and receptor grid configurations.
- Identification of the coordinate system and datum used to plot the receptors.
- Discussion regarding the meteorological data proposed.
- Justification for the use of meteorological data if the meteorological data is not based on site-specific data.
- Good Engineering Practice (GEP) stack height analysis.
- Justification of the background air quality monitoring data to be used.
- Include a description of terrain elevation data (types) used and how the elevation data was used to assign terrain elevation and hill height scales.

Off-site Impacts

- Document if and how off-site facilities were addressed in the analysis.
- Discuss whether any off-site sources were eliminated from the analysis.

Special Modeling Considerations

- For PSD sources, describe the approach for addressing visibility, Class I Area modeling, effects on soils and vegetation, growth analysis, characterization of fugitive emissions, etc.
- Address any case-by-case modeling requirements raised by ADEQ (if applicable).

References

- Reference for any method used in the modeling analysis should be clearly sited. A copy of the reference should be provided to ADEQ if requested.

APPENDIX B: LEARNING SITES POLICY IMPLEMENTATION PLAN

ADEQ Arizona Department of Environmental Quality

Memorandum

Date: December 4, 2012
To Eric C. Massey, Director, AQD
Through: Trevor Baggiore, Deputy Director, AQD
Through: Balaji Vaidyanathan, Section Manager, Air Quality Permits Section
From: Naveen Savarirayan, EES, NSRU, Air Quality Permits Section
Subject: Air Quality Division Learning Sites Policy Implementation Plan

APPLICABILITY

This memo outlines the implementation of the ADEQ Policy 1103.0, Environmental Permits and Approvals near Learning Sites (Learning Sites Policy) for the Air Quality Permits Section. The policy is applicable to licensing decisions made by the Air Quality Division Director. This policy supersedes and replaces the policy dated April 12, 2007.

Licensing Decisions Subject to Policy

Upon review of the different classes and types of air quality permits that are issued, it has been determined that the Learning Sites Policy applies to the following licensing decisions:

- ADEQ reserves the right to investigate any licensing decision on a case by case basis if needed.
- Class I Permits
  - All Prevention of Significant Deterioration Determinations
  - All New Source Review Determinations
  - All other types of new major source permits
  - All permit revisions that increase the potential to emit pollutants greater than the permitting exemption threshold
- Class II Permits
  - All new minor source and synthetic minor source permits
  - All permit revisions that increase the potential to emit pollutants greater than the permitting exemption threshold
- General Permit Development
- Dangerous Burn Permits

Class I and Class II Permits

Permit renewals without any associated modifications are exempt from the learning sites policy on the basis that they are existing facilities which have no new emissions and will be addressed as part of any future modification which results in an emissions increase greater than the permitting exemption threshold. Administrative amendments, and permit transfers only involve changes due to a change in ownership status or for the correction of typographical errors. Facility changes without a revision may result in minimal emissions increases and as a result, the

Department has determined that such changes do not need to be evaluated under the learning sites policy.

Open Burn Permits

The Department's open burn permits contain a variety of emission reduction techniques designed to minimize emissions and limit public exposure. Applicants are required to conduct all open burning under atmospheric conditions where public health or safety will not be adversely affected. Permitting staff will conduct outreach with applicants, as needed, to limit the impact of burning activities near learning sites.

General Permits

For sources applying for coverage under a general permit, the learning sites evaluation is not necessary since the development of the permit is associated with emissions from worst-case facility configurations and those emissions are modeled to ensure compliance with all relevant ambient air standards regardless of location.

METHODOLOGY FOR COMPLIANCE

The following procedures are applicable for any air quality permit applications subject to the policy:

- Use the Global Information System (GIS) on ADEQ's Web site to map the location of the applicant's facility (http://gisweb.azdeq.gov/website/impactmap/epanls/):
  - Identify and create a map displaying Learning Sites within 2 miles; or
  - Identify and create maps displaying additional Learning Sites at longer distances if the facility's plume is expected to result in significant impacts beyond 2 miles.
- If no learning sites are within 2 miles of the facility, note such information in the Technical Support Document that accompanies the permit.
- If a facility is within 2 miles or less of a learning site and subject to the learning sites policy:
  - The applicant shall submit a modeling analysis in accordance with the Department's Modeling Guidelines. The results of the modeling must be compared against the National Ambient Air Quality Standards (NAAAQS) and Ambient Air Concentrations for listed air toxics. Facility modifications necessary for the facility to comply with the NAAQS and Ambient Air Concentrations will be reflected in applicable permit conditions.
  - Modeling analysis showing compliance at learning sites will be presented in the technical support document.
  - Evacuation Plan:
    - Facilities which store hazardous pollutants identified under Arizona Revised Statues § 26-346 must register under www.AZserc.org under the Arizona Tier 2 Chemical Inventory Reporting database. If determined by the Department, based upon a facility's application, that it stores applicable hazardous chemicals, the Department will contact the facility to ascertain its registration

status under AZSERC and the possible need for a Facility Emergency Response Plan.

- Transportation Routes:
  - If determined by the Department, based upon a facility's application, that a facility will store or transport hazardous or radioactive materials to or from their location, the facility will be asked to consider alternate transportation routes in order to effectively minimize transportation near learning sites. The Department will consult with facility personnel, as necessary to address potential transportation route concerns.

- The Department will work with applicants to voluntarily reduce predicted impacts as necessary. The Department will also document all information, decisions, and mitigation measures developed and voluntarily implemented, in the technical support document that accompanies the permit. As necessary, such conditions will be included in the permit.

APPENDIX C: ACUTE AND CHRONIC AMBIENT AIR CONCENTRATIONS

Chemical	Acute AAC (mg/m3)	Chronic AAC (mg/m3)
1,1,1-Trichloroethane (Methyl Chloroform)	2,075	2.30E+00
1,1,2,2-Tetrachloroethane	18	3.27E-05
1,3-Butadiene	7,514	6.32E-05
1,4-Dichlorobenzene	300	3.06E-04
2,2,4-Trimethylpentane	900	N/A
2,4-Dinitrotoluene	5.0	2.13E-05
2-Chloroacetophenone	N/A	3.13E-05
Acetaldehyde	306	8.62E-04
Acetophenone	25	3.65E-01
Acrolein	0.23	2.09E-05
Acrylonitrile	38	2.79E-05
Antimony Compounds (Selected compound: Antimony)	13	1.46E-03
Arsenic Compounds (Selected compound: Arsenic)	2.5	4.41E-07
Benzene	1,276	2.43E-04
Benzyl Chloride	26	3.96E-05
Beryllium Compounds (Selected compound: Beryllium)	0.013	7.90E-07
Biphenyl	38	1.83E-01
bis(2-Ethylhexyl) Phthalate	13	4.80E-04
Bromoform	7.5	1.72E-03
Cadmium Compounds (Selected compound: Cadmium)	0.25	1.05E-06
Carbon Disulfide	311	7.30E-01
Carbon Tetrachloride	201	1.26E-04
Carbonyl Sulfide	30	N/A
Chlorobenzene	1,000	1.04E+00
Chloroform	195	3.58E-04
Chromium Compounds (Selected compound: Hexavalent Chromium)	0.10	1.58E-07
Cobalt Compounds (Selected compound: Cobalt)	10	6.86E-07
Cumene	935	4.17E-01
Cyanide Compounds (Selected compound: Hydrogen Cyanide)	3.9	3.13E-03
Dibenzofurans	25	7.30E-03
Dichloromethane (Methylene Chloride)	347	4.03E-03
Dimethyl formamide	164	3.13E-02
Dimethyl Sulfate	0.31	N/A
Ethyl Benzene	250	1.04E+00
Ethyl Chloride (Chloroethane)	1,250	1.04E+01
Ethylene Dibromide (Dibromoethane)	100	3.16E-06
Ethylene Dichloride (1,2-Dichloroethane)	405	7.29E-05
Ethylene glycol	50	4.17E-01
Ethylidene Dichloride (1,1-Dichloroethane)	6,250	5.21E-01
Formaldehyde	17	1.46E-04
Glycol Ethers (Selected compound: Diethylene glycol, monoethyl ether)	250	3.14E-03
Hexachlorobenzene	0.50	4.12E-06
Hexane	11,649	2.21E+00
Hydrochloric Acid	16	2.09E-02
Hydrogen Fluoride (Hydrofluoric Acid)	9.8	1.46E-02

Isophorone	13	2.09E+00
Manganese Compounds (Selected compound: Manganese)	2.5	5.21E-05
Mercury Compounds (Selected compound: Elemental Mercury)	1.0	3.13E-04
Methanol	943	4.17E+00
Methyl Bromide	261	5.21E-03
Methyl Chloride	1,180	9.39E-02
Methyl Hydrazine	0.43	3.96E-07
Methyl Isobutyl Ketone (Hexone)	500	3.13E+00
Methyl Methacrylate	311	7.30E-01
Methyl Tert-Butyl Ether	1,444	7.40E-03
N, N-Dimethylaniline	25	7.30E-03
Naphthalene	75	5.58E-05
Nickel Compounds (Selected compound: Nickel Refinery Dust)	5.0	7.90E-06
Phenol	58	2.09E-01
Polychlorinated Biphenyls (Selected Compound: Aroclor 1254)	2.5	1.90E-05
Polycyclic Organic Matter (Selected compound: Benzo(a)pyrene)	5.0	2.02E-06
Propionaldehyde	403	8.62E-04
Propylene Dichloride	250	4.17E-03
Selenium Compounds (Selected compound: Selenium)	0.50	1.83E-02
Styrene	554	1.04E+00
Tetrachloroethylene (Perchlorethylene)	814	3.20E-04
Toluene	1,923	5.21E+00
Trichloroethylene	1,450	1.68E-05
Vinyl Acetate	387	2.09E-01
Vinyl Chloride	2,099	2.15E-04
Vinylidene Chloride (1,2-Dichloroethylene)	38	2.09E-01
Xylene (Mixed Isomers)	1,736	1.04E-01