some circumstances, it may be acceptable to establish BACT limits that can be adjusted or optimized as the performance of a technology becomes clearer after a period of operation.[116]

The permitting authority is also responsible for defining the form of the BACT limits, and making them enforceable as a practical matter.[117] In determining the form of the limit, the permitting authority should consider issues such as averaging times and units of measurement. For example, a final permit may include a limit based on pounds of emissions on a 24-hour rolling average or a limit representing a percentage of pollutant per weight allowed in the fuel. When making sure the limit is practically enforceable, the permitting authority must include information regarding the methods that will be used for determining compliance with the limits (such as operational parameters, timing, testing methods, etc.) and ensure that there is no ambiguity in the permit terms themselves.[118]

Finally, the permitting authority bears the responsibility in Step 5 to fully justify the BACT decision in the permit record. Regardless of the control level proposed by the applicant as BACT, the ultimate determination of BACT is made by the permitting authority after public review is complete. 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 permitting authority to review the documentation and rationale presented in order to: (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 permitting authority does not accept the basis for the proposed elimination of a control option, the permitting authority 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 permitting authority's satisfaction an adequate demonstration for one or more control alternatives, the permitting authority 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.

GHG-Specific Considerations

We expect many permits issued after January 2, 2011, to initially place more of an emphasis on energy efficiency, given the role it plays in affecting emissions of GHGs. For energy producing sources, as noted above, one way to incorporate the energy efficiency of a process unit into the BACT analysis is to compare control effectiveness in BACT Step 3 based on output-based emissions of each of the control options. Even in cases where another metric is used in Step 3 to compare options, once an option is selected in Step 5, permitting authorities

[116] *In re AES Puerto Rico, L.P.*, 8 E.A.D. 324, 348-50 (EAB 1999), *In re Hadson Power 14-Buena Vista*, 4 E.A.D. 258, 291 (EAB 1992).
[117] *See generally* EPA Guidance on Limiting Potential to Emit (PTE) in New Source Permitting (June 13, 1989), *available at* http://www.epa.gov/reg3artd/permitting/t5_epa_guidance.htm.
[118] *In re Prairie State Generating Company*, 13 E.A.D. at 83, 120.

may consider converting the BACT emissions limit to a net output basis for the permitted emissions limit. EPA encourages permitting authorities to consider establishing an output-based BACT emissions limit, or a combination of output- and input-based limits, wherever feasible and appropriate to ensure that BACT is complied with at all levels of operation. Although developed as part of a voluntary program, EPA believes the draft handbook entitled *Output-Based Regulations: A Handbook for Air Regulators* (August 2004) may provide relevant information to assist permitting authorities in establishing limits based on output.[119] Furthermore, since the environmental concern with GHGs is with their cumulative impact in the environment, metrics should focus on longer-term averages (*e.g.,* 30- or 365-day rolling average) rather than short-term averages (*e.g.,* 3- or 24-hr rolling average).

In addition to a permit containing specific numerical emissions limits established in a BACT analysis, a permit can also include conditions requiring the use of a work practice such as an Environmental Management System (EMS) focused on energy efficiency as part of that BACT analysis. The ENERGY STAR program provides useful guidance on the elements of an energy management program. The inclusion of such a requirement would be appropriate where it is technically impractical to measure emissions and/or energy use from all of the equipment and processes of the plant and apply an output-based standard to each of them. For example, a candidate might be a factory with many different pieces of equipment and processes that use energy. In addition to a BACT emissions limit on the boiler providing energy, the permit could also lay out a requirement to implement an EMS along with a requirement that all suggested actions that result in net savings have to be implemented. Consequently, the plant will operate in the most efficient manner through gradual achievable improvements. However, design, equipment, or work practice standards may not be used in lieu of a numerical emissions limitation(s) unless there is a demonstration in the record that the criteria for applying such a standard are satisfied.

[119] *Output-Based Regulations: A Handbook for Air Regulators* (Draft Final Report) (August 2004), *available at* http://www.epa.gov/chp/documents/obr_final_9105.pdf.

IV. Other PSD Requirements

General Concepts

The PSD requirements include several provisions requiring new and modified major stationary sources to conduct air quality analyses that may involve air quality modeling and ambient monitoring. The applicant must demonstrate that the emissions of any regulated NSR pollutant do not cause or contribute to a violation of any NAAQS or PSD increments.[120] Several months of ambient air quality data must also be collected in some circumstances to support this analysis.[121] In addition, as part of the "additional impacts analysis," the applicant must provide an analysis of the air quality impact of the source or modification, including an analysis of the impairment to visibility, soils, and vegetation (but not vegetation with no significant commercial or recreational value) that would occur as a result of the source or modification and general commercial, residential, industrial, and other growth associated with the source or modification.[122] Under the federal PSD rules, this analysis may also include monitoring of visibility in any Federal Class I area near the source or modification "for such purposes and by such means as the Administrator deems necessary and appropriate."[123] A demonstration must be made that emissions will not cause or contribute to a violation of any Class I increment and will not have an adverse impact on any air quality related value (AQRV), as defined by the Federal Land Manager, in such area.[124] Under PSD, if a source's proposed project may impact a Class I area, the Federal Land Manager must be notified so this office may fulfill its responsibility for evaluating a source's projected impact on the AQRVs and recommending either approval or disapproval of the source's permit application based on anticipated impacts.

GHG-Specific Considerations

The Tailoring Rule includes the following statement with respect to these requirements:

> "There are currently no NAAQS or PSD increments established for GHGs, and therefore these PSD requirements would not apply for GHGs, even when PSD is triggered for GHGs. However, if PSD is triggered for a GHG emissions source, all regulated NSR pollutants which the new source emits in significant amounts would be subject to PSD requirements. Therefore, if a facility triggers review for regulated NSR pollutants that are non-GHG pollutants for which there are established NAAQS or increments, the air quality, additional impacts, and Class I requirements would apply to those pollutants."[125]

Since there are no NAAQS or PSD increments for GHGs,[126] the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause or

[120] 42 USC 7475(a)(3); 40 CFR 52.21(k); 40 CFR 51.166(k).
[121] 40 CFR 52.21(m); 40 CFR 51.166(m); 40 CFR 52.21(i)(5); 40 CFR 51.166(i)(5).
[122] 40 CFR 52.21(o); 40 CFR 51.166(o).
[123] 40 CFR 52.21(o)(3).
[124] 40 CFR 52.21(p); 40 CFR 51.166(p).
[125] 75 FR at 31520.
[126] In addition, GHGS have not been designated as a precursor for any criteria pollutant under section 302(g) of the Clean Air Act or in EPA's PSD rules.

contribute to a violation of the NAAQS is not applicable to GHGs. Thus, we do not recommend that PSD applicants be required to model or conduct ambient monitoring for CO_2 or GHGs.

Monitoring for GHGs is not required because EPA regulations provide an exemption in sections 52.21(i)(5)(iii) and 51.166(i)(5)(iii) for pollutants that are not listed in the appropriate section of the regulations, and GHGs are not currently included in that list. However, it should be noted that sections 52.21(m)(1)(ii) and 51.166(m)(1)(ii) of EPA's regulations apply to pollutants for which no NAAQS exists. These provisions call for collection of air quality monitoring data "as the Administrator determines is necessary to assess ambient air quality for that pollutant in any (or the) area that the emissions of that pollutant would affect." In the case of GHGs, the exemption in sections 52.21(i)(5)(iii) and 51.166(i)(5)(iii) is controlling since GHGs are not currently listed in the relevant paragraph. Nevertheless, EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs.

Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs.

Applicants and permitting authorities should note that, while we are not recommending these analyses for GHG emissions, the incorporation of GHGs into the PSD program does not change the need for sources and permitting authorities to address these requirements for other regulated NSR pollutants. Accordingly, if PSD is triggered for a GHG emissions source, all regulated NSR pollutants which the source emits in significant amounts would be subject to these other PSD requirements. Therefore, if a facility triggers review for regulated NSR pollutants that are non-GHG pollutants for which there are established NAAQS or increments, the air quality, additional impacts, and Class I requirements must be satisfied for those pollutants and the applicant and permitting authority are required to conduct the necessary analysis.

V. Title V Considerations

A. General Concepts and Title V Requirements

Under the CAA, major sources (and certain other sources) must apply for, and operate in accordance with, an operating permit that contains conditions necessary to assure compliance with all CAA requirements applicable to the source.[127] The operating permit requirements under title V are intended to improve sources' compliance with other CAA requirements. Title V generally does not add new pollution control requirements, but it does require that each permit contain all air quality control requirements or "applicable requirements" required under the CAA (*e.g.,* NSPS and SIP requirements, including PSD), and it requires that certain procedural requirements be followed, especially with respect to compliance with these requirements. "Applicable requirements" for title V purposes include stationary source requirements, but do not include mobile source requirements. Procedural requirements include providing review of permits by EPA, states, and the public, requiring permit holders to track, report, and annually certify their compliance status with respect to their permit requirements, and otherwise ensuring that permits contain conditions to assure compliance with applicable requirements.

This section discusses title V requirements as they pertain to GHGs. These include the applicability requirement for title V permitting due to GHG emissions (*e.g.*, when a source will become subject to title V for the first time due to its GHG emissions), and requirements for permit applications and permit content. Under Step 1 of the Tailoring Rule, no sources become major sources requiring a title V permit solely as a result of GHG emissions. Sources must address GHGs in a title V permit only if they must address GHGs in their PSD permit (thus, they are a PSD "anyway source" or undergo an "anyway modification"). Beginning in Step 2 of the Tailoring Rule, a stationary source may be a major source subject to title V permitting requirements solely on the basis of its GHG emissions, provided the source exceeds the thresholds established in the Tailoring Rule (discussed below).

Under both Step 1 and Step 2 of the Tailoring Rule, when a source is required to address GHGs in their title V permit, the permit needs to meet the generally applicable title V application and permitting requirements for GHGs, such as describing emissions of GHGs and including in the permit any applicable requirements for GHGs established under other CAA programs (*e.g.*, the PSD program). The source's operating permit application generally must contain emissions-related information for: (1) all pollutants for which the source is major (see the definition of "major stationary source" in 40 CFR 70.2, which incorporates the requirements that a pollutant be subject to regulation, and an emissions threshold for GHG); and (2) all emissions of "regulated air pollutants" (which, under 40 CFR 70.2, includes criteria pollutants, VOCs, and pollutants regulated under CAA Section 111 or 112 standards, but does not currently include GHGs). In addition, the permitting authority shall require sources to provide additional emissions information sufficient to verify which requirements are applicable to the source and

[127] Details of the title V program are addressed in rules promulgated by EPA – 40 CFR 70 addresses programs implemented by state and local agencies and tribes, and 40 CFR 71 addresses programs generally implemented by EPA.

other specific information that may be necessary to implement and enforce other applicable requirements of the CAA or to determine the applicability of such requirements.[128]

Since the Tailoring Rule establishes a phased applicability approach under title V, the pertinent requirements vary somewhat between the first two steps of the Tailoring Rule. The following is a summary of the key requirements and some general examples with respect to title V applicability and title V permitting requirements (including permit application and permit content) with respect to GHGs under Steps 1 and 2 of the Tailoring Rule.

B. Title V Applicability Requirements and GHGs

Applicability requirements for title V permitting as they apply to GHG emissions are summarized in the following table and explained in more detail in subsections V.B.1 and V.B.2 following the table:

Table V-A. Summary of Title V Applicability Criteria for Sources of GHGs

January 2, 2011, to June 30, 2011 **(Step 1 of the Tailoring Rule)**	**On or after July 1, 2011** **(Step 2 of the Tailoring Rule)**
No sources are subject to title V permitting solely as a result of their emissions of GHGs. (Thus, no new title V sources come into the title V program as a result of GHG emissions.) [However, for sources subject to, or that become newly subject to, title V for non-GHG pollutants (*i.e.*, PSD "anyway sources"), sources and permitting authorities need to meet the generally applicable title V application and permitting requirements as necessary to address GHGs, such as including in the permit any applicable requirements for GHGs established under other CAA programs.]*	The following sources are subject to title V permitting requirements as a result of their GHG emissions: • Existing or newly constructed GHG emission sources (not already subject to title V) that emit or have a PTE equal to or greater than: o 100,000 TPY CO_2e, **and** o 100 TPY GHGs mass basis [As with Step 1, for all PSD "anyway sources" subject to title V in Step 2, sources and permitting authorities need to meet the generally applicable title V application and permitting requirements as necessary to address GHGs, such as including in the permit any applicable requirements for GHGs established under other CAA programs]*

* It is expected, at least at the outset, that this will consist primarily of meeting application and permitting requirements necessary to assure compliance with PSD permitting requirements for GHGs. See accompanying text in Section V.C of this guidance for further discussion and examples.

1. *Applicability under Tailoring Rule Step* 1

Under Step 1, no sources are subject to title V permitting solely as a result of their emissions of GHGs. Thus no new title V sources come into the title V program solely as a result of GHG emissions. However, sources required to have title V permits because they are PSD "anyway sources" or undergo PSD "anyway modifications" will be required to address GHGs as

[128] 40 CFR 70.5.

part of their title V permitting to the extent necessary to assure compliance with GHG applicable requirements established under other CAA programs. Section C below describes how sources and permitting authorities should consider addressing GHG requirements in permitting actions.

2. *Applicability under Tailoring Rule Step 2*

Beginning in Step 2 of the Tailoring Rule, a stationary source may be a major source subject to title V permitting requirements solely on the basis of its GHG emissions, provided the source exceeds the thresholds established in the Tailoring Rule. GHG emission sources that emit or have the PTE at least 100,000 TPY CO_2e, and also emit or have the PTE 100 TPY of GHGs on a mass basis will be required to obtain a title V permit if they do not already have one. It is important to note that the requirement to obtain a title V permit will not, by itself, result in the triggering of additional substantive requirements for control of GHG. Rather, these new title V permits will simply incorporate whatever applicable CAA requirements, if any, apply to the source being permitted.

Both of the following conditions need to be met in order for title V to apply under Step 2 of the Tailoring Rule to a GHG emission source:

(1) An existing or newly constructed source emits or has the PTE GHGs in amounts that equal or exceed 100 TPY calculated as the sum of the six well-mixed GHGs on a mass basis (no GWPs applied).

(2) An existing or newly constructed source emits or has the PTE GHGs in amounts that equal or exceed 100,000 TPY calculated as the sum of the six well-mixed GHGs on a CO_2e basis (GWPs applied).

In Step 2, as under Step 1, for all sources otherwise subject to title V for non-GHG pollutants (*i.e.,* anyway sources), sources and permitting authorities will need to meet the generally applicable title V application and permitting requirements as they pertain to GHG applicable requirements established under other CAA programs (*e.g.,* the PSD program). See Section C below for further discussion of permitting requirements.

C. Permitting Requirements

Under both Steps 1 and 2 of the Tailoring Rule, as with other applicable requirements related to non-GHG pollutants, any applicable requirement for GHGs must be addressed in the title V permit (*i.e.,* the permit must contain conditions necessary to assure compliance with applicable requirements for GHGs). EPA anticipates that the initial applicable requirements for GHGs will be in the form of GHG control requirements resulting from PSD permitting actions. It is important to note that GHG reporting requirements for sources established under EPA's final rule for the mandatory reporting of GHGs (40 CFR Part 98: Mandatory Greenhouse Gas Reporting, hereafter referred to as the "GHG reporting rule") are currently not included in the definition of applicable requirement in 40 CFR 70.2 and 71.2. Although the requirements contained in the GHG reporting rule currently are not considered applicable requirements under the title V regulations, the source is not relieved from the requirement to comply with the GHG reporting rule separately from compliance with their title V operating permit. It is the responsibility of each source to determine the applicability of the GHG reporting rule and to comply with it, as necessary. However, since the requirements of the GHG reporting rule are not considered applicable requirements under title V, they do not need to be included in the title V permit.

Under both Steps 1 and 2 of the Tailoring Rule, sources will need to include in their title V permit applications, among other things: citation and descriptions of any applicable requirements for GHGs (*e.g.,* GHG BACT requirements resulting from a PSD review process), information pertaining to any associated monitoring and other compliance activities, and any other information considered necessary to determine the applicability of, and impose, any applicable requirements for GHGs. This is the same application information required under title V for applicable requirements pertaining to conventional pollutants.

As a general matter, all title V permits issued by permitting authorities must contain, among other things, emissions limitations and standards necessary to assure compliance with all applicable requirements for GHGs, all monitoring and testing required by applicable requirements for GHGs, and additional compliance certification, testing, monitoring, reporting, and recordkeeping requirements sufficient to assure compliance with GHG-related terms and conditions of the permit. Permitting authorities will also need to request from sources any information deemed necessary to determine or impose GHG applicable requirements.

It is possible that some sources will need to address GHG-related information in their applications even if they will ultimately not have any GHG-specific applicable requirements (such as a PSD-related BACT requirement for GHGs) included in their permit. This is because, as noted above, permitting authorities would need to request information related to identifying GHG emission sources and other information if they determine such information is necessary to determine applicable requirements. Following is an explanation of the basis for requesting this information and some examples of these types of scenarios under Steps 1 and 2 of the Tailoring Rule.

Under Step 1 of the Tailoring Rule, no source can be major for purposes of title V solely on the basis of its GHG emissions, so the requirement set forth in 40 CFR 70.5 for the source to provide emissions-related information for pollutants for which the source is major does not apply. In addition, as GHGs are not currently considered regulated air pollutants under the title V regulations, the requirement to provide emissions-related information for regulated air pollutants does not apply. However, consistent with the requirements set forth in 40 CFR 70.5, permitting authorities will need to ask for any emissions or other information they deem necessary to determine applicability of, or impose, a CAA requirement.[129] Therefore, during Step 1 of the Tailoring Rule, any source going through a title V permitting action (*i.e.,* applying for a title V operating permit or undergoing a permit revision, reopening or renewal) would need

[129] Note that the phrase "subject to regulation" in the definition of major source in the title V regulations affects when a source may be a major source subject to title V as a result of emissions of a pollutant. If a source is already subject to title V, its application must include any information considered necessary to determine or impose a GHG applicable requirement – this is true even before GHGs become "subject to regulation" for major sources purposes.

to provide GHG emissions or other information if a permitting authority needs the information to determine applicability of a CAA requirement (*e.g.,* PSD).[130] The following is an example of where this request for information might occur:

> *An existing title V source is making a physical change that triggers PSD for NO_X. This change will result in additional applicable requirements for NO_X emissions controls but, according to the applicant, does not trigger BACT review for GHGs. In this case, as part of its analysis of the application for permit revision under its title V program, the permitting authority may determine it necessary to verify that the project did not trigger BACT requirements for GHG emissions, and therefore may need to request the applicant to submit GHG emissions information related to the project sufficient for the permitting authority to determine that PSD did not apply for GHG emissions from the project. This information could include such items as identification and descriptions of any GHG emission units and estimates of GHG emissions associated with the modification project.*

Under Step 2 of the Tailoring Rule, beginning July 1, 2011, a stationary source may be subject to title V permitting requirements solely on the basis of its GHG emissions, provided the source is equal to or greater than the 100,000 TPY CO_2e subject to regulation threshold (as well as the 100 TPY major source mass-based threshold) on a PTE basis. As noted above, sources generally must provide information regarding all emissions of pollutants for which they are major. In many cases, particularly where the source has no applicable requirements for GHGs, emissions descriptions (instead of estimates) may be sufficient. For sources subject to the GHG reporting rule, the emissions description requirements in the title V rules will generally be satisfied by information provided under the reporting rule. Further elaboration on the requirement for emissions data is provided in the White Paper 1 guidance on title V.[131] The following is an example of a permitting scenario under title V during Step 2 of the Tailoring Rule:

> *As of July 1, 2011, an existing facility not previously subject to title V has a GHG PTE over 100,000 TPY CO_2e and over 100 TPY on a mass basis. Therefore, according to the Tailoring Rule applicability criteria for GHG sources, this source becomes subject to title V solely based on its GHG emissions as of July 1, 2011. First, it will need to apply for a title V permit within 12 months of July 1, 2011 (unless an earlier date has been established by the permitting authority). Second, assuming that the facility does not have any applicable requirements for GHG emissions (such as a GHG BACT requirement resulting from a PSD review), the permitting authority may deem it sufficient that the facility simply provide a description of the GHG emission sources at the facility that cause the facility to exceed the applicability criteria threshold for GHGs under title V, rather than a detailed quantification of its GHG emission sources. Lastly, the source would also need to provide other emissions information as necessary for non-GHG emission sources (e.g., information on emissions of regulated air pollutants, information for fee calculation, etc.)*

[130] 40 CFR 70.5(c)(5).
[131] Office of Air Quality Planning and Standards, *White Paper for Streamlined Development of Part 70 Permit Applications* (July 10, 1995).

It is also important to note that sources that are newly subject to title V solely as a result of their GHG emissions will also need to provide in their title V permit applications required information regarding all other applicable requirements that apply to it under the Act (*e.g.,* SIP regulations). The following is an example of this permitting scenario under Step 2 of the Tailoring Rule:

> *A facility becomes subject to title V permitting requirements solely on the basis of its GHG emissions on July 2, 2011, and, therefore, must apply for a title V permit. The facility has an applicable requirement, such as a SIP requirement imposing an opacity limit on fuel-burning equipment that lacks periodic monitoring and monitoring sufficient to assure compliance. Even if the newly subject title V source did not have any specific GHG-related requirements to include in the title V permit, under this scenario, the facility must propose appropriate monitoring, recordkeeping and reporting (MRR) to assure compliance with the opacity standard in its permit application and the permitting authority must add appropriate MRR to the operating permit for that opacity standard (which may be the MRR proposed by the facility or other requirements) under the authority of the Act.*

D. Title V Fees

EPA rules currently do not require sources to pay any title V fees based on GHG emissions or to otherwise quantify GHG emissions strictly for title V fee purposes. However, throughout Steps 1 and 2 of the Tailoring Rule, the statutory and regulatory requirement to collect fees sufficient to cover all reasonable (direct and indirect) costs required to develop and administer title V programs still applies.[132] Permitting authorities need to review resource needs for GHG-emitting sources and determine if their existing fee structure is adequate. If not, permitting authorities would need to raise fees to cover the direct and indirect costs of the program or develop alternative approaches. EPA will work with permitting authorities that request assistance concerning establishing title V fees related to GHG emissions.

E. Flexible Permits

The final Flexible Air Permitting Rule (74 FR 51418), promulgated on October 6, 2009, reflects EPA's policy and rules governing the use of flexible air permits. A flexible air permit (FAP) is a title V operating permit that by its design authorizes the source owner to make certain types or categories of physical and/or operational changes without further review or approval of the individual changes by the permitting authority. Flexible air permits cannot circumvent, modify, or contravene any applicable requirement and, instead, by their design must assure compliance with each one. Based on our evaluation of State FAP pilots in addition to providing greater operational flexibility, FAPs can result in greater environmental protection, lower administrative costs, pollution prevention and increased energy efficiency.

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[132] 42 USC 7661a(b)(3)(B); 40 CFR 70.9.

FAP approaches can significantly reduce the administrative resources associated with CAA permitting requirements and provide a streamlined path for installing new energy-efficient equipment at industrial facilities. While many energy-efficient equipment upgrades may not trigger air permitting requirements, some changes have the potential to trigger permitting actions or applicability determination activities. The combination of plantwide emissions limits, alternative operating scenarios, and/or advance approvals of categories of operational changes can eliminate the need for case-by-case evaluation (under title V and PSD/NSR) for future energy-efficient equipment upgrades, thereby reducing time delays, uncertainty, and transaction costs in making these changes. In the absence of FAP approaches, air permitting considerations may cause a facility to forego or delay energy-efficient equipment upgrades that have potential to trigger air permitting requirements. FAP approaches can be used to accommodate these types of changes in a streamlined manner that addresses all applicable regulatory requirements up-front.

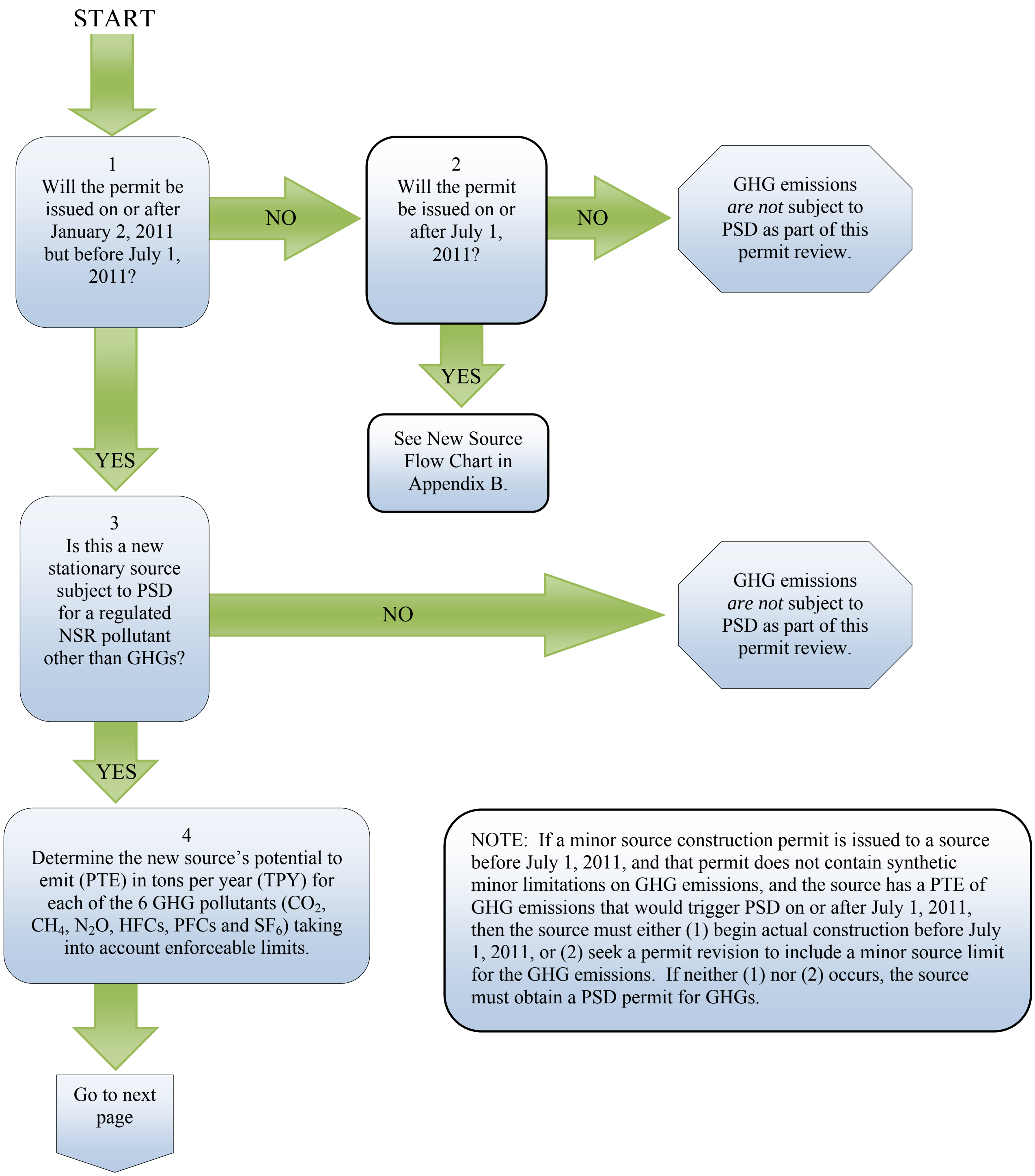
EPA encourages permitting authorities and sources to consider FAPs, particularly in situations where a source is planning to implement an ongoing program designed to improve energy efficiency and reduce GHG over time.

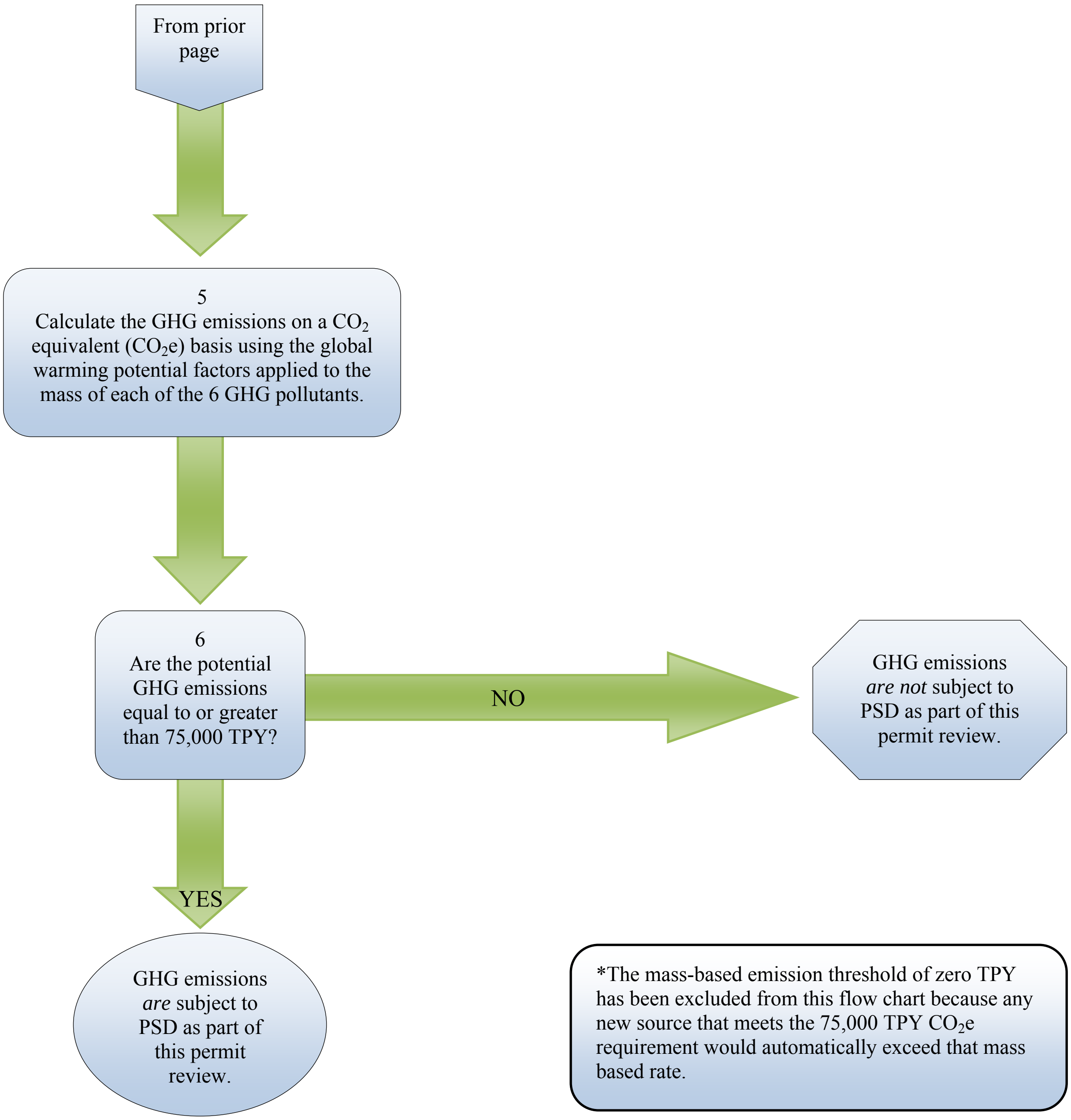
VI. Appendices

Note: The regulatory changes implemented in the Tailoring Rule set forth a two-part applicability process determining the applicability of PSD to GHGs, which first evaluates the sum of the GHG emissions on a CO_2e basis in order to determine whether the source's emissions are a regulated NSR pollutant, and, if so, then evaluates the sum of the GHG emissions on a mass basis in order to determine if there is a major source or major modification of such emissions. However, we noted in the Tailoring Rule preamble that most sources are likely to treat the mass-based analysis as an initial screen from a practical standpoint, since they would not proceed to calculate emissions on a CO_2e basis if they would not trigger PSD or title V on a mass basis.[133] Accordingly, the examples provided in the attached appendices take a variety of approaches for undertaking the required CO_2e and mass-based calculations, and permit applicants and permitting authorities may use the processes identified in this guidance or another process for determining applicability of PSD to GHGs in permits they issue, so long as their process complies with the relevant statutory and regulatory requirements.

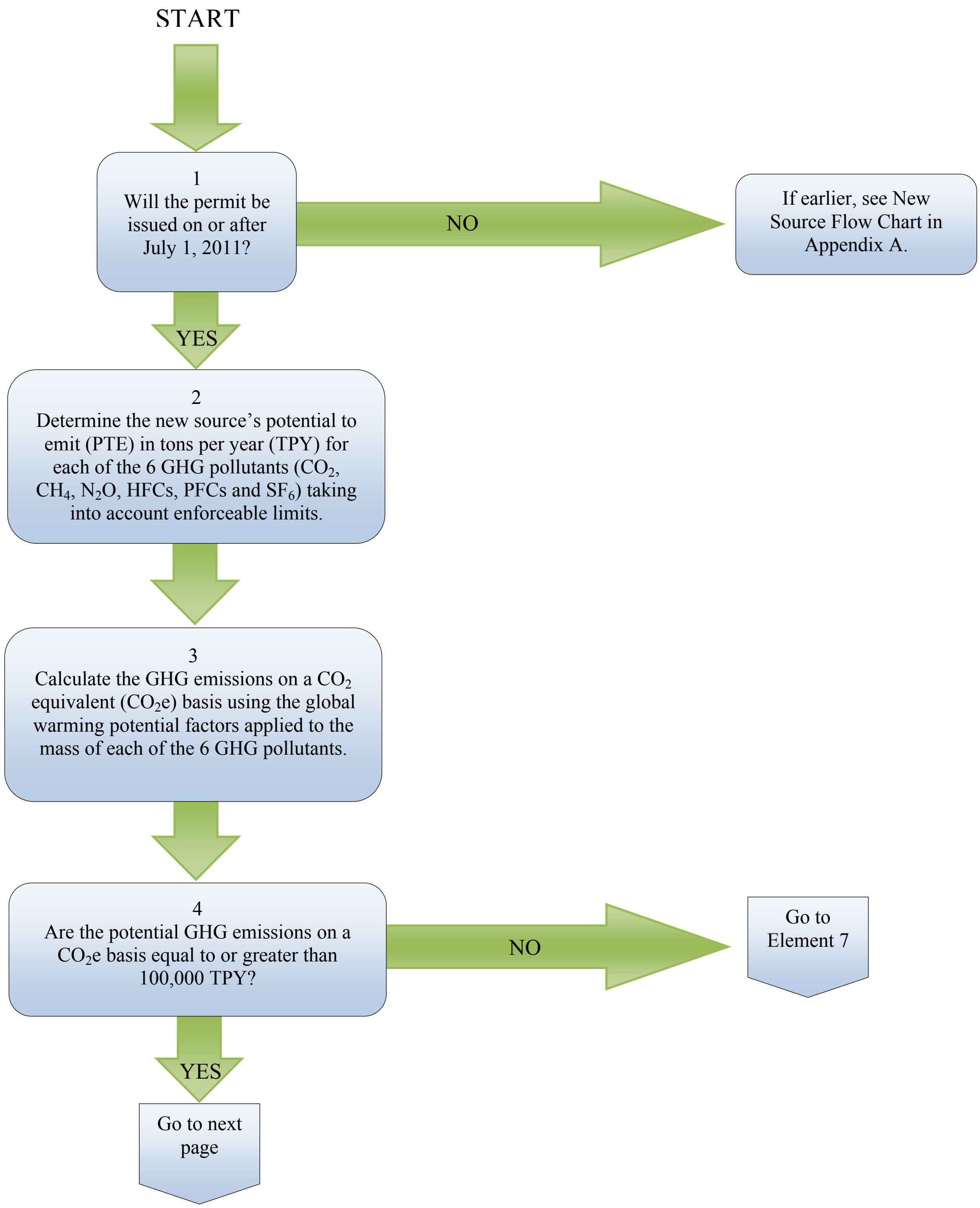
[133] 75 FR 31514, 31522 (June 3, 2010).

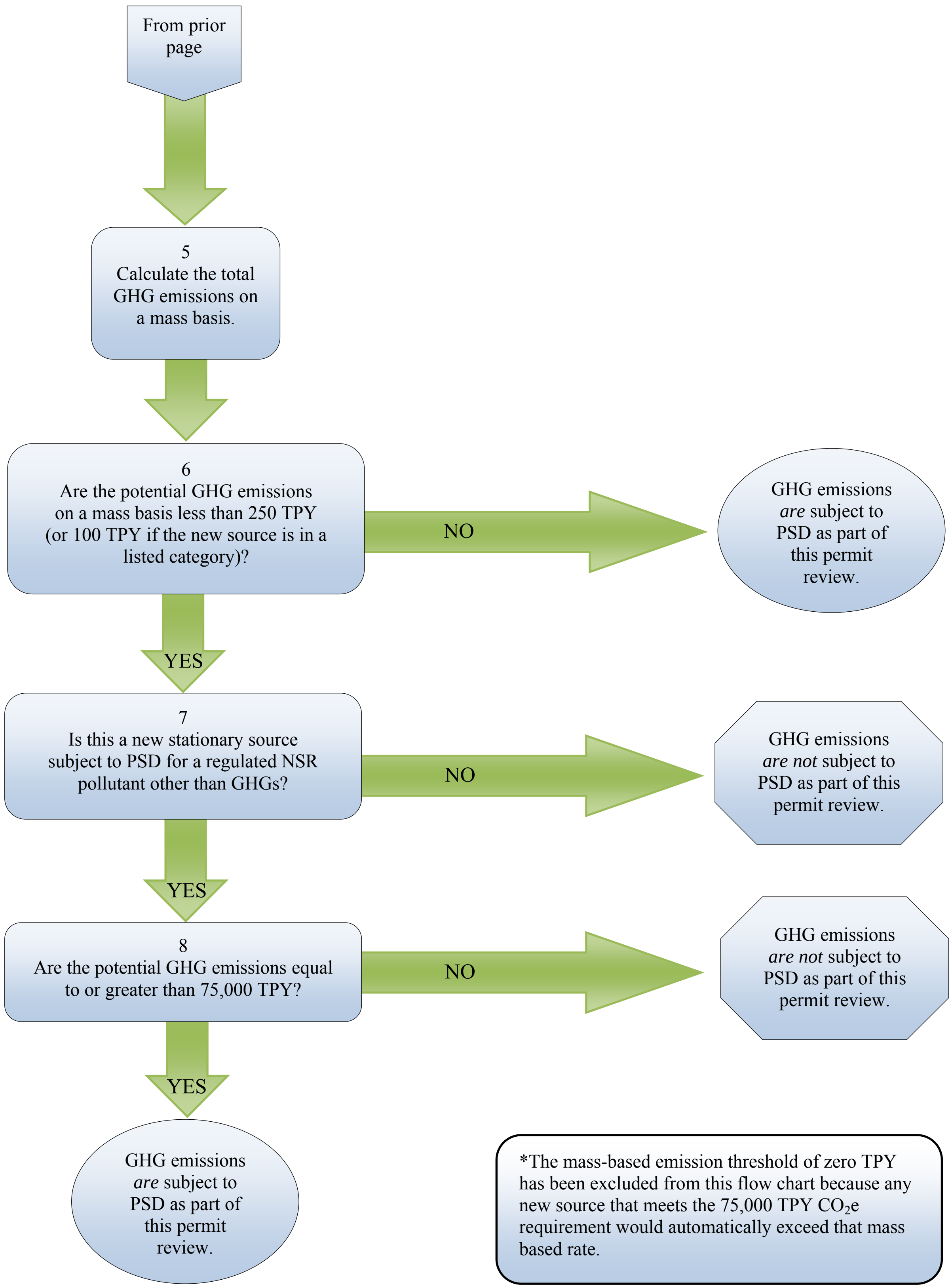
Appendix A. GHG Applicability Flow Chart – New Sources (January 2, 2011, through June 30, 2011)




From prior page
5
Calculate the GHG emissions on a CO_2 equivalent (CO_2e) basis using the global warming potential factors applied to the mass of each of the 6 GHG pollutants.
6
Are the potential GHG emissions equal to or greater than 75,000 TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
GHG emissions *are* subject to PSD as part of this permit review.
*The mass-based emission threshold of zero TPY has been excluded from this flow chart because any new source that meets the 75,000 TPY CO_2e requirement would automatically exceed that mass based rate.

Appendix B. GHG Applicability Flow Chart – New Sources (On or after July 1, 2011)




From prior page
5
Calculate the total GHG emissions on a mass basis.
6
Are the potential GHG emissions on a mass basis less than 250 TPY (or 100 TPY if the new source is in a listed category)?
NO
GHG emissions *are* subject to PSD as part of this permit review.
YES
7
Is this a new stationary source subject to PSD for a regulated NSR pollutant other than GHGs?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
8
Are the potential GHG emissions equal to or greater than 75,000 TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
GHG emissions *are* subject to PSD as part of this permit review.
*The mass-based emission threshold of zero TPY has been excluded from this flow chart because any new source that meets the 75,000 TPY CO_2e requirement would automatically exceed that mass based rate.

Appendix C. GHG Applicability Flow Chart – Modified Sources (January 2, 2011, through June 30, 2011)

START

1
Will the permit be issued on or after January 2, 2011 but before July 1, 2011?

NO → 2
YES → 3

2
Will the permit be issued on or after July 1, 2011?

NO → GHG emissions *are not* subject to PSD as part of this permit review.
YES → See Existing Source Flow Chart in Appendix D.

3
Is this modification subject to PSD permitting for a regulated NSR pollutant other than GHGs?

NO → GHG emissions *are not* subject to PSD as part of this permit review.
YES → 4

4
Determine the past actual (baseline) emissions in tons per year (TPY) for units that are part of the modification for each of the 6 GHG pollutants (CO_2, CH_4, N_2O, HFCs, PFCs and SF_6).
(For new units, the past actual emissions are zero.)

5
Determine the future projected actual emissions (or PTE) in TPY for units that are part of the modification for each of the 6 GHG pollutants.
(For new units that are not "replacement units," future actual emissions are equal to the PTE.)

Go to next page

NOTE: If a minor source construction permit is issued to a source before July 1, 2011, and that permit does not contain synthetic minor limitations on GHG emissions, and the source has a PTE of GHG emissions that would trigger PSD on or after July 1, 2011, then the source must either (1) begin actual construction before July 1, 2011, or (2) seek a permit revision to include a minor source limit for the GHG emissions. If neither (1) nor (2) occurs, the source must obtain a PSD permit for GHGs.

From prior page

6
For each unit, determine the increase or decrease in emissions of each of the 6 GHG pollutants by subtracting past actual emissions from future actual emissions.

7
For each unit, sum any increase or decrease in GHG emissions on a mass basis.

8
For all units that have an emissions increase, sum the GHG emissions on a mass basis.

9
Is the sum of GHG emissions increase greater than zero TPY?

NO

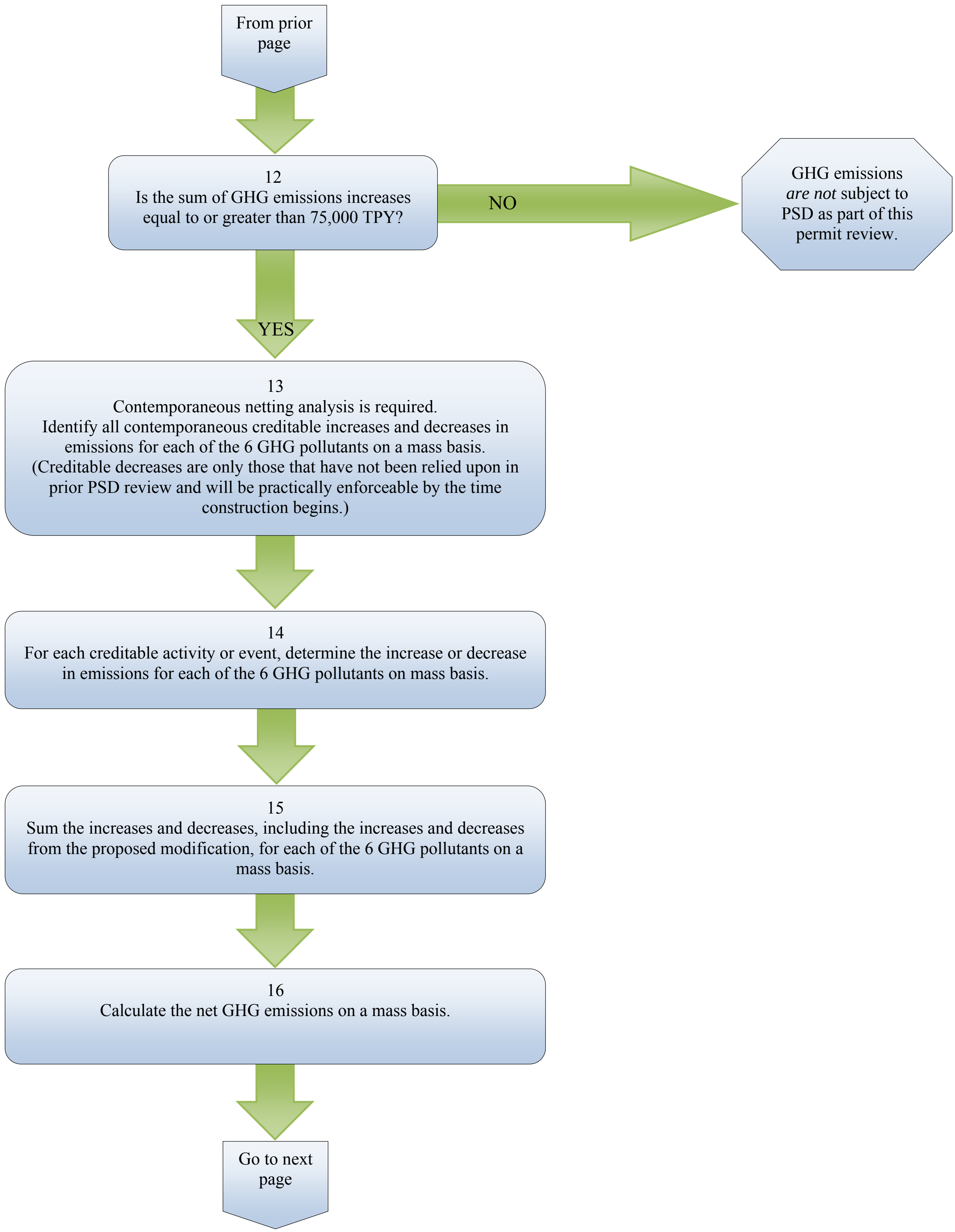
GHG emissions *are not* subject to PSD as part of this permit review.

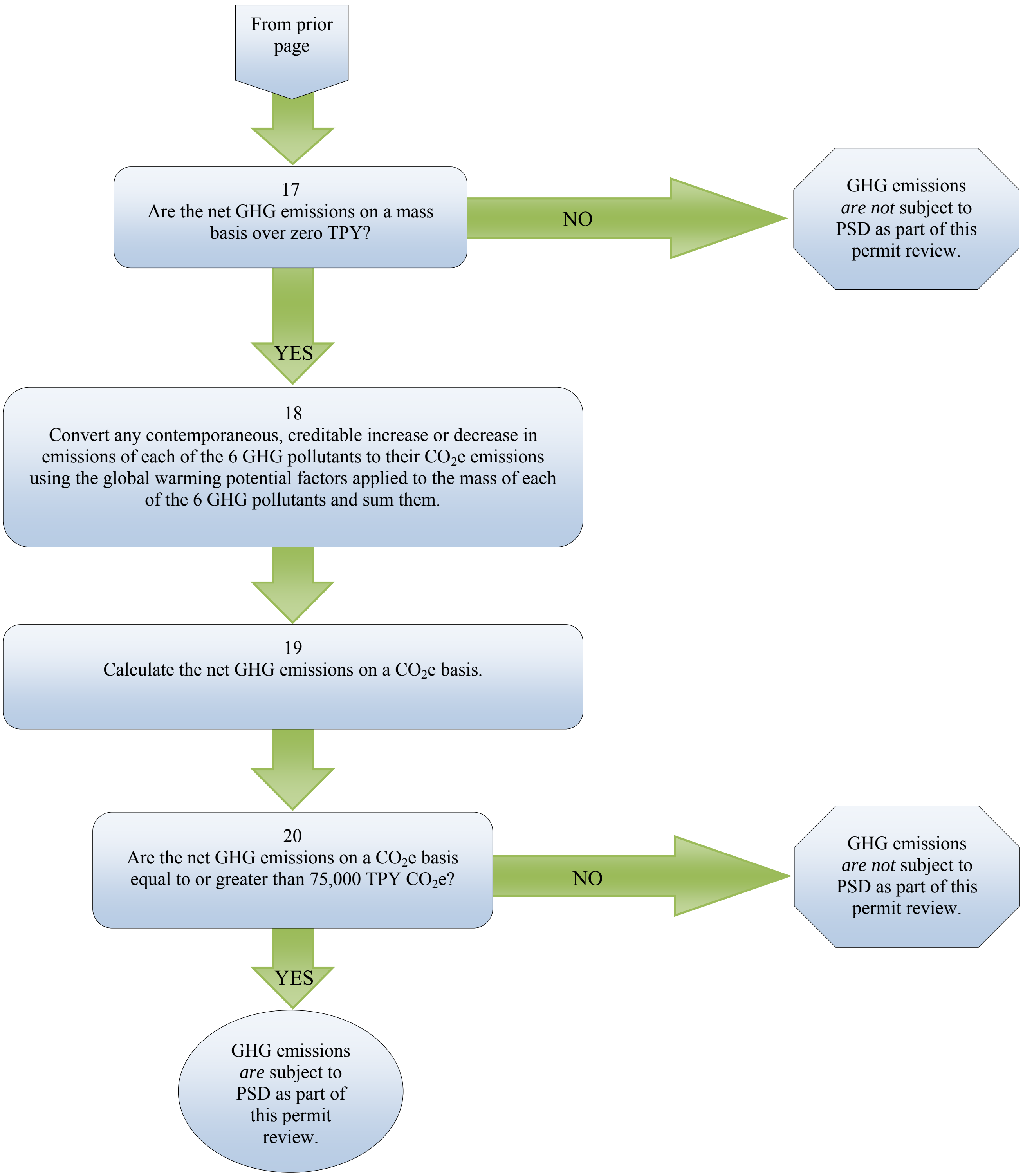
YES

10
For each unit, convert any increase or decrease in emissions of each of the 6 GHG pollutants to their CO_2 equivalent (CO_2e) emissions using the global warming potential factors applied to the mass of each of the 6 GHG pollutants and sum them for each unit to arrive at one GHG CO_2e number for each unit.

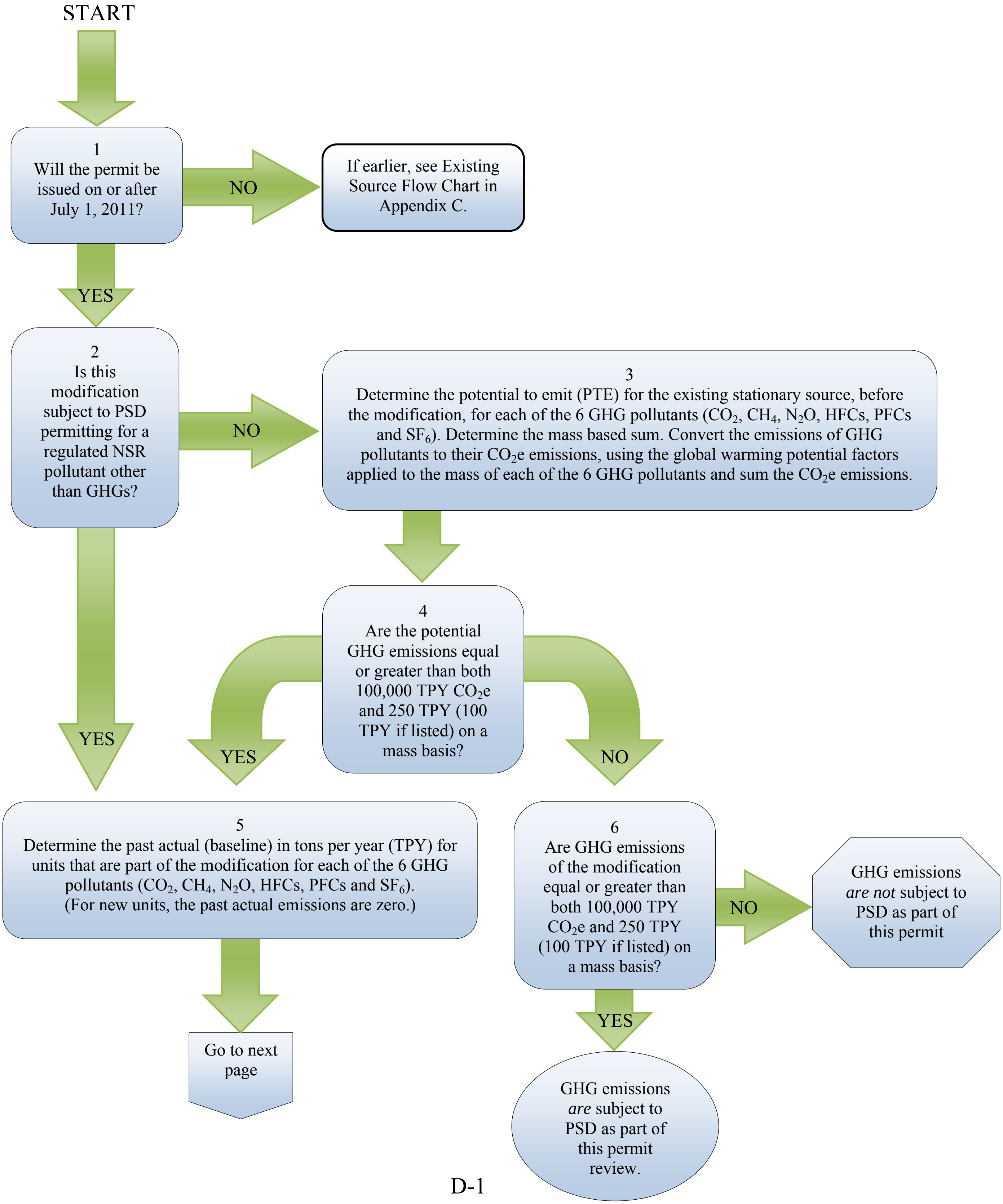
11
For all units that have an emissions increase, sum the GHG emissions on a CO_2e basis. (Emission decreases are not considered at this step.)

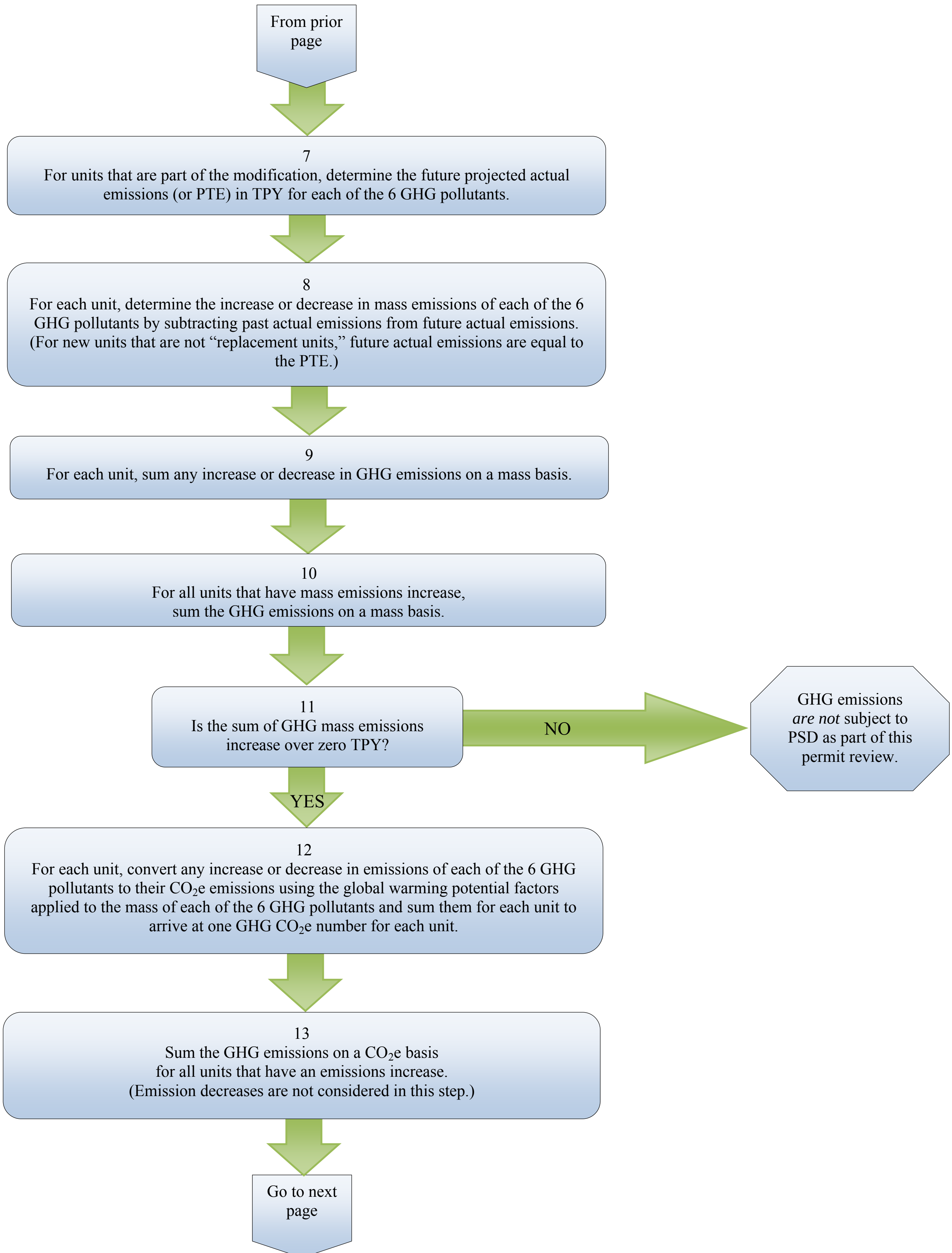
Go to next page

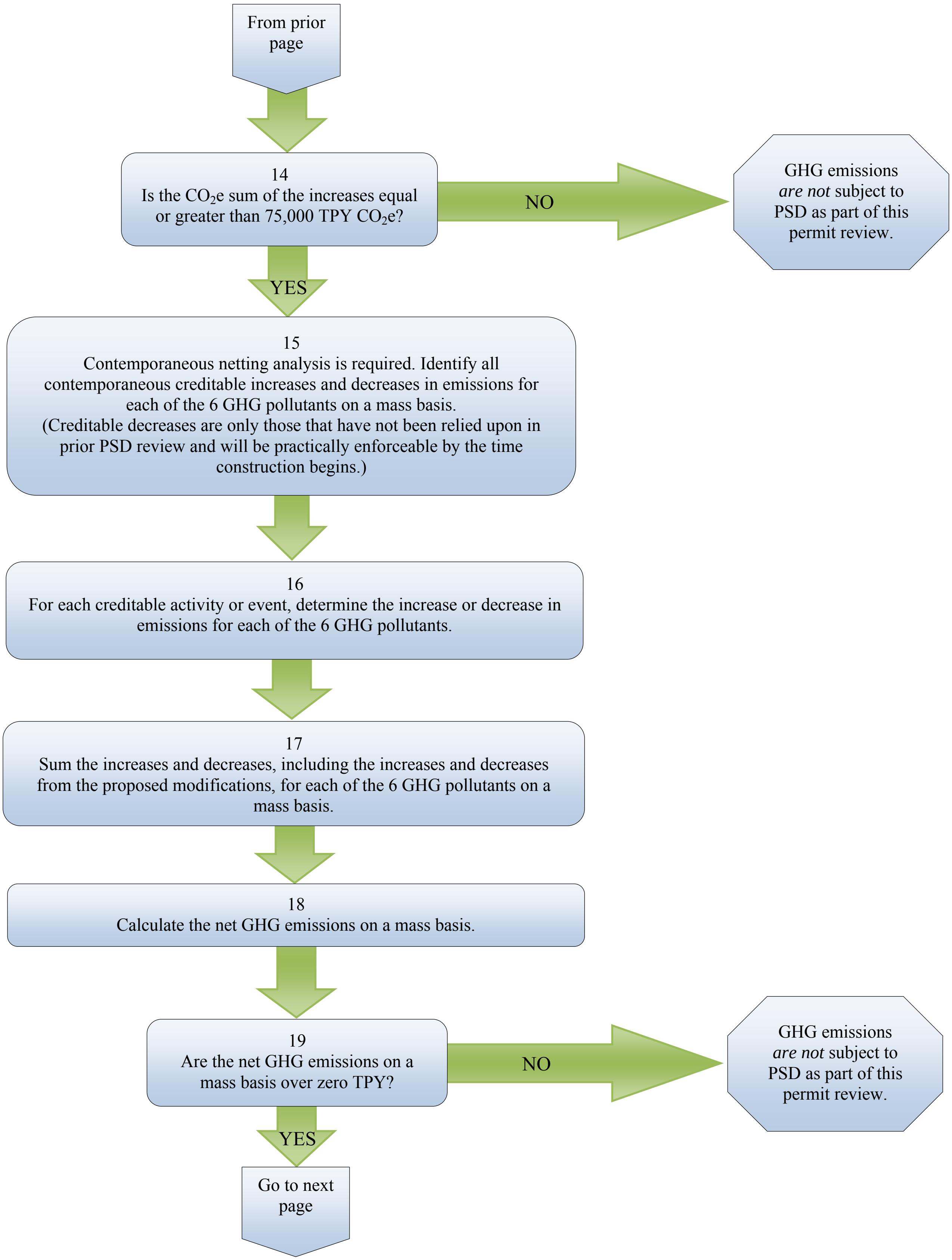

From prior page
12
Is the sum of GHG emissions increases equal to or greater than 75,000 TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
13
Contemporaneous netting analysis is required.
Identify all contemporaneous creditable increases and decreases in emissions for each of the 6 GHG pollutants on a mass basis.
(Creditable decreases are only those that have not been relied upon in prior PSD review and will be practically enforceable by the time construction begins.)
14
For each creditable activity or event, determine the increase or decrease in emissions for each of the 6 GHG pollutants on mass basis.
15
Sum the increases and decreases, including the increases and decreases from the proposed modification, for each of the 6 GHG pollutants on a mass basis.
16
Calculate the net GHG emissions on a mass basis.
Go to next page

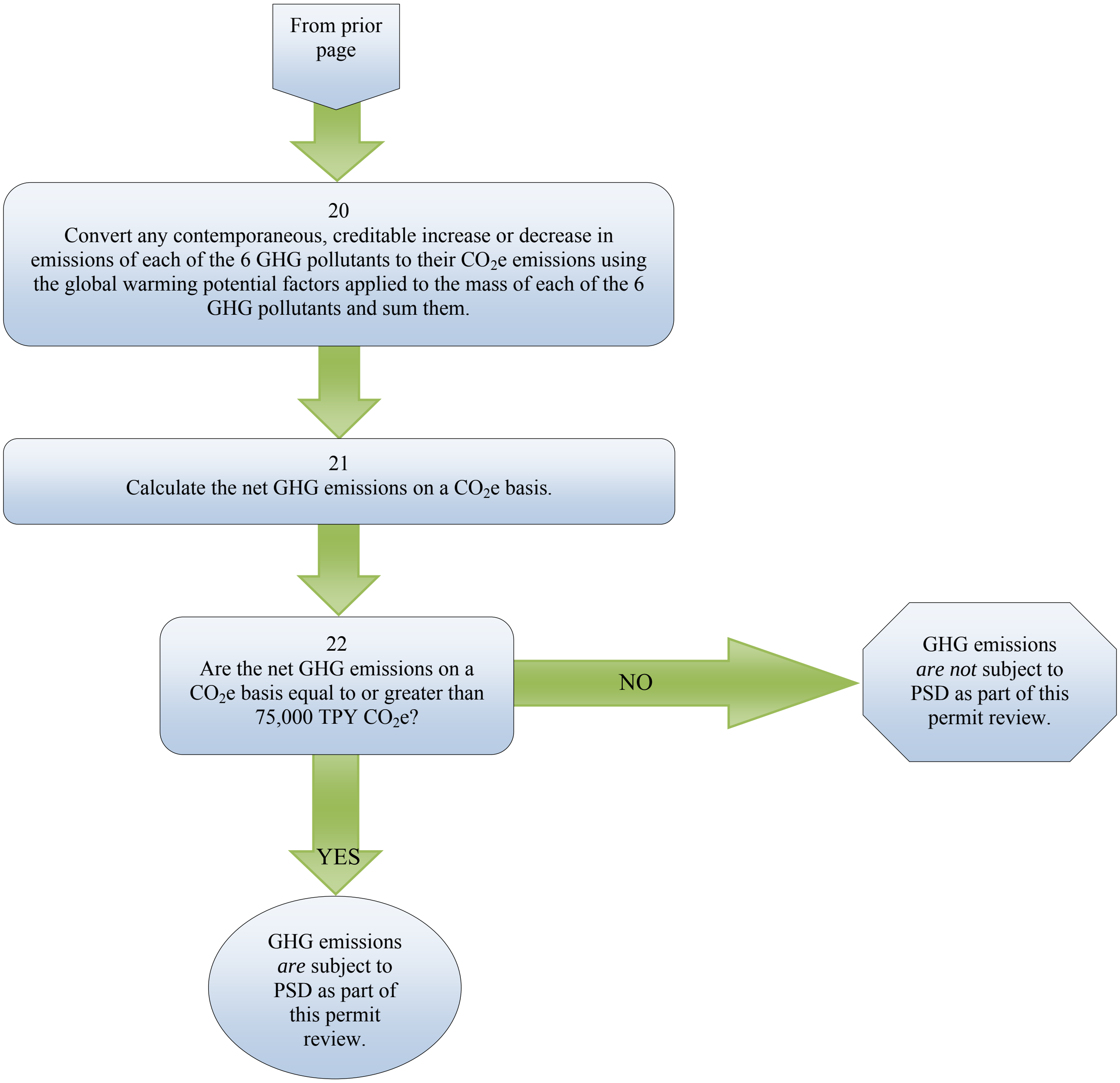

From prior page
17
Are the net GHG emissions on a mass basis over zero TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
18
Convert any contemporaneous, creditable increase or decrease in emissions of each of the 6 GHG pollutants to their CO_2e emissions using the global warming potential factors applied to the mass of each of the 6 GHG pollutants and sum them.
19
Calculate the net GHG emissions on a CO_2e basis.
20
Are the net GHG emissions on a CO_2e basis equal to or greater than 75,000 TPY CO_2e?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
GHG emissions *are* subject to PSD as part of this permit review.

Appendix D. GHG Applicability Flowchart – Modified Sources (On or after July 1, 2011)




From prior page
7
For units that are part of the modification, determine the future projected actual emissions (or PTE) in TPY for each of the 6 GHG pollutants.
8
For each unit, determine the increase or decrease in mass emissions of each of the 6 GHG pollutants by subtracting past actual emissions from future actual emissions. (For new units that are not "replacement units," future actual emissions are equal to the PTE.)
9
For each unit, sum any increase or decrease in GHG emissions on a mass basis.
10
For all units that have mass emissions increase, sum the GHG emissions on a mass basis.
11
Is the sum of GHG mass emissions increase over zero TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
12
For each unit, convert any increase or decrease in emissions of each of the 6 GHG pollutants to their CO_2e emissions using the global warming potential factors applied to the mass of each of the 6 GHG pollutants and sum them for each unit to arrive at one GHG CO_2e number for each unit.
13
Sum the GHG emissions on a CO_2e basis for all units that have an emissions increase. (Emission decreases are not considered in this step.)
Go to next page


From prior page
14
Is the CO_2e sum of the increases equal or greater than 75,000 TPY CO_2e?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
15
Contemporaneous netting analysis is required. Identify all contemporaneous creditable increases and decreases in emissions for each of the 6 GHG pollutants on a mass basis.
(Creditable decreases are only those that have not been relied upon in prior PSD review and will be practically enforceable by the time construction begins.)
16
For each creditable activity or event, determine the increase or decrease in emissions for each of the 6 GHG pollutants.
17
Sum the increases and decreases, including the increases and decreases from the proposed modifications, for each of the 6 GHG pollutants on a mass basis.
18
Calculate the net GHG emissions on a mass basis.
19
Are the net GHG emissions on a mass basis over zero TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
Go to next page


From prior page
20
Convert any contemporaneous, creditable increase or decrease in emissions of each of the 6 GHG pollutants to their CO_2e emissions using the global warming potential factors applied to the mass of each of the 6 GHG pollutants and sum them.
21
Calculate the net GHG emissions on a CO_2e basis.
22
Are the net GHG emissions on a CO_2e basis equal to or greater than 75,000 TPY CO_2e?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
GHG emissions *are* subject to PSD as part of this permit review.

Appendix E. Example of PSD Applicability for a Modified Source

Example Scenario:

- An existing stationary source is major for PSD and modifications involving GHGs may be major and possibly subject to PSD.
- The proposed modification consists of the addition of a new emissions unit (Unit #2) and a modification to existing emissions unit (Unit #1). Both units emit one or more compounds identified as a GHG.
- Emissions Unit A was added at the source 3 years ago.
- The GHG emissions used in PSD applicability analyses is a sum of the compounds emitted at the emission unit.

Unit #2 A new emissions unit with a proposed emissions **increase** of 77,000 TPY of CO_2 (1 x 77,000 TPY CO_2 = 77,000 TPY CO_2e).[134]

Unit #1 The modified existing Unit #1 will result in a CO_2 emissions **increase** of 50 TPY (1 x 50 TPY = 50 TPY CO_2e) and a CH_4 emissions **decrease** of 90 TPY (21 x 90 TPY CH_4 = 1890 TPY CO_2e). The pre- and post-change emissions are:

- Baseline actual GHG mass emissions are 400 TPY of CO_2 and 100 TPY of CH_4, which is a total of 500 TPY of GHGs on a mass basis.
- Proposed GHG emissions after the change are 460 TPY (450 TPY from CO_2, 10 TPY from CH_4), which is a 40 TPY decrease from baseline actual emissions on a mass basis.
- Baseline actual CO_2e emissions are 400 TPY CO_2e (1 x 400 TPY of CO_2) plus 2,100 TPY of CO_2e (21 x 100 TPY of CH_4) = 2500 TPY of CO_2e.
- Proposed CO_2e emissions after the change are 450 TPY of CO_2e (1 x 450 TPY of CO_2) plus 210 TPY of CO_2e (21 x 10 TPY of CH_4) = 660 TPY of CO_2e.

Unit A Three years ago, during the contemporaneous period, there was an emissions increase of 10,000 TPY CO_2 (10,000 TPY CO_2e) from the addition of a new emissions unit (Unit A) at the source. There are no other creditable emissions increases or decreases during the contemporaneous period.

Note: The source must calculate emissions changes from existing emissions units being modified (e.g., Unit #1) and in preparing that calculation, the source must compare the emission unit's baseline actual emissions to either (1) a projection of its future actual emissions; or (2) its potential to emit (PTE). See 40 CFR 52.21(b)(41)(ii). Any creditable emissions decreases from existing emissions units must be decreases in baseline actual emissions. The requirements of the PSD rules apply to these calculations and determinations as applicable.

Mass-Based Calculations

***(Step 1)** In this step, only consider emissions increases of GHGs from the proposed modification.*

Unit #2 77,000 TPY mass emissions **increase** of GHGs.

[134] For the purposes of this example, the Global Warming Potential values are from the 40 CFR Part 98 Table A-1, as of the date of this document.

Unit #1 The proposed GHG emissions are 460 TPY, which is a 40 TPY GHG mass emissions **decrease** from the baseline actual emissions of 500 TPY. The change at Unit #1 results in a **decrease** in GHG emissions and is therefore not considered in Step 1.

Increases = 77,000 TPY GHG mass emissions increase from Unit #2 is greater than zero TPY, so

Go to Step 2 and conduct contemporaneous netting

(Step 2) *In this step, include the emissions increases and decreases of GHGs from the project and all other contemporaneous and creditable emissions increases and decreases of GHGs.*

Net emissions increase = 77,000 TPY GHG mass emissions from Unit #2 minus a 40 TPY GHG decrease from Unit #1 plus a 10,000 TPY GHG increase from Unit A equals 86,960 TPY GHG mass emissions. This net emissions increase is greater than zero TPY, so

Go to the CO_2e*-based calculations*

CO_2e-Based Calculations

(Step 1) *In this step, only consider CO_2e emissions increases from the modification.*

Unit #2 77,000 TPY CO_2e emissions **increase**

Unit #1 The proposed CO_2e emissions after the modification are 660 TPY CO_2e, which is a 1,840 TPY CO_2e **decrease** from baseline actual emissions of 2,500 TPY CO_2e. Since it is a decrease, ignore the change in CO_2e emissions.

Increases = 77,000 TPY CO_2e emissions increase from Unit #2 is equal to or greater than 75,000 TPY CO_2e, so

Go to Step 2 and conduct contemporaneous netting

(Step 2) *In this step, consider all emissions increases and decreases of CO_2e from the proposed project and all other contemporaneous and creditable emissions increases and decreases of CO_2e.*

Net emissions increase = 77,000 TPY CO_2e emissions increase from Unit #2 minus 1,840 TPY CO_2e emissions decrease from Unit #1 plus a 10,000 TPY CO_2e emissions increase from Unit A equals 85,160 TPY CO_2e emissions. This net emissions increase is equal to or greater than 75,000 TPY CO_2e.

Results: The modification is both a "significant emissions increase" (Step 1) and a "significant net emissions increase" (Step 2) in both the mass and CO_2e-based calculations; therefore, the modification as proposed is major and subject to PSD for GHGs.

Appendix F. BACT Example – Natural Gas Boiler

[Disclaimer: The control options listed here and the outcomes of this example are presented for illustrative purposes only. They do not represent any specific guidance or direction from EPA relative to a BACT determination for this type of source.]

Project Scope: The permit applicant is proposing to install, at an existing PSD major source, a new 250 MMBtu/hour natural gas-fired boiler. The project's emissions increase is in excess of 75,000 TPY CO_2e and the permit will be issued in March 2011, so the project is subject to BACT for GHGs under Step 1 of the Tailoring Rule. For the sake of simplicity, this example focuses on the section of the BACT analysis for GHG emissions from the project.

The top-down BACT determination is carried out in the following five steps:

Step 1: Identifying all available controls

For purposes of this example, assume that the permit application listed the following available controls in the GHG BACT analysis:

- Boiler Annual Tune-up – Once a year the boiler is tuned for optimal thermal efficiency.
- Boiler Oxygen Trim Control – Stack oxygen level is monitored and the inlet air flow is adjusted for optimal thermal efficiency.
- Use of an Economizer – A heat exchanger is used to transfer some of the heat from the boiler exhaust gas to the incoming boiler feedwater. Preheating the feedwater in this way reduces boiler heating load, increases its thermal efficiency and reduces emissions.
- Boiler Blowdown Heat Recovery – Periodically or continuously, some water in the boiler is removed as a means of avoiding the build-up of water impurities in the boiler. A heat exchanger is used to transfer some of the heat in the hot blowdown water for preheating feedwater. This increases the boiler's thermal efficiency.
- Condensate Recovery – As the boiler steam is used in the heat exchanger, it condenses. When hot condensate is returned to the boiler as feedwater, the boiler heating load is reduced and the thermal efficiency increases.

As would be appropriate under EPA's guidelines for Step 1 of the BACT process, the permitting authority asked the applicant to expand the analysis to consider an air preheater (which recovers heat in the boiler exhaust gas to preheat combustion air). Accordingly, at this stage in this example, the permit applicant and permitting authority identified six control measures.

Further, a public comment was received arguing that the analysis should include a combined cycle natural gas-fired turbine that is more efficient than the proposed boiler. Since the application explains that a boiler is necessary to fulfill the fundamental business purpose of providing process steam (and not generating electricity) and because a varying steam demand requires the ability to startup and shutdown the boiler quickly (due to the fluctuating operational demands of the facility, as substantiated in the application), the permitting authority declined to list the option in Step 1 of the BACT analysis on the grounds it would redefine the source. The permitting authority thoroughly documented this decision in its response to comments.

Step 2: Eliminating technically infeasible options

At this stage of the review, the permit applicant and the permitting authority examine all options for technical feasibility. For this example, the permitting authority determined that the seven controls identified are technically feasible because nothing in the record showed that any of these options was not demonstrated or available or applicable to this type of source.

Step 3: Evaluation and ranking of controls by their effectiveness.

At this step, the permit applicant and permitting authority need to select a measure of effectiveness to compare and rank the options. Assume in this example that the applicant ranked control measures for the boiler based on their impact on the thermal efficiency of the boiler, after finding that thermal efficiency was a useful indicator of CO_2 control efficiency because fuel use is directly related to CO_2 emissions for the boiler and the impact of control measures.

The permit applicant completed the control effectiveness analysis showing that the most effective single measure is oxygen trim control. The applicant's analysis also showed that the use of an air preheater was no more effective than an economizer in recovering exhaust heat, and so the applicant narrowed the review to the economizer only. In this example, the applicant's analysis next considered the effectiveness of the boiler controls in combinations and found that the most effective combination of measures is the use of four measures – oxygen trim control, an economizer, condensate recovery and blowdown heat recovery – which was approved by the permitting authority.

Step 4: Evaluating the most effective controls and documenting results

In this step, the permit applicant completed an analysis of the cost effectiveness of measures and combinations of measures, expressed as $/ton of GHG reduced, as well as an incremental cost effectiveness analysis. In this example, the applicant found that, given the size and other characteristics of this facility, the packages including boiler blowdown heat recovery was not cost effective (as an incremental measure compared to cost born by similar facilities) and the next most effective combination of measures for the boiler was the use of oxygen trim control, an economizer and condensate recovery. The applicant documented this decision in the permitting record and the permitting authority agreed.

Significant energy and environmental impacts are also considered in this step. In this example, the record also showed that the recovery and reuse of condensate would reduce the use of boiler treatment chemicals and the generation of related waste and thus would reduce the amount of water going to wastewater treatment at the site. Since condensate recovery was still in consideration, this information provided additional record support continuing to consider condensate recovery part of the technology option.

Step 5: Selecting BACT

With the analysis and record complete, the permitting authority determines BACT in this last step. In this example, the permitting authority determined, and the record showed, that BACT for GHGs from the proposed facility was the combination of oxygen trim control, an economizer and condensate recovery for the boiler, along with a high transfer efficiency design for the heat exchanger. Accordingly, the permitting authority included the following permit terms in the permit:

- Emission limit expressed in lbs of CO_2e emissions per pound of steam produced, averaged over 30 day rolling periods;
- CO_2e emissions are to be determined based on metered natural gas use and the application of standard emission factors;
- Steam production determined from a gauge on the outlet of the boiler;
- In addition, there would be a requirement to install the boiler as described in the application and BACT determination;
- There would be a requirement to implement a preventive maintenance program for the air to fuel ratio controller of the boiler; and
- A requirement for periodic maintenance and calibration of the natural gas meter and the steam flow analyzer.

Appendix G. BACT Example – Municipal Solid Waste Landfill

[Disclaimer: The control options listed here and the outcomes of this example are presented for illustrative purposes only. They do not represent any specific guidance or direction from EPA relative to a BACT determination for this type of source.]

Project Scope: The permit applicant proposes to build a new, large municipal solid waste landfill. As the solid waste in a landfill decomposes, landfill gas (composed of methane, carbon dioxide, and trace amounts of organic compounds) is formed. The application shows that the PTE of the landfill expressed as CO_2e emissions is in excess of 100,000 TPY. The permit will be issued after June 2011, so BACT will apply to the GHG emissions under Step 2 of the Tailoring Rule. For the sake of simplicity, this example focuses on the section of the BACT analysis for the capture and control of the landfill gas from the project.

The permit applicant and reviewing authority conduct their BACT determination using the five steps of the top-down processes as follows:

Step 1: Identifying all available controls

The permit applicant and permitting authority agree that the BACT review for a landfill logically has two elements: the capture of the landfill gas and the control of emissions of that gas. In this example, there is an existing NSPS (Part 60 Subpart WWW) applicable to non-methane organic compounds (NMOC) emissions from Municipal Solid Waste (MSW) landfills, which addresses the capture and control of landfill gas. While the NSPS addresses a different component of the emissions than GHGs, the permit applicant and the permitting authority determine that the NSPS is a useful starting point for a GHG BACT determination since it has detailed requirements for the design and operation of the gas collection system.

For capture of the landfill gas, the application uses compliance with the NSPS as the starting point. For control, the applicant identified the following three NSPS options as a starting point for the BACT determination:

- venting to an on-site flare,
- use of the gas in on-site internal combustion engines to generate electricity, or
- treatment of the gas for delivery to a natural gas pipeline.

The applicant did not identify or propose any alternative control options in the application, and none were suggested in public comments. However, the permitting authority did ask the applicant to expand the review to consider two other control measures: (1) a requirement to collect and control landfill gas earlier in the life of the landfill than is specified in the NSPS, and (2) the use of a gas turbine to generate power rather than internal combustion engines.

At this stage, there are two control measures listed for gas capture (NSPS compliant system and a NSPS system with earlier gas collection and treatment) and four control options listed for the control of the landfill gas that is collected (flaring, fueling engines, fueling a gas turbine, and treatment and routing of the gas to a pipeline).

Step 2: Eliminating technically infeasible options

At this stage of the review, the applicant and permitting authority assess the technical feasibility of each option. In this example, the applicant demonstrated that the volume of gas from the proposed facility would be inadequate to fuel a commercially available gas turbine. The permitting authority reviewed the record regarding the technical infeasibility for the gas turbine option, found it was adequate, and accepted elimination of that option from further consideration.

Step 3: Evaluation and ranking of controls by their effectiveness

At this step, the permit applicant and permitting authority need to determine a metric for ranking the control effectiveness of the options under consideration. In this case, the application used total CO_2e emissions over the life of the landfill, based on the current business plan and design, as the effectiveness indicator. The applicant explained that the CO_2e emissions estimates in their application reflected the direct emissions of GHGs and the CO_2 produced for the options where that gas was combusted on site. The application also considered combinations of capture systems and controls for overall effectiveness. The record showed that early capture of gas and conversion of the gas to pipeline quality for export were likely to be the most effective combination, from a PSD perspective, given that the maximum amount of gas would be captured and most of the gas would not be combusted on site. The record also showed that flaring and the use of engines were similar in their control of overall on-site GHG emissions, with both controls reducing methane emissions significantly while generating relatively small on-site CO_2 emissions in the process.

Step 4: Evaluating the most effective controls and documenting results

In this step, the applicant completed an analysis of the cost effectiveness of control measures, expressed as $/ton of GHG reduced, and also determined the incremental cost effectiveness. In this example, the applicant's analysis first found that conversion of gas to pipeline quality was not cost effective, explaining that this control option would more than double the overall cost of the project since the landfill was far from an existing pipeline, and the permitting authority agreed that it should be eliminated for further consideration in the BACT analysis. The record also showed that the NSPS system with early collection was cost effective in both the flare and the engines case. There was also evidence in the record showing that the flare was more cost effective because revenue from the sale of power from use of engines was too little to offset the added cost of the engines and a power transmission line.

The applicant and permitting authority also considered the collateral energy and environmental impacts of the options. In this example, the application noted that there was a positive environmental impact from the use of a flare because NO_X emissions for a flare would be lower than those for the engines. Some public comments identified positive energy and environmental offsite impacts arising from the fact that using landfill gas to generate electricity would displace some other offsite energy generation and associated emissions. In responding to the comments, the permitting authority determined that this benefit outweighed the lower NO_X emissions from the flare. The permit record also demonstrated that the use of engines or a flare would have nearly equal CO_2e control effectiveness. Accordingly, the permitting authority found that the environmental benefits arising from the engines-based system outweighed the flare's cost effectiveness and environmental benefits of lower NO_X emissions.

Step 5: Selecting BACT

The permitting authority determines BACT in this last step. In this example, the permitting authority determined that BACT for the proposed facility was NSPS compliance with early implementation of the capture and control system with engines combusting the landfill gas to generate electricity. Accordingly, the permitting authority included the following permit terms in the permit:

- Compliance with the landfill design and operation requirements of the applicable NSPS with a revised condition for earlier capture and control of the gas.
- A requirement to combust the collected gas in engines with the creation and use of an O&M plan for the engines to assure that they operate efficiently.

Appendix H. BACT Example – Petroleum Refinery Hydrogen Plant

[Disclaimer: The control options listed here and the outcomes of this example are presented for illustrative purposes only. They do not represent any specific guidance or direction from EPA relative to a BACT determination for this type of source.]

Project Scope:
Petroleum refineries produce and utilize hydrogen in order to convert crude oil to finished products. In this example, a permit applicant proposes a modification project to expand the hydrogen production and hydrotreating capacity of an existing major source refinery. The application submitted by the permit applicant shows that the project has a significant emissions increase and a significant net emissions increase on both a CO_2e basis and a mass basis. The permitting authority will issue the permit in October 2011, so PSD is triggered for GHGs in Step 2 of the Tailoring Rule. For simplicity, this example addresses the GHG BACT analysis for the new hydrogen plant only.

Accordingly to the application, the proposed project utilizes the most common method of producing hydrogen at a refinery, the steam methane reforming (SMR) process. In SMR, methane and steam are reacted via a catalyst to produce hydrogen and CO. The reaction is endothermic and the necessary heat is provided in a gas-fired reformer furnace. The CO generated by the initial SMR reaction further reacts with the steam to generate hydrogen and CO_2. The hydrogen is then separated from the CO_2 and other impurities. In this example, the application shows that the purification is done using a Pressure Swing Adsorption Unit. The permit applicant proposes to use the offgas from that step (containing some hydrogen, CO_2, and other gases) as part of the fuel for the reformer furnace.

The top-down BACT determination is carried out in the following five steps:

Step 1: Identifying all available controls

Assume for purposes of this example that the permit application lists the following control options for GHG emissions:

- Furnace Air/Fuel Control – An oxygen sensor in the furnace exhaust is to be used to control the air and fuel ratio in the furnace on a continuous basis for optimal energy efficiency.
- Waste Heat Recovery – The overall thermal efficiency is to be optimized through the recovery of heat from both the furnace exhaust and the process streams to preheat the furnace combustion air, to preheat the feed to the furnace and to produce steam for use in the process and elsewhere in the refinery.
- CO_2 Capture and Storage – Capture and compression, transport, and geologic storage of the CO_2. (Some refineries isolate hydrogen reformer CO_2 for sale but that is not a part of this example project.)

The permitting authority did not require the applicant to identify any alternative control options beyond those in the application, and none were suggested in public comments.

Step 2: Eliminating technically infeasible options

At this stage of the review, the permit applicant and the permitting authority examine the control options for technical feasibility. In this example, the permitting record shows that all three controls are technically feasible because there is no evidence that any of these options are not demonstrated or available or applicable to this type of source.

Step 3: Evaluation and ranking of controls by their effectiveness.

At this step, the permit applicant and permitting authority need to select a measure of effectiveness to compare and rank the options. In this example, the applicant ranked control measures for the hydrogen plant based on the GHG emissions per unit of hydrogen produced. The applicant and the permitting authority agreed that such an output-based indicator was a good way to capture the overall effect of multiple energy efficiency measures used in the design of a complex process such as this.

The permit applicant then completed a control effectiveness analysis, in which benchmarking data on the energy efficiency and GHG emissions of recently installed hydrogen plants was provided. The applicant showed that by incorporating various heat recovery measures this hydrogen plant would be a lower emitter (on an output basis) than similar new plants, and the permitting authority concurred in that determination. The applicant's analysis considered the effectiveness of each individual measure and combinations of measures. In this case, the applicant determined that the most effective combination was one in which all three options were included.

Step 4: Evaluating the most effective controls and documenting results

In this step, the permit applicant completed an analysis of the cost effectiveness of measures and combinations of measures, expressed as $/ton of GHG reduced. The applicant also determined the incremental cost effectiveness. In this example, the information supplied by the applicant demonstrated that the transport and sequestration of CO_2 would not be cost effective because the nearest prospective location for sequestration was more than 500 miles away and there was not an existing pipeline or other suitable method for CO_2 transport between the refinery and the sequestration location. Accordingly, the record showed that the cost of transport was significant in comparison to the amount of CO_2 to be sequestered and the cost of the project overall. Although the permitting authority affirmed this determination, in responding to public comments on the issue, the permitting authority did note that in circumstances in which a refinery was located near an oil field that used CO_2 injection for enhanced recovery, the cost for transport and sequestration would likely be in a range that would not exclude the transport control option from the list of technologies that would continue to be considered in the BACT analysis.

Permit applicants and permitting authorities also consider other significant energy and environmental impacts in this step. In this case, none were presented in the application, and the only significant public comment on the issue was addressed by the permitting authority, as noted above.

Step 5: Selecting BACT

With the analysis and record complete, the permitting authority determines BACT. In this example, the permitting authority determined that BACT was a combination of furnace combustion control and integrated waste heat recovery. Accordingly, the permitting authority included the following permit terms in the permit:

- Emission limit in pounds of CO_2e emitted per pound of hydrogen produced, averaged over rolling 30-day periods.
- CO_2e emissions would be determined by metering natural gas sent to the hydrogen plant. With prior approval of the permitting authority, the emissions could be adjusted for excess fuel gas sent to other parts of the refinery. A separate meter and fuel analysis would be needed to get that credit.
- Hydrogen production would be metered.
- The heat recovery systems would need to be installed as described in the application.
- There would need to be a written program for calibration and maintenance of meters.

Appendix I. Resources for GHG Emission Estimation

The following are a number of methods that are traditionally used to estimate PTE from sources and relevant emissions units:

- 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.

These approaches remain relevant for GHG emissions calculations and serve as the fundamental approaches to estimating emissions for permitting applications. For example, direct measurements methods such as continuous emissions monitors (CEMs) would continue to be a preferred means to form the starting point basis for estimating emissions from GHG emissions units. However, because GHG emissions historically have not been subject to regulation under air permitting programs, and there are unique GHG emission source categories, there is not as widespread representation or long-term experience with GHG estimation techniques and measurement methods as there is for conventional pollutants under the above approaches. The purpose of this section is to identify additional references and resources that may be useful when evaluating GHG emission sources and deciding which estimation methods to use.[135]

Mandatory Reporting of Greenhouse Gases. This final rule was issued on October 30, 2009 (74 FR 56260), and established GHG reporting requirements for all sectors of the economy and should be considered a primary reference for sources and permitting authorities in estimating GHG emissions and establishing measurement techniques when preparing or processing permit applications. The rule includes procedures for estimating GHG emissions from the source categories that are responsible for the majority of stationary source GHG emissions in the U.S. The procedures identify where applications of direct measurement techniques are viable and describes emission factor and mass-balance based approaches where direct measurement techniques are not applicable or available.

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[135] The exclusion of a source or emission unit category from these sources does not imply that such sources or emissions units are excluded from permitting requirements. For example, as of the date of this publication CO_2 from biomass combustion is not included in determining applicability under the mandatory reporting rule, but is included in determining applicability under both PSD and title V programs as described in the Tailoring Rule. Also, there are not methods identified for all possible GHG emitting sources and units in the current mandatory reporting rule.

While the GHG reporting rule is focused on estimating and reporting *actual* emissions from source categories, the basic approaches can be used to estimate a source's PTE when correctly adjusted to reflect future conditions and operating parameters. Since many of the affected GHG source categories and emissions units have been or will be subject to permitting requirements for conventional, non-GHG pollutants, sources should use similar adjustments to fuel throughput, activity data, and emissions for determining PTE for GHG that have been used in existing PSD and title V guidance for those units and which are applied on a case-by-case basis depending on specific operating parameters for the affected sources.

Other reference sources that may prove useful to sources and permitting authorities in identifying, characterizing and estimating emissions from GHG emission sources include the following:

- **ENERGY STAR Industrial Sector Energy Guides and Plant Energy Performance Indicators (benchmarks)**
  http://www.energystar.gov/epis

- **US EPA National Greenhouse Gas Inventory**
  http://epa.gov/climatechange/emissions/usinventoryreport.html

- **EPA's Climate Leaders Protocols**
  http://www.epa.gov/stateply/index.html

- **EPA's Voluntary Partnerships for GHG Reductions:**
  - Landfill Methane Outreach Program (http://www.epa.gov/lmop/)
  - CHP Partnership Program (http://www.epa.gov/chp)
  - Green Power Partnership (http://www.epa.gov/greenpower)
  - Coalbed Methane Outreach Program (http://www.epa.gov/cmop/index.html)
  - Natural Gas STAR Program (http://www.epa.gov/gasstar/index.html)
  - Voluntary Aluminum Industrial Partnership:
    http://www.epa.gov/highgwp/aluminum-pfc/index.html

- **SF Emission Reduction Partnership for the Magnesium Industry**
  http://www.epa.gov/highgwp/magnesium-sf6/index.html

- **PFC Reduction/Climate Partnership for the Semiconductor Industry**
  http://www.epa.gov/highgwp/semiconductor-pfc/index.html

- **Landfill Gas Emissions Model**
  User's Guide: http://www.epa.gov/ttncatc1/dir1/landgem-v302-guide.pdf

- **Estimation Methodologies for Biogenic Emissions from Solid Waste Disposal, Wastewater Treatment, and Ethanol Fermentation**
  http://www.epa.gov/ttn/chief/efpac/ghg/GHG_Biogenic_Report_revised_Dec1410.pdf

Appendix J. Resources for GHG Control Measures

The following are several information sources to consider when looking for available GHG control measures when conducting a BACT analysis.

- **EPA's GHG Mitigation Measures Database**
  http://www.epa.gov/nsr/ghgpermitting.html

- **EPA's Sector GHG Control White Papers**
  http://www.epa.gov/nsr/ghgpermitting.html

- **EPA's RACT/BACT/LAER Clearinghouse (RBLC)**
  http://cfpub.epa.gov/rblc/

- **ENERGY STAR Guidelines for Energy Management**
  http://www.energystar.gov/guidelines

- **ENERGY STAR Industrial Sector Energy Guides**
  http://www.energystar.gov/epis

- **EPA's Climate Leaders Protocols**
  http://www.epa.gov/stateply/index.html

- **Report of the Interagency Task Force on Carbon Capture and Storage**
  http://www.epa.gov/climatechange/policy/ccs_task_force.html

- **EPA's Lean and Energy Toolkit**
  http://www.epa.gov/lean/toolkit/LeanEnergyToolkit.pdf

- **EPA's Voluntary Partnerships for GHG Reductions:**
  - Landfill Methane Outreach Program (http://www.epa.gov/lmop/)
  - CHP Partnership Program (http://www.epa.gov/chp)
  - Green Power Partnership (http://www.epa.gov/greenpower)
  - Coalbed Methane Outreach Program (http://www.epa.gov/cmop/index.html)
  - Natural Gas STAR Program (http://www.epa.gov/gasstar/index.html)
  - Voluntary Aluminum Industrial Partnership:
    http://www.epa.gov/highgwp/aluminum-pfc/index.html

- **SF Emission Reduction Partnership for the Magnesium Industry**
  http://www.epa.gov/highgwp/magnesium-sf6/index.html

- **PFC Reduction/Climate Partnership for the Semiconductor Industry**
  http://www.epa.gov/highgwp/semiconductor-pfc/index.html

- **DOE's Industrial Technologies Program (Best Practices)**
  http://www1.eere.energy.gov/industry/bestpractices/

Additionally, the following are several information sources that may be helpful when including benchmarking as part of a BACT analysis.

- **EPA Energy Star Industrial Energy Management Information Center**
  http://www.energystar.gov/index.cfm?c=industry.bus_industry_info_center

- **DOE Industrial Technologies Program**
  http://www1.eere.energy.gov/industry/

- **Lawrence Berkeley National Laboratory Industrial Energy Analysis Program**
  http://industrial-energy.lbl.gov/

- **European Union Energy Efficiency Benchmarks**
  http://ec.europa.eu/environment/climat/emission/benchmarking_en.htm

In addition to the above sources of information, once permitting authorities gain experience with GHG BACT determinations, useful information on GHG permitting decisions will be present in EPA's RBLC and Control Technology Center.

Appendix K. Calculating Cost Effectiveness for BACT

The following excerpt is from the Draft 1990 NSR Workshop Manual (pages B.36-B.44)

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.

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.

Average Cost Effectiveness

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).

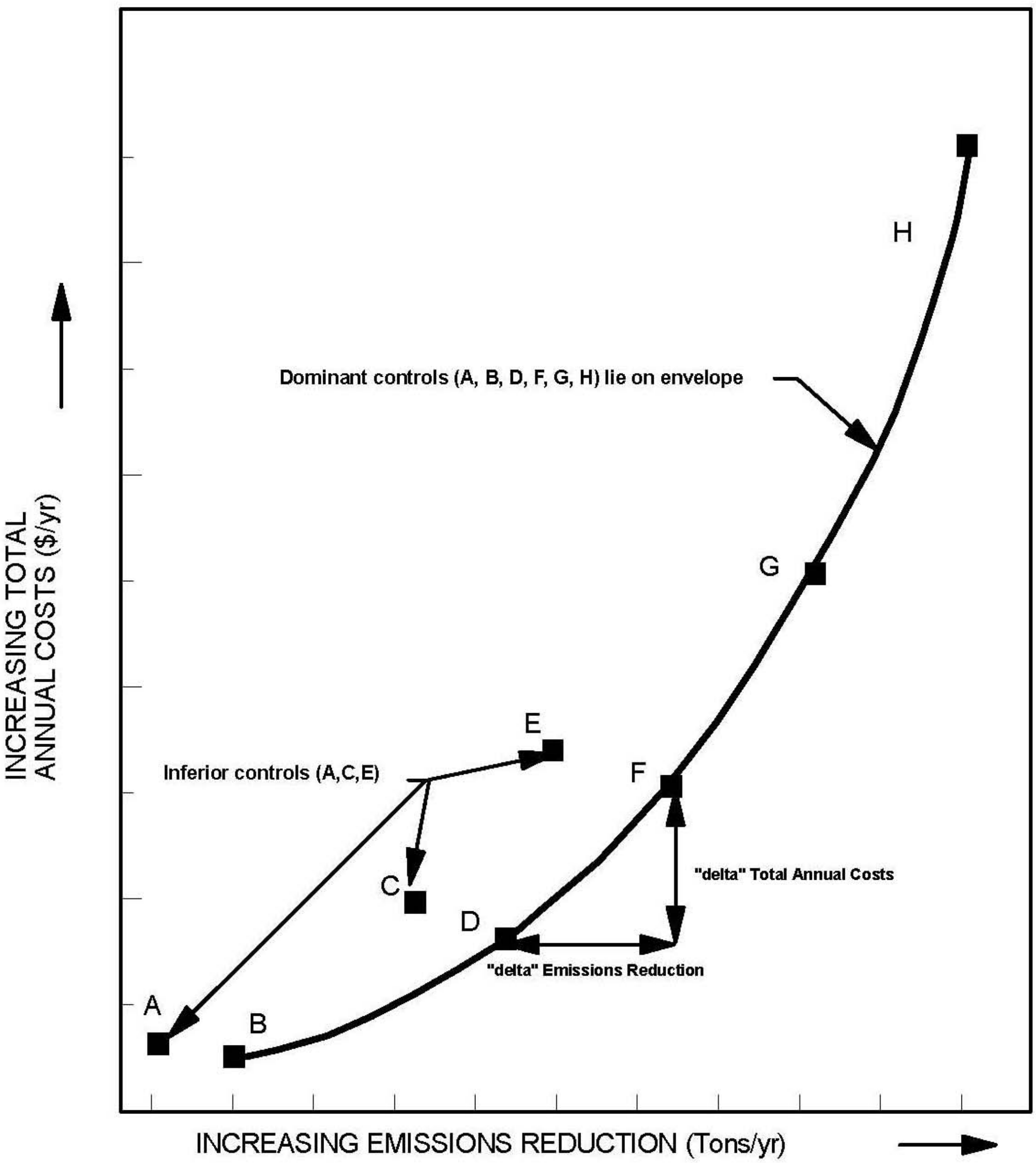

Figure B-1. LEAST-COST ENVELOPE

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 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.

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