United States
Environmental Protection
Agency New England

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FACT SHEET

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EPA Draft Permit

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I. Background

On May 31, 2006, Northeast Energy Associates, LP (NEA), submitted an initial application to EPA requesting a revision to its prevention of significant deterioration (PSD) permit issued to NEA's cogeneration facility on Depot Street in Bellingham, Massachusetts. This facility consists primarily of 2 gas turbines with heat recovery units capable of producing 304 megawatts of electricity.

The Massachusetts Department of Environmental Protection (DEP) originally issued the PSD permit on February 1, 1989. The permit included conditions that restricted the combustion of fuel oil to "periods of natural gas curtailment." The permit also limited the number of hours that NEA could combust fuel oil over any 12 month period. NEA's application asked EPA to revise permit condition 2 of the permit's Operating Conditions and Restriction section. Condition 2 restricts the number of hours that NEA may burn fuel oil. Since this restriction could also limit sulfur dioxide (SO2) and particulate emissions from the facility, it is also part of the original permit's Best Available Control Technology (BACT) determination for sulfur dioxide and particulate emissions.

This proposed change constitutes a change in the method of operation (change) under EPA's PSD program. Under the PSD program, NEA is required to obtain a new PSD permit prior to making the change if the change results in a net significant emission increase at the permitted facility. NEA is also required to apply for a revised PSD permit for any change that modifies an existing PSD permit term or condition.

Initially, NEA requested to increase the amount of fuel oil the facility may combust during any 12 month period and to remove the permit condition that allowed the use of fuel oil only during periods when natural gas was unavailable due to curtailment. The request also included the maximum number of hours that NEA would combust fuel oil during any 12 month period. In a letter dated March 19, 2007, NEA clarified that the maximum hours of operation was a projection of its future operations and not an enforceable operational restriction. NEA explained that it included the hours of operation to support its demonstration that the removal of the fuel oil restriction would not result in a significant emission increase.

The letter included NEA's emission calculations based on the federal PSD actual-to-projected actual emission test (see 40 CFR 52.21(a)(2)(iv)(c)). The calculations showed that the operational changes would not result in a net significant increase of any pollutant regulated under the PSD program. Since NEA's projected actual emissions are below the federal PSD major modification threshold levels, EPA is not proposing to establish new limits that address possible emission increases that may occur from this change. However, NEA will need to continue to demonstrate that there is no significant emission increase due to the change by keeping proper records for 10 years. See Appendix A for the applicable PSD regulations for this permit modification.

During a meeting between NEA and EPA on April 18, 2007, NEA decided to revise other existing PSD permit conditions to make them consistent with the DEP's current permits. These revisions include new NOx, CO, and VOC emission limits for startup and shutdown periods. NEA also requested that DEP and EPA both allow for a higher opacity limit during startup and shutdown operations when firing fuel oil and during fuel switching. In letters dated June 29, 2007, August 20, 2007, and October 4, 2007, NEA formally requested EPA to draft PSD revisions to include these changes. The letters also included information to support these permit revisions. In addition, NEA submitted further information on January 11, 2008 which resulted in further exchange of information as late as June 10, 2008. EPA determined that NEA's application for a permit modification was complete with the information contained in the e-mail on January 11, 2008.

EPA is proposing to approve NEA's applications and has drafted modifications to the existing PSD permit to reflect NEA's request. EPA's permit decisions are based on the information and analysis provided by the applicant and the Agency's own technical expertise. This fact sheet documents the information and analysis EPA used to support the PSD permit decisions. It includes a description of the proposed facility, the applicable requirements, and an analysis showing how the applicant complied with the requirements. EPA is authorized to revise the original PSD permit since Massachusetts returned the PSD program to EPA on March 3, 2003.

II. <u>Emission projection</u>

NEA's application included emission calculations showing that the various operational changes would not result in a significant net emission increase. NEA calculated that the difference between the projected-actual emissions (defined in 40 CFR 52.21(b)(41)) and the baseline actual emission (defined at 40 CFR 52.21(b)(48)) is not significant (defined at 40 CFR 52.21(b)(23)). For calculating its baseline emissions, NEA used its actual emissions that occurred during 2001-2002 period. This 24 consecutive month period is consistent with EPA's definition for calculating baseline emissions (See 40 CFR 52.21(b)(48)). NEA projected its future actual emissions based on its anticipated business activities that may result from the removal of oil-firing restrictions. NEA calculated that the difference between the projected actual emission and baseline actual emissions will be less than the federal significant levels. Table I contains the baseline emissions, projected actual emissions and significance levels used in NEA's demonstration for each pollutant.

Table I
Levels of Significant Net Emission Increase

Pollutant	Baseline Emission Rate	Projected Actual Emission Rate	Projected Increase	Significant Increase Threshold for this Pollutant
NOx	954	978	24	40
CO	216	315	99	100
SO2	7	46	39	40
VOC	22	46	24	40
PM-10	37	51	14	15

An analysis of particulate matter was not conducted since the test method (40 CFR Part 60, Appendix A, method 5) proposed in this permit and the test data used in the baseline emission calculation cannot distinguish between particulate matter of 10 microns or less in diameter (PM-10) and PM emissions. Therefore all PM emissions are assumed to be PM-10. Since the significance level for PM emissions is higher than PM-10 (25 tons versus 15 tons), and the PM-10 significance level was not exceeded, even using the highly conservative assumption that all PM emissions were PM-10, PM emissions were not analyzed.

The actual-to-projected-actual applicability test requires a source to project its actual emissions that may occur during the next ten years. Because NEA's projected increases are just below the significance levels for these pollutants, there is a reasonable chance that NEA's proposed changes may result in a significant emission increase. Therefore, EPA is proposing to include additional record keeping, reporting, and emission testing to the existing PSD permit. The additional compliance requirements will ensure that NEA properly documents that the change did not require a PSD permit as required by 40 CFR 52.21(b)(41).

To identify the records and emission testing that are necessary to insure actual emissions do not exceed significance levels, NEA determined which pollutant increase will first approach the significance level when combusting either oil or gas. In Table II, hours of operation were calculated for each pollutant using the combined maximum rated heat input for the two turbines and multiplying by the permitted emission rate. This results in the maximum number of hours the turbines can be used before the emission increase meets the significant threshold for the pollutant as contained in Table I. The lowest operating hours is then used to determine which pollutant should be monitored. As demonstrated in Table II, SO2 is the pollutant where the hours of operation are the lowest if NEA burned 0.2 percent by weight number 2 fuel oil. However, in its application, NEA proposes to use ultra low sulfur diesel (ULSD) for its oil consumption, which has a maximum sulfur content of 0.0015 percent by weight. When using ULSD, PM-10, measured as PM, becomes the first pollutant to exceed the significance levels if NEA increases oil combustion.

Historically, NEA has seldom used oil and therefore has very limited information regarding PM-10 emissions. Also, it is possible that ULSD will have lower PM-10 emissions than number 2 fuel oil. Because of the limited data and future uncertainties, EPA is requiring stack testing for PM-10 to ensure that variations in the PM-10 emission rate do not result in an exceedance of a significance level during any 12 month period. Therefore, to track future PM-10 emissions, EPA is proposing to periodically stack test for PM-10 emissions when firing oil, require the facility to record the amount of sulfur in oil, and keep records of the amount of fuel combusted.

In determining the frequency for stack testing PM-10 emissions, EPA took into account that fact that NEA's decision to use ULSD is a business decision that could result in long operating periods without using ULSD. Since ULSD results in more emissions than natural gas of all pollutants except for SO2, EPA does not want to force NEA to burn ULSD by requiring stack testing within a defined timeframe. Instead, EPA is deriving the test frequency using the hours of operation on ULSD from Table II. If NEA operated at maximum capacity on ULSD at the permitted levels for PM-10, a significant emission increase would occur after 625 hours of operation. Since EPA usually requires emission testing between 60 and 180 days of initial operations, EPA is proposing to require NEA to stack test for PM-10 emissions before it reaches 250 stack operating hours on ULSD or within 90 calendar days thereafter if additional time is needed to schedule the test. After the initial test, EPA is requiring NEA to test based on the operating hours (every 600 hours, approximately equivalent to one year of burning ULSD, for a period of five years following the effective date of the permit or after three separate stack tests, whichever comes last).

When combusting natural gas, the amount of gas that can be burned in a 12 month period is limited by carbon monoxide (CO) emissions. Since the facility has a continuous emission monitor for CO, the data from this monitor will be used to determine that the change does not significantly increase CO emissions.

Table II
Determination of the Most Restrictive Pollutant

Pollutant	Emission Cap	Emission Cap (lbs)	Emission Factor Oil (lbs/MMBtu)	Design heat input (MMBtu/hr)	Hours of Operation	Oil Usage (gal)
For Oil (ULSD)						
PM-10	50	100,000	0.0647	2,472	625	10,884,472
SO2	43	86,000	0.0016	2,472	8,760	152,556,759
VOC	44	88,000	0.0151	2,472	2,358	41,040,948
NOx	978	1,956,000	0.1497	2,472	5,286	92,015,016
CO	315	630,000	0.3277	2,472	778	13,538,663
SO2 higher sulfur oil	43	86,000	0.2136	2472	163	2,835,364
For Gas						
						MMBtu Total
PM-10	50	100,000	0.0047	2560	8,311	21,276,596
SO2	43	86,000	0.0016	2560	8,760	22,246,060
VOC	44	88,000	0.0043	2560	7,994	20,465,116
NOx	978	1,956,000	0.0859	2560	8,760	22,246,060
CO	315	630,000	0.0516	2560	4,769	12,209,302

Note 1: Some of the calculated hours of operation in Table II resulted in operating hours that exceeded the maximum hours in a year (8760). Therefore, the hours of operation for NOx and SO2 emissions when burning gas and SO2 emissions when burning ULSD in table II were limited to 8760 hours.

Note 2: "Hours of Operation" assumes that both turbines are operating at their design heat input. If only one turbine operates, the hours of operation would be doubled.

Note 3: Entry for emissions from higher sulfur oil is for comparison purposes only.

III. Emission projections and existing annual emission caps

Table V in Condition C.2 of the proposed permit contains annual mass emission limits that are the same as the original PSD permit. These emission limits are higher than the projected actual emissions contained in Table I of this document because of the differences in how both yearly emission rates were derived. For the original PSD permit, the yearly emission rate is based on 8760 hours of operation assuming the highest allowable emission rates (720 hours on oil and 8040 hours on natural gas). The annual projected actual emissions in Table I of this document and in the narrative section of the PSD permit, were derived differently using actual emissions averaged over two years (baseline) and estimating that future actual emissions will not exceed the baseline plus a significance amount that would require a new PSD permit instead of modifying the existing PSD permit. These significant amounts are defined in 40 CFR 52.21(b)(23)(i) and are listed earlier in Table I.

IV. BACT Analysis

As stated earlier, NEA's proposal to remove the restriction on the amount and timing of fuel oil combustion is a change to the original permit's BACT analysis. See "Control Technology Review" on page 7 of support document for the original PSD permit titled "Determination for PSD Permit Application #CR-88-PSD-c-001." Therefore, EPA must determine if the increase in fuel oil combustion would result in a BACT determination different from the original.

At the time of this permit amendment, NEA has approximately 73,000 gallons of number 2 fuel oil in its storage tanks. NEA will be allowed to burn this oil but will be prohibited from receiving any new shipments of number 2 fuel oil. In place of number 2 fuel oil, NEA is limited in Condition B.3.to using ultra low sulfur diesel (ULSD) by requiring any future fuel oil meet a sulfur-in-fuel limit of 15 ppm by weight.

Although PM-10 emissions from ULSD may be lower than PM-10 emissions from number 2 fuel oil, the emissions are still higher when compared to natural gas. However, NEA has projected future actual PM-10 emissions to be 51 tons per year which are still lower than projected emissions at the time of the original BACT analysis (105 tons). Accordingly, EPA concludes that the revisions do not affect the existing BACT findings or require additional BACT analysis beyond requiring ULSD as the fuel oil.

V. Modeling analysis

The PSD regulations require an ambient air quality impact analysis to determine the impacts of a proposed permit action on ambient air quality. For all regulated pollutants emitted in significant amounts, the analysis must consider whether the proposed project will cause or contribute to a violation of (1) the NAAQS and (2) the applicable PSD increments. 40 CFR 52.21(k), (m).

Since the proposed permit revisions do not alter any emission limitation that was used in original PSD permit's air quality modeling analysis, the prior analysis carried out for the permit remains applicable. Accordingly, EPA concludes that the remaining proposed permit revisions will not cause or contribute to a violation of a NAAQS or applicable

PSD increment.

VI. Endangered Species Act/ESA

Section 7 of the ESA requires that certain federal actions such as federal PSD permits address the protection of endangered species in accordance with the ESA. To comply with the ESA, Region 1 consulted with the United States Fish and Wildlife Department (FWS)-New England Field Office web site
http://www.fws.gov/northeast/newenglandfieldoffice/EndangeredSpec-Consultation_Project_Review.htm
to determine if the proposed revisions to EPA's Bellingham PSD permit posed any risk to endangered species in Norfolk County, Massachusetts. Our consultation is consistent with the direction EPA received from the FWS in an e-mail on another PSD permit EPA is drafting. See the file for an e-mail from Anthony Tur of FWS to Phyllis Nelson of EPA dated November 20, 2007.

The website instructs EPA to review a list of endangered species by county and determine if an endangered species is located in the county for the permitted facility. Bellingham is in Norfolk County. According to the table on the web site, there are no listed endangered species for Norfolk County. Therefore, it has been concluded that the proposed permit revisions do not pose a threat to any endangered or proposed endangered species or their habitat in the area subject to FWS jurisdiction, and that no further ESA impact analysis is required. The web site directed EPA to print a letter dated January 1, 2008 and signed by Anthony P. Tur, Endangered Species Specialist for FWS. The letter states that no further review is warranted. The file contains a copy of this letter.

VII. Increased emission limits during startup and shut down.

When the DEP issued the original NEA PSD permit in 1989, it only included one set of emission limits that applied to all operations including startup and shutdown operations. However, as with other combined cycle generating facilities, Massachusetts and EPA have found emissions during startup and shutdown to be higher than steady state operations. Permits issued today by Massachusetts and more recently by EPA for the Fore River facility, usually contain higher emissions for startup and shutdown operations to address the difficulty of limiting emissions during these periods and to more accurately reflect the reality of the facility's emissions. The proposed PSD permit now contains special conditions allowing NEA to have higher emissions during startup and shutdown.

In a letter dated June 29, 2007, NEA submitted emission data based on continuous emission monitors (CEMs) for NOx and CO emissions during startup and shutdown when firing natural gas. The data represents emissions from only one turbine. Historically, NEA has started operations by separately bringing each turbine on line. However, in the future, NEA may be required by its power contract to start the turbines simultaneously. The permit limit during startup and shutdown reflects the possibility that the stack emissions would double if both turbines are started simultaneously.

Since NEA has no data on oil firing during startup and shutdown, the emission data used to establish the permit emission limits during these types of operations is based only on natural gas firing. As evidenced by the existing permitted emission limits during steady state operations and EPA's experience with other dual fuel-fired combustion turbines, EPA believes emissions during oil firing would be higher when compared to gas firing. However, NEA is prepared, when firing oil, to comply with the same emission limits the draft permit establishes for startup and shutdown when firing gas. Therefore, basing the NOx emission rate for startup and shutdown on data only using gas firing represents BACT during startup and shutdown since NOx emissions will probably be higher when burning ultra low sulfur diesel. Based on the graphs depicting NOx emissions during startup and shutdown and allowing for a nominal compliance factor of roughly 20%, the emission data contained within the June 29, 2007 letter supports the NOx emission limits NEA is requesting for startup and shutdown. In the proposed permit, NOx emissions during each two hour period of startup and shutdown were increased from 740 pounds to 1730 pounds (865 lbs/hr) during startup and 740 pounds to 2160 pounds (1080 lbs/hr) during shutdown (when firing gas or oil). The timeframe for startup and shutdown is defined in the permit and cannot exceed 2 hours (i.e. measured as 120 minutes from light-off).

NEA also requested in the June 29, 2007 letter to increase the mass emission limit for VOCs and CO during startup and shutdown. Based on the emission data contained in the letter, the requested increase in the mass emission rate is not justified when burning natural gas. Mass CO emissions exceeded the original CO emission limit only on a few occasions. NEA has not submitted information to EPA that describes the facility's operations during these few occasions, which could have been caused by upset conditions. EPA does not base BACT determinations on upset conditions, therefore EPA is denying NEA's request to raise the mass CO emission rate when burning natural gas from 132 pounds per hour to 1000 pounds per hour. However, to address short term emission spikes, EPA is allowing mass CO emissions during startup and shutdown to be averaged over two hours.

Similarly, EPA is increasing the averaging time from one hour to two for the VOC emission limit for startup and shutdown since the requested VOC emission rate was derived from the CO emission rate. See November 21, 2007, Sean Gregory e-mail.

The proposed permit also contains higher concentration based emission rates for NOx, VOC, and CO emissions during startup and shutdown. These higher concentration rates were calculated based on 50% load at the allowable mass based emission limits.

VIII. Opacity

In a letter dated August 20, 2007, NEA expressed concerns that the current opacity limit of 10% may not be achievable during startup and shutdown when combusting oil. NEA only had data for one abbreviated startup on oil that indicated a 10% opacity limit may not be feasible. To address this issue, the proposed permit requires NEA to conduct testing during startup and shutdown when combusting oil. NEA will also conduct testing during fuel switching, which may also cause a short term spike in opacity. Within the test period, the opacity limit during these limited operations will be the same as the opacity limit contained in the Massachusetts State Implementation Plan Regulations (SIP). 310 CMR 7.06(1)(b) requires:

"Opacity. No person shall cause, suffer, allow or permit the operation of a facility so as to emit contaminant(s), exclusive of uncombined water or smoke subject to 310 CMR 7.06(1)(a) of such opacity which, in the opinion of the Department, could be reasonably controlled through the application of modern technology of control and a good Standard Operating Procedure, and in no case, shall exceed 20% opacity for a period or aggregate period of time in excess of two minutes during any one hour provided that, at no time during the said two minutes shall the opacity exceed 40%."

After the testing is completed NEA will share the data with EPA. After studying the data the permit will be revised to include a final opacity limit for startup, shutdown, and fuel switching when combusting oil, along with parameter(s) monitoring and operational ranges for said parameter(s). In no case shall the permitted opacity limit be higher than the SIP.

IX. Continuous Emission Monitoring

During discussions with NEA, the company raised an issue about the location and number of continuous emission monitors at the facility. The original PSD permit can be interpreted to require a separate monitor for each stack. However, the current CEM system at the facility is installed in the common stack and is not physically able to directly measure emissions from each emission unit separately when they are firing simultaneously. In Massachusetts' plan approval dated May 4, 1992, the Commonwealth approved the CEM plan submitted by the permittee on November 26, 1990. This CEM plan stated that a probe could not be located in each emission unit's ductwork due to cyclonic flow. Instead the plan approved by the Commonwealth required the CEM systems' probe to be located in the common stack. Based on the history of the installation of the CEM system, EPA proposes to revise the PSD permit language to reflect that the installation of one CEM system for both units is acceptable. See permit condition E.1.

The permit provides that CEM readings will be attributed to each turbine by using approved methods from EPA's Acid Rain Program for combined stack emissions. Forty CFR Part 75, Appendix F, Section 5.6.1 calculates heat input for each turbine based on electric generation. NEA currently uses the following equation for purposes of the Acid Rain and NOx Budget Programs to allocate common pipe heat input to each turbine.

Eq.1 $HU_1 = HU_{cs}(T_{cs}/T_1)(MW_1*T_1/(MW_1*T_1+MW_2*T_2))$

Where:
HU_1= Heat input rate for unit 1, MMBtu/hr.
HU_{cs}= Heat input rate at the common pipe, MMBtu/hr.
MW_1= Gross electrical output for unit 1, MWe.
MW_2= Gross electrical output for unit 2, MWe.
T_1 Unit operating time for turbine 1, in $1/60^{th}$ of an hour
T_2 Unit operating time for turbine 2, in $1/60^{th}$ of an hour
Tcs= Common stack or common pipe operating time, in $1/60^{th}$ of an hour.

For purposes of the PSD permit, the combined emissions determined in the common stack will also be allocated according to the electricity each turbine produces.

Eq. 2 $EU_1 = EU_{cs}(T_{cs}/T_1)(MW_1*PL_1*T_1/(MW_1*PL_1*T_1+MW_2*PL_2*T_2))$

EU_1= Emission rate for unit 1, lbs/hr.
EU_{cs}= Emission rate at the common stack, lbs/hr.
MW_1= Gross electrical output for unit 1, MWe.
MW_2= Gross electrical output for unit 2, MWe.
PL_1=Depending on firing oil or natural gas, the appropriate emission limit from Tables I or 2 in lbs/MMBtu for unit 1
PL_2=Depending on firing oil or natural gas, the appropriate emission limit from Tables I or 2 in lbs/MMBtu for unit 2
T_1 Unit operating time for turbine 1, in $1/60^{th}$ of an hour.
T_2 Unit operating time for turbine 2, in $1/60^{th}$ of an hour.
Tcs= Common stack or common pipe operating time, in $1/60^{th}$ of an hour.

In order for Equations 1 and 2 to be representative of actual emissions from each turbine, the PSD permit has been clarified in two ways. First, emission data from the common stack will no longer be adjusted for load and ambient temperature. By removing these correction factors, the reported emission data and PSD permitted emission limits will be more reflective of actual ambient impacts.

Changes in operations also affect the usefulness of the data from equations 1 and 2. When one unit is in startup or shutdown mode while the other unit is operating outside of startup and shutdown, using equations 1 and 2 to apportion the emissions will not work. Prorating will not be done when one combustion turbine is in either startup and/or shutdown mode and the other combustion turbine is operating at steady state. All stack emissions will be attributed to one combustion turbine if the other combustion turbine is completely shutdown.

X. Clarification of when steam is injected to control NOx emissions

The original PSD permit required the facility to inject steam within 120 minutes from startup but did not have a similar provision during shutdown operations. The permittee submitted the following information in an e-mail dated January 11, 2008:

> "As load decreases, the steam extraction pressure will no longer be sufficient to meet the NOx injection requirements (when extraction pressure drops less than 70 psi greater than combustor shell pressure). This will occur when the load on the down coming CT reaches ~70 MW. As shown in the attached trend (print screen from the plant's DCS), at 70 MW, the steam turbine extraction pressure begins to degrade fairly rapidly. During a shutdown, steam injection is normally removed in the 60 - 70 MW range."

In other words, during shutdown as well as startup, steam pressure at the plant is insufficient to allow for steam injection. Based on this information, EPA proposes to allow for the removal of steam injection during shutdowns. See permit condition B.1.

XI. Rate of heat input for the two turbines

During the development of this permit, NEA and EPA conducted several discussions regarding a limit for maximum heat input. Unlike steam boilers, the maximum fuel a gas turbine utilizes in a given hour varies with ambient atmospheric conditions and maintenance schedules. In addition, each turbine has unique performance curves that allow operators to burn different fuel amounts to produce a given quantity of electricity depending on several variables. Due to the complex nature of varying design heat inputs, the draft PSD permit would need to contain several complicated mathematical equations that would soon become unwieldy to implement. EPA has decided not to include heat input as condition in the draft PSD permit.

EPA did request that NEA submit a maximum heat input for the turbines for two seasons, summer and winter. These numbers can be used as a baseline in the future if a question of whether a physical change or change in the method of operation resulted in an increase in the fuel capacity of the turbines. In an e-mail to EPA dated June 10, 2008, NEA's consultant supplied the maximum hourly combined heat input for the two turbines as 2883.4 MMBtu/hr in the winter and 2799.9 MMBtu/hr in the summer. These numbers were derived from analyzing actual heat inputs at the facility from 1999-2008.

Appendix A
Relevant Citations from 40 CFR 52.21

(a)(iv)(c) Actual-to-projected-actual applicability test for projects that only involve existing emissions units.

A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions (as defined in paragraph (b)(41) of this section) and the baseline actual emissions (as defined in paragraphs (b)(48)(i) and (ii) of this section), for each existing emissions unit, equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

(b)(41)(i) "Projected actual emissions" means the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.

(ii) In determining the projected actual emissions under paragraph (b)(41)(i) of this section (before beginning actual construction), the owner or operator of the major stationary source:

(a) Shall consider all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved State Implementation Plan; and

(b) Shall include fugitive emissions to the extent quantifiable and emissions associated with startups, shutdowns, and malfunctions; and

(c) Shall exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (b)(48) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth; or

(d) In lieu of using the method set out in paragraphs (a)(41)(ii)(a) through (c) of this section, may elect to use the emissions unit's potential to emit, in tons per year, as defined under paragraph (b)(4) of this section.

(b)(48) "Baseline actual emissions" means the rate of emissions, in tons per year, of a regulated NSR pollutant, as determined in accordance with paragraphs (b)(48)(i) through (iv) of this section.

(i) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

(a) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

(b) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above any emission limitation that was legally enforceable during the consecutive 24- month period.

(c) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive 24-month period can be used for each regulated NSR pollutant.

(d) The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by paragraph (b)(48)(i)(b) of this section.

(ii) For an existing emissions unit (other than an electric utility steam generating unit), baseline actual emissions means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the Administrator for a permit required under this section or by the reviewing authority for a permit required by a plan, whichever is earlier, except that the 10-year period shall not include any period earlier than November 15, 1990.

(a) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

(b) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above an emission limitation that was legally enforceable during the consecutive 24-month period.

(c) The average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had such major stationary source been required to comply with such limitations during the consecutive 24-month period. However, if an emission limitation is part of a maximum achievable control technology standard that the Administrator proposed or promulgated under part 63 of this chapter, the baseline actual emissions need only be adjusted if the State has taken credit for such emissions reductions in an attainment demonstration or maintenance plan consistent with the requirements of §51.165(a)(3)(ii)(G) of this chapter.

(d) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for all the emissions units being changed. A different consecutive 24-month period can be used For each regulated NSR pollutant.

(e) The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by paragraphs (b)(48)(ii)(b) and (c) of this section.

(iii) For a new emissions unit, the baseline actual emissions for purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero; and thereafter, for all other purposes, shall equal the unit's potential to emit.

(iv) For a PAL for a stationary source, the baseline actual emissions shall be calculated for existing electric utility steam generating units in accordance with the procedures contained in paragraph (b)(48)(i) of this section, for other existing emissions units in accordance with the procedures contained in paragraph (b)(48)(ii) of this section, and for a new emissions unit in accordance with the procedures contained in paragraph (b)(48)(iii) of this section.