

1ST NOTICE VERSION

JCAR350225-0818507r01

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3 CHAPTER I: POLLUTION CONTROL BOARD
4 SUBCHAPTER c: EMISSION STANDARDS AND LIMITATIONS
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127	225.APPENDIX A	Specified EGUs for Purposes of the CPSSubpart F (Midwest Generation's
128		Coal-Fired Boilers as of July 1, 2006)
129	225.APPENDIX B	Continuous Emission Monitoring Systems for Mercury

130
 131 AUTHORITY: Implementing and authorized by Section 27 of the Environmental Protection Act
 132 [415 ILCS 5/27].
 133

134 SOURCE: Adopted in R06-25 at 31 Ill. Reg. 129, effective December 21, 2006; amended in
 135 R06-26 at 31 Ill. Reg. 12864, effective August 31, 2007; amended in R09-10 at 33 Ill. Reg.
 136 _____, effective _____.
 137

138 SUBPART A: GENERAL PROVISIONS
 139

140 **Section 225.120 Abbreviations and Acronyms**
 141

142 Unless otherwise specified within this Part, the abbreviations used in this Part must be the same
 143 as those found in 35 Ill. Adm. Code 211. The following abbreviations and acronyms are used in
 144 this Part:
 145

Act	Environmental Protection Act [415 ILCS 5]
ACI	activated carbon injection
<u>AETB</u>	<u>Air Emission Testing Body</u>
Agency	Illinois Environmental Protection Agency
Btu	British thermal unit
CAA	Clean Air Act (42 USC 7401 et seq.)
CAAPP	Clean Air Act Permit Program
CAIR	Clean Air Interstate Rule
CASA	Clean Air Set-Aside
CEMS	continuous emission monitoring system
CO ₂	carbon dioxide
CPS	Combined Pollutant Standard
CGO	converted gross electrical output
<u>CRM</u>	<u>certified reference materials</u>
CUTE	converted useful thermal energy
<u>DAHS</u>	<u>data acquisition and handling system</u>
<u>dscm</u>	<u>dry standard cubic meters</u>
EGU	electric generating unit
ESP	electrostatic precipitator
FGD	flue gas desulfurization
<u>fpm</u>	<u>feet per minute</u>
GO	gross electrical output
GWh	gigawatt hour
HI	heat input
<u>Hg</u>	<u>mercury</u>
hr	hour
<u>ISO</u>	<u>International Organization for Standardization</u>

kg	kilogram
lb	pound
MPS	Multi-Pollutant Standard
<u>MSDS</u>	<u>Material Safety Data Sheet</u>
MW	megawatt
MWe	megawatt electrical
MWh	megawatt hour
NAAQS	National Ambient Air Quality Standards
<u>NIST</u>	<u>National Institute of Standards and Technology</u>
NO _x	nitrogen oxides
<u>NTRM</u>	<u>NIST Traceable Reference Material</u>
NUSA	New Unit Set-Aside
ORIS	Office of Regulatory Information Systems
O ₂	oxygen
PM _{2.5}	particles less than 2.5 micrometers in diameter
<u>QA</u>	<u>quality assurance</u>
<u>QC</u>	<u>quality certification</u>
RATA	relative accuracy test audit
<u>RGFM</u>	<u>reference gas flow meter</u>
SO ₂	sulfur dioxide
SNCR	selective noncatalytic reduction
TTBS	Temporary Technology Based Standard
TCGO	total converted useful thermal energy
UTE	useful thermal energy
USEPA	United States Environmental Protection Agency
yr	year

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(Source: Amended at 33 Ill. Reg. _____, effective _____)

Section 225.130 Definitions

The following definitions apply for the purposes of this Part. Unless otherwise defined in this Section or a different meaning for a term is clear from its context, the terms used in this Part have the meanings specified in 35 Ill. Adm. Code 211.

"Agency" means the Illinois Environmental Protection Agency. [415 ILCS 5/3.105]

"Averaging demonstration" means, with regard to Subpart B of this Part, a demonstration of compliance that is based on the combined performance of EGUs at two or more sources.

162 "Base Emission Rate" means, for a group of EGUs subject to emission standards
 163 for NO_x and SO₂ pursuant to Section 225.233, the average emission rate of NO_x or
 164 SO₂ from the EGUs, in pounds per million Btu heat input, for calendar years 2003
 165 through 2005 (or, for seasonal NO_x, the 2003 through 2005 ozone seasons), as
 166 determined from the data collected and quality assured by the USEPA, pursuant
 167 to the 40 CFR 72 and 96 federal Acid Rain and NO_x Budget Trading Programs,
 168 for the emissions and heat input of that group of EGUs.

169
 170 "*Board*" means the Illinois Pollution Control Board. [415 ILCS 5/3.130]
 171

172 "Boiler" means an enclosed fossil or other fuel-fired combustion device used to
 173 produce heat and to transfer heat to recirculating water, steam, or other medium.
 174

175 "Bottoming-cycle cogeneration unit" means a cogeneration unit in which the
 176 energy input to the unit is first used to produce useful thermal energy and at least
 177 some of the reject heat from the useful thermal energy application or process is
 178 then used for electricity production.
 179

180 "CAIR authorized account representative" means, for the purpose of general
 181 accounts, a responsible natural person who is authorized, in accordance with 40
 182 CFR 96, subparts BB, FF, BBB, FFF, BBBB, and FFFF to transfer and otherwise
 183 dispose of CAIR NO_x, SO₂, and NO_x Ozone Season allowances, as applicable,
 184 held in the CAIR NO_x, SO₂, and NO_x Ozone Season general account, and for the
 185 purpose of a CAIR NO_x compliance account, a CAIR SO₂ compliance account, or
 186 a CAIR NO_x Ozone Season compliance account, the CAIR designated
 187 representative of the source.
 188

189 "CAIR designated representative" means, for a CAIR NO_x source, a CAIR SO₂
 190 source, and a CAIR NO_x Ozone Season source and each CAIR NO_x unit, CAIR
 191 SO₂ unit and CAIR NO_x Ozone Season unit at the source, the natural person who
 192 is authorized by the owners and operators of the source and all such units at the
 193 source, in accordance with 40 CFR 96, subparts BB, FF, BBB, FFF, BBBB, and
 194 FFFF as applicable, to represent and legally bind each owner and operator in
 195 matters pertaining to the CAIR NO_x Annual Trading Program, CAIR SO₂ Trading
 196 Program, and CAIR NO_x Ozone Season Trading Program, as applicable. For any
 197 unit that is subject to one or more of the following programs: CAIR NO_x Annual
 198 Trading Program, CAIR SO₂ Trading Program, CAIR NO_x Ozone Season Trading
 199 Program, or the federal Acid Rain Program, the designated representative for the
 200 unit must be the same natural person for all programs applicable to the unit.
 201

202 "Coal" means any solid fuel classified as anthracite, bituminous, subbituminous,
 203 or lignite by the American Society for Testing and Materials (ASTM) Standard

204 Specification for Classification of Coals by Rank D388-77, 90, 91, 95, 98a, or 99
205 (Reapproved 2004).

206
207 "Coal-derived fuel" means any fuel (whether in a solid, liquid or gaseous state)
208 produced by the mechanical, thermal, or chemical processing of coal.

209
210 "Coal-fired" means:

211
212 For purposes of ~~Subpart~~Subparts B and F, or for purposes of allocating
213 allowances under Sections 225.435, 225.445, 225.535, and 225.545,
214 combusting any amount of coal or coal-derived fuel, alone or in
215 combination with any amount of any other fuel, during a specified year;

216
217 Except as provided above, combusting any amount of coal or coal-derived
218 fuel, alone or in combination with any amount of any other fuel.

219
220 "Cogeneration unit" means, for the purposes of Subparts C, D, and E, a stationary,
221 fossil fuel-fired boiler or a stationary, fossil fuel-fired combustion turbine of
222 which both of the following conditions are true:

223
224 It uses equipment to produce electricity and useful thermal energy for
225 industrial, commercial, heating, or cooling purposes through the sequential
226 use of energy; and

227
228 It produces either of the following during the 12-month period beginning
229 on the date the unit first produces electricity and during any subsequent
230 calendar year after that in which the unit first produces electricity:

231
232 For a topping-cycle cogeneration unit, both of the following:

233
234 Useful thermal energy not less than five percent of total
235 energy output; and

236
237 Useful power that, when added to one-half of useful
238 thermal energy produced, is not less than 42.5 percent of
239 total energy input, if useful thermal energy produced is 15
240 percent or more of total energy output, or not less than 45
241 percent of total energy input if useful thermal energy
242 produced is less than 15 percent of total energy output; or

243
244 For a bottoming-cycle cogeneration unit, useful power not less
245 than 45 percent of total energy input.

246

247 "Combined cycle system" means a system comprised of one or more combustion
248 turbines, heat recovery steam generators, and steam turbines configured to
249 improve overall efficiency of electricity generation or steam production.

250

251 "Combustion turbine" means:

252

253 An enclosed device comprising a compressor, a combustor, and a turbine
254 and in which the flue gas resulting from the combustion of fuel in the
255 combustor passes through the turbine, rotating the turbine; and

256

257 If the enclosed device described in the above paragraph of this definition
258 is combined cycle, any associated duct burner, heat recovery steam
259 generator and steam turbine.

260

261 "Commence commercial operation" means, for the purposes of ~~Subpart~~Subparts B
262 and F of this Part, with regard to an EGU that serves a generator, to have begun to
263 produce steam, gas, or other heated medium used to generate electricity for sale or
264 use, including test generation. Such date must remain the unit's date of
265 commencement of operation even if the EGU is subsequently modified,
266 reconstructed or repowered. For the purposes of Subparts C, D and E,
267 "commence commercial operation" is as defined in Section 225.150.

268

269 "Commence construction" means, for the purposes of Section 225.460(f),
270 225.470, 225.560(f), and 225.570, that the owner or owner's designee has
271 obtained all necessary preconstruction approvals (e.g., zoning) or permits and
272 either has:

273

274 Begun, or caused to begin, a continuous program of actual on-site
275 construction of the source, to be completed within a reasonable time; or

276

277 Entered into binding agreements or contractual obligations, which cannot
278 be cancelled or modified without substantial loss to the owner or operator,
279 to undertake a program of actual construction of the source to be
280 completed within a reasonable time.

281

282 For purposes of this definition:

283

284 "Construction" shall be determined as any physical change or
285 change in the method of operation, including but not limited to
286 fabrication, erection, installation, demolition, or modification of
287 projects eligible for CASA allowances, as set forth in Sections
288 225.460 and 225.560.

289

290 "A reasonable time" shall be determined considering but not
291 limited to the following factors: the nature and size of the project,
292 the extent of design engineering, the amount of off-site
293 preparation, whether equipment can be fabricated or can be
294 purchased, when the project begins (considering both the seasonal
295 nature of the construction activity and the existence of other
296 projects competing for construction labor at the same time, the
297 place of the environmental permit in the sequence of corporate and
298 overall governmental approval), and the nature of the project
299 sponsor (e.g., private, public, regulated).

300
301 "Commence operation", for purposes of Subparts C, D and E, means:

302
303 To have begun any mechanical, chemical, or electronic process, including,
304 for the purpose of a unit, start-up of a unit's combustion chamber, except
305 as provided in 40 CFR 96.105, 96.205, or 96.305, as incorporated by
306 reference in Section 225.140.

307
308 For a unit that undergoes a physical change (other than replacement of the
309 unit by a unit at the same source) after the date the unit commences
310 operation as set forth in the first paragraph of this definition, such date will
311 remain the date of commencement of operation of the unit, which will
312 continue to be treated as the same unit.

313
314 For a unit that is replaced by a unit at the same source (e.g., repowered),
315 after the date the unit commences operation as set forth in the first
316 paragraph of this definition, such date will remain the replaced unit's date
317 of commencement of operation, and the replacement unit will be treated as
318 a separate unit with a separate date for commencement of operation as set
319 forth in this definition as appropriate.

320
321 "Common stack" means a single flue through which emissions from two or more
322 units are exhausted.

323
324 "Compliance account" means:

325
326 For the purposes of Subparts D and E, a CAIR NO_x Allowance Tracking
327 System account, established by USEPA for a CAIR NO_x source or CAIR
328 NO_x Ozone Season source pursuant to 40 CFR 96, subparts FF and FFFF
329 in which any CAIR NO_x allowance or CAIR NO_x Ozone Season
330 allowance allocations for the CAIR NO_x units or CAIR NO_x Ozone
331 Season units at the source are initially recorded and in which are held any
332 CAIR NO_x or CAIR NO_x Ozone Season allowances available for use for a

333 control period in order to meet the source's CAIR NO_x or CAIR NO_x
334 Ozone Season emissions limitations in accordance with Sections 225.410
335 and 225.510, and 40 CFR 96.154 and 96.354, as incorporated by reference
336 in Section 225.140. CAIR NO_x allowances may not be used for
337 compliance with the CAIR NO_x Ozone Season Trading Program and
338 CAIR NO_x Ozone Season allowances may not be used for compliance
339 with the CAIR NO_x Annual Trading Program; or
340

341 For the purposes of Subpart C, a "compliance account" means a CAIR
342 SO₂ compliance account, established by the USEPA for a CAIR SO₂
343 source pursuant to 40 CFR 96, subpart FFF, in which any SO₂ units at the
344 source are initially recorded and in which are held any SO₂ allowances
345 available for use for a control period in order to meet the source's CAIR
346 SO₂ emissions limitations in accordance with Section 225.310 and 40 CFR
347 96.254, as incorporated by reference in Section 225.140.
348

349 "Control period" means:

350
351 For the CAIR SO₂ and NO_x Annual Trading Programs in Subparts C and
352 D, the period beginning January 1 of a calendar year, except as provided
353 in Sections 225.310(d)(3) and 225.410(d)(3), and ending on December 31
354 of the same year, inclusive; or
355

356 For the CAIR NO_x Ozone Season Trading Program in Subpart E, the
357 period beginning May 1 of a calendar year, except as provided in Section
358 225.510(d)(3), and ending on September 30 of the same year, inclusive.
359

360 "Designated representative" means, for the purposes of Subpart B of this Part, ~~the~~
361 ~~natural person as defined in 40 CFR 60.4102, and is the same natural person as~~
362 ~~the person who is the designated representative for the CAIR trading and Acid~~
363 ~~Rain programs.~~
364

365 "Electric generating unit" or "EGU" means a fossil fuel-fired stationary boiler,
366 combustion turbine or combined cycle system that serves a generator that has a
367 nameplate capacity greater than 25 MWe and produces electricity for sale.
368

369 "Flue" means a conduit or duct through which gases or other matter is exhausted
370 to the atmosphere.
371

372 "Fossil fuel" means natural gas, petroleum, coal, or any form of solid, liquid, or
373 gaseous fuel derived from such material.
374

375 "Fossil fuel-fired" means the combusting of any amount of fossil fuel, alone or in

376 combination with any other fuel in any calendar year.

377

378 "Generator" means a device that produces electricity.

379

380 "Gross electrical output" means the total electrical output from an EGU before
 381 making any deductions for energy output used in any way related to the
 382 production of energy. For an EGU generating only electricity, the gross electrical
 383 output is the output from the turbine/generator set.

384

385 "Heat input" means, for the purposes of Subparts C, D, and E, a specified period
 386 of time, the product (in mmBtu/hr) of the gross calorific value of the fuel (in
 387 Btu/lb) divided by 1,000,000 Btu/mmBtu and multiplied by the fuel feed rate into
 388 a combustion device (in lb of fuel/time), as measured, recorded and reported to
 389 USEPA by the CAIR designated representative and determined by USEPA in
 390 accordance with 40 CFR 96, subpart HH, HHH, or HHHH, if applicable, and
 391 excluding the heat derived from preheated combustion air, recirculated flue gases,
 392 or exhaust from other sources.

393

394 "Higher heating value" or "HHV" means the total heat liberated per mass of fuel
 395 burned (Btu/lb), when fuel and dry air at standard conditions undergo complete
 396 combustion and all resultant products are brought to their standard states at
 397 standard conditions.

398

399 "Input mercury" means the mass of mercury that is contained in the coal
 400 combusted within an EGU.

401

402 "Integrated gasification combined cycle" or "IGCC" means a coal-fired electric
 403 utility steam generating unit that burns a synthetic gas derived from coal in a
 404 combined-cycle gas turbine. No coal is directly burned in the unit during
 405 operation.

406

407 "Long-term cold storage" means the complete shutdown of a unit intended to last
 408 for an extended period of time (at least two calendar years) where notice for long-
 409 term cold storage is provided under 40 CFR 75.61(a)(7).

410

411 "Nameplate capacity" means, starting from the initial installation of a generator,
 412 the maximum electrical generating output (in MWe) that the generator is capable
 413 of producing on a steady-state basis and during continuous operation (when not
 414 restricted by seasonal or other deratings) as of such installation as specified by the
 415 manufacturer of the generator or, starting from the completion of any subsequent
 416 physical change in the generator resulting in an increase in the maximum
 417 electrical generating output (in MWe) that the generator is capable of producing
 418 on a steady-state basis and during continuous operation (when not restricted by

419 seasonal or other deratings), such increased maximum amount as of completion as
420 specified by the person conducting the physical change.

421
422 "NIST traceable elemental mercury standards" means either:

- 423
424 1) Compressed gas cylinders having known concentrations of
425 elemental mercury, which have been prepared according to the
426 "EPA Traceability Protocol for Assay and Certification of Gaseous
427 Calibration Standards"; or
- 428
429 2) Calibration gases having known concentrations of elemental
430 mercury, produced by a generator that fully meets the performance
431 requirements of the "EPA Traceability Protocol for Qualification
432 and Certification of Elemental Mercury Gas Generators."

433
434 "NIST traceable source of oxidized mercury" means a generator that is capable of
435 providing known concentrations of vapor phase mercuric chloride (HgCl₂), and
436 that fully meets the performance requirements of the "EPA Traceability Protocol
437 for Qualification and Certification of Oxidized Mercury Gas Generators."

438
439 "Oil-fired unit" means a unit combusting fuel oil for more than 15.0 percent of the
440 annual heat input in a specified year and not qualifying as coal-fired.

441
442 "Output-based emission standard" means, for the purposes of Subpart B of this
443 Part, a maximum allowable rate of emissions of mercury per unit of gross
444 electrical output from an EGU.

445
446 "Potential electrical output capacity" means 33 percent of a unit's maximum design
447 heat input, expressed in mmBtu/hr divided by 3.413 mmBtu/MWh, and multiplied
448 by 8,760 hr/yr.

449
450 "Project sponsor" means a person or an entity, including but not limited to the
451 owner or operator of an EGU or a not-for-profit group, that provides the majority
452 of funding for an energy efficiency and conservation, renewable energy, or clean
453 technology project as listed in Sections 225.460 and 225.560, unless another
454 person or entity is designated by a written agreement as the project sponsor for the
455 purpose of applying for NO_x allowances or NO_x Ozone Season allowances from
456 the CASA.

457
458 "Rated-energy efficiency" means the percentage of thermal energy input that is
459 recovered as useable energy in the form of gross electrical output, useful thermal
460 energy, or both that is used for heating, cooling, industrial processes, or other
461 beneficial uses as follows:

462
 463 For electric generators, rated-energy efficiency is calculated as one
 464 kilowatt hour (3,413 Btu) of electricity divided by the unit's design heat
 465 rate using the higher heating value of the fuel, and expressed as a
 466 percentage.

467
 468 For combined heat and power projects, rated-energy efficiency is
 469 calculated using the following formula:

$$470 \quad \text{REE} = ((\text{GO} + \text{UTE})/\text{HI}) \times 100$$

471
 472 Where:

- 473 REE = Rated-energy efficiency, expressed as percentage.
- GO = Gross electrical output of the system expressed in Btu/hr.
- UTE = Useful thermal output from the system that is used for heating, cooling, industrial processes or other beneficial uses, expressed in Btu/hr.
- HI = Heat input, based upon the higher heating value of fuel, in Btu/hr.

474
 475 "Repowered" means, for the purposes of an EGU, replacement of a coal-fired
 476 boiler with one of the following coal-fired technologies at the same source as the
 477 coal-fired boiler:

- 478 Atmospheric or pressurized fluidized bed combustion;
- 479 Integrated gasification combined cycle;
- 480 Magnetohydrodynamics;
- 481 Direct and indirect coal-fired turbines;
- 482 Integrated gasification fuel cells; or

483
 484 As determined by the USEPA in consultation with the United States
 485 Department of Energy, a derivative of one or more of the technologies
 486 under this definition and any other coal-fired technology capable of
 487 controlling multiple combustion emissions simultaneously with improved
 488 boiler or generation efficiency and with significantly greater waste
 489 reduction relative to the performance of technology in widespread
 490 commercial use as of January 1, 2005.
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 496

497 "Rolling 12-month basis" means, for the purposes of ~~Subpart~~Subparts B and F of
 498 this Part, a determination made on a monthly basis from the relevant data for a
 499 particular calendar month and the preceding 11 calendar months (total of 12
 500 months of data), with two exceptions. For determinations involving one EGU,
 501 calendar months in which the EGU does not operate (zero EGU operating hours)
 502 must not be included in the determination, and must be replaced by a preceding
 503 month or months in which the EGU does operate, so that the determination is still
 504 based on 12 months of data. For determinations involving two or more EGUs,
 505 calendar months in which none of the EGUs covered by the determination
 506 operates (zero EGU operating hours) must not be included in the determination,
 507 and must be replaced by preceding months in which at least one of the EGUs
 508 covered by the determination does operate, so that the determination is still based
 509 on 12 months of data.

511 "Total energy output" means, with respect to a cogeneration unit, the sum of
 512 useful power and useful thermal energy produced by the cogeneration unit.

514 "Useful thermal energy" means, for the purpose of a cogeneration unit, the
 515 thermal energy that is made available to an industrial or commercial process,
 516 excluding any heat contained in condensate return or makeup water:

518 Used in a heating application (e.g., space heating or domestic hot water
 519 heating); or

521 Used in a space cooling application (e.g., thermal energy used by an
 522 absorption chiller).

524 (Source: Amended at 33 Ill. Reg. _____, effective _____)

526 **Section 225.140 Incorporations by Reference**

527 The following materials are incorporated by reference. These incorporations do not include any
 528 later amendments or editions.

- 531 a) Appendix A, Subpart A, and Performance Specifications 2 and 3 of Appendix B
 532 of 40 CFR 60, 60.17, 60.45a, 60.49a(k)(1) and (p), 60.50a(h), and 60.4170
 533 through 60.4176 (2005).
- 534 b) 40 CFR 72.2 (2005).
- 535 c) 40 CFR 75.4, 75.11 through 75.14, 75.16 through 75.19, 75.30, 75.34 through
 536 75.37, 75.40 through 75.48, 75.53(e), 75.57(c)(2)(i) through 75.57(c)(2)(vi),
 537 75.60 through 75.67, 75.71, 75.74(c), Sections 2.1.1.5, 2.1.1.2, 7.7, and 7.8 of
 538 the Appendix to Part 75 of Title 40, Code of Federal Regulations (2005).

Appendix A to 40 CFR 75, Appendix C to 40 CFR 75, Section 3.3.5 of Appendix F to 40 CFR 75 (2006)~~40 CFR 75 (2006)~~.

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- de) 40 CFR 78 (2006).
- ed) 40 CFR 96, CAIR SO₂ Trading Program, subparts AAA (excluding 40 CFR 96.204 and 96.206), BBB, FFF, GGG, and HHH (2006).
- fe) 40 CFR 96, CAIR NO_x Annual Trading Program, subparts AA (excluding 40 CFR 96.104, 96.105(b)(2), and 96.106), BB, FF, GG, and HH (2006).
- gf) 40 CFR 96, CAIR NO_x Ozone Season Trading Program, subparts AAAA (excluding 40 CFR 96.304, 96.305(b)(2), and 96.306), BBBB, FFFF, GGGG, and HHHH (2006).
- hg) ASTM. The following methods from the American Society for Testing and Materials, 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken PA 19428-2959, (610) 832-9585:
 - 1) ASTM D388-77 (approved February 25, 1977), D388-90 (approved March 30, 1990), D388-91a (approved April 15, 1991), D388-95 (approved January 15, 1995), D388-98a (approved September 10, 1998), or D388-99 (approved September 10, 1999, reapproved in 2004), Classification of Coals by Rank.
 - 2) ASTM D3173-03, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke (Approved April 10, 2003).
 - 3) ASTM D3684-01, Standard Test Method for Total Mercury in Coal by the Oxygen Bomb Combustion/Atomic Absorption Method (Approved October 10, 2001).
 - 4) ASTM D4840-99, Standard Guide for Sampling Chain-of-Custody Procedures (Reapproved 2004).
 - 54) ASTM D5865-04, Standard Test Method for Gross Calorific Value of Coal and Coke (Approved April 1, 2004).
 - 65) ASTM D6414-01, Standard Test Method for Total Mercury in Coal and Coal Combustion Residues by Acid Extraction or Wet Oxidation/Cold Vapor Atomic Absorption (Approved October 10, 2001).

- 582 7) ASTM D6784-02, Standard Test Method for Elemental, Oxidized,
583 Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired
584 Stationary Sources (Ontario Hydro Method) (Approved April 10, 2002).
585
586 8) ASTM D6911-03, Standard Guide for Packaging and Shipping
587 Environmental Samples for Laboratory Analysis.
588
589 9) ASTM D7036-04, Standard Practice for Competence of Air Emission
590 Testing Bodies.
591
592 ih) Federal Energy Management Program, M&V Guidelines: Measurement and
593 Verification for Federal Energy Projects, US Department of Energy, Office of
594 Energy Efficiency and Renewable Energy, Version 2.2, DOE/GO-102000-0960
595 (September 2000).

596
597 (Source: Amended at 33 Ill. Reg. _____, effective _____)
598

599 SUBPART B: CONTROL OF MERCURY EMISSIONS
600 FROM COAL-FIRED ELECTRIC GENERATING UNITS

601
602 **Section 225.202 Measurement Methods**

603
604 Measurement of mercury must be according to the following:

- 605
606 a) Continuous emission monitoring pursuant to Appendix B to this Part or an
607 alternative emissions monitoring system, alternative reference method for
608 measuring emissions, or other alternative to the emissions monitoring and
609 measurement requirements of Sections 225.240 through 225.290, if such
610 alternative is submitted to the Agency in writing and approved in writing by the
611 Manager of the Bureau of Air's Compliance Section, 40 CFR 75 (2005).
612
613 b) ASTM D3173-03, Standard Test Method for Moisture in the Analysis Sample of
614 Coal and Coke (Approved April 10, 2003), incorporated by reference in Section
615 225.140.
616
617 c) ASTM D3684-01, Standard Test Method for Total Mercury in Coal by the
618 Oxygen Bomb Combustion/Atomic Absorption Method (Approved October 10,
619 2001), incorporated by reference in Section 225.140.
620
621 d) ASTM D5865-04, Standard Test Method for Gross Calorific Value of Coal and
622 Coke (Approved April 1, 2004), incorporated by reference in Section 225.140.
623

- 624 e) ASTM D6414-01, Standard Test Method for Total Mercury in Coal and Coal
 625 Combustion Residues by Acid Extraction or Wet Oxidation/Cold Vapor Atomic
 626 Absorption (Approved October 10, 2001), incorporated by reference in Section
 627 225.140.
 628
 629 f) ASTM D6784-02, Standard Test Method for Elemental, Oxidized, Particle-Bound
 630 and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources
 631 (Ontario Hydro Method) (Approved April 10, 2002), incorporated by reference in
 632 Section 225.140.
 633
 634 g) Emissions testing pursuant to Appendix A of 40 CFR 60.
 635
 636 (Source: Amended at 33 Ill. Reg. _____, effective _____)
 637

638 **Section 225.210 Compliance Requirements**
 639

- 640 a) Permit Requirements.
 641 The owner or operator of each source with one or more EGUs subject to this
 642 Subpart B at the source must apply for a CAAPP permit that addresses the
 643 applicable requirements of this Subpart B.
 644
 645 b) Monitoring and Testing Requirements.
 646
 647 1) The owner or operator of each source and each EGU at the source must
 648 comply with either the monitoring requirements of Sections 225.240
 649 through 225.290 of this Subpart B, the periodic emissions testing
 650 requirements of Section 225.239 of this Subpart B, or an alternative
 651 emissions monitoring system, alternative reference method for measuring
 652 emissions, or other alternative to the emissions monitoring and
 653 measurement requirements of Sections 225.240 through 225.290, if such
 654 alternative is submitted to the Agency in writing and approved in writing
 655 by the Manager of the Bureau of Air's Compliance Section.
 656
 657 2) The compliance of each EGU with the mercury requirements of Sections
 658 225.230 and 225.237 of this Subpart B must be determined by the
 659 emissions measurements recorded and reported in accordance with either
 660 Sections 225.240 through 225.290 of this Subpart B, Section 225.239 of
 661 this Subpart B, or an alternative emissions monitoring system, alternative
 662 reference method for measuring emissions, or other alternative to the
 663 emissions monitoring and measurement requirements of Sections 225.240
 664 through 225.290, if such alternative is submitted to the Agency in writing
 665 and approved in writing by the Manager of the Bureau of Air's
 666 Compliance Section.

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- c) Mercury Emission Reduction Requirements
The owner or operator of any EGU subject to this Subpart B must comply with applicable requirements for control of mercury emissions of Section 225.230 or Section 225.237 of this Subpart B.

 - d) Recordkeeping and Reporting Requirements
Unless otherwise provided, the owner or operator of a source with one or more EGUs at the source must keep on site at the source each of the documents listed in subsections (d)(1) through (d)(3) of this Section for a period of five years from the date the document is created. This period may be extended, in writing by the Agency, for cause, at any time prior to the end of five years.
 - 1) All emissions monitoring information gathered in accordance with Sections 225.240 through 225.290 and all periodic emissions testing information gathered in accordance with Section 225.239.
 - 2) Copies of all reports, compliance certifications, and other submissions and all records made or required or documents necessary to demonstrate compliance with the requirements of this Subpart B.
 - 3) Copies of all documents used to complete a permit application and any other submission under this Subpart B.

 - e) Liability.
 - 1) The owner or operator of each source with one or more EGUs must meet the requirements of this Subpart B.
 - 2) Any provision of this Subpart B that applies to a source must also apply to the owner and operator of such source and to the owner or operator of each EGU at the source.
 - 3) Any provision of this Subpart B that applies to an EGU must also apply to the owner or operator of such EGU.

 - f) Effect on Other Authorities. No provision of this Subpart B may be construed as exempting or excluding the owner or operator of a source or EGU from compliance with any other provision of an approved State Implementation Plan, a permit, the Act, or the CAA.

708 (Source: Amended at 33 Ill. Reg. _____, effective _____)
709

Section 225.220 Clean Air Act Permit Program (CAAPP) Permit Requirements

a) Application Requirements.

- 1) Each source with one or more EGUs subject to the requirements of this Subpart B is required to submit a CAAPP permit application that addresses all applicable requirements of this Subpart B, applicable to each EGU at the source.
- 2) For any EGU that commenced commercial operation:
 - A) on or before December 31, 2008, the owner or operator of such EGUs must submit an initial permit application or application for CAAPP permit modification that meets the requirements of this Section on or before December 31, 2008.
 - B) after December 31, 2008, the owner or operator of any such EGU must submit an initial CAAPP permit application or application for CAAPP modification that meets the requirements of this Section not later than 180 days before initial startup of the EGU, unless the construction permit issued for the EGU addresses the requirements of this Subpart B.

b) Contents of Permit Applications.

In addition to other information required for a complete application for CAAPP permit or CAAPP permit modification, the application must include the following information:

- 1) The ORIS (Office of Regulatory Information Systems) or facility code assigned to the source by the U.S. Department of Energy, Energy Information Administration, if applicable.
- 2) Identification of each EGU at the source.
- 3) The intended approach to the monitoring requirements of Sections 225.240 through 225.290 of this Subpart B, or, in the alternative, the applicant may include its intended approach to the testing requirement of Section 225.239 of this Subpart B.
- 4) The intended approach to the mercury emission reduction requirements of Section 225.230 or 225.237 of this Subpart B, as applicable.

c) Permit Contents.

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- 1) Each CAAPP permit issued by the Agency for a source with one or more EGUs subject to the requirements of this Subpart B must contain federally enforceable conditions addressing all applicable requirements of this Subpart B, which conditions must be a complete and segregable portion of the source's entire CAAPP permit.
 - 2) In addition to conditions related to the applicable requirements of this Subpart B, each such CAAPP permit must also contain the information specified under subsection (b) of this Section.

(Source: Amended at 33 Ill. Reg. _____, effective _____)

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766 **Section 225.230 Emission Standards for EGUs at Existing Sources**
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768 a) Emission Standards.
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- 1) Except as provided in Sections 225.230(b) and (d), 225.232 through 225.234, 225.239, and 225.291 through 225.299 of this Subpart B, ~~beginning~~Beginning July 1, 2009, the owner or operator of a source with one or more EGUs subject to this Subpart B that commenced commercial operation on or before December 31, 2008, must comply with one of the following standards for each EGU on a rolling 12-month basis:
 - A) An emission standard of 0.0080 lb mercury/GWh gross electrical output; or
 - B) A minimum 90-percent reduction of input mercury.
 - 2) For an EGU complying with subsection (a)(1)(A) of this Section, the actual mercury emission rate of the EGU for each 12-month rolling period, as monitored in accordance with this Subpart B and calculated as follows, must not exceed the applicable emission standard:

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$$ER = \sum_{i=1}^{12} E_i \div \sum_{i=1}^{12} O_i$$

789 Where:

- 790
- ER = Actual mercury emissions rate of the EGU for the particular 12-month rolling period, expressed in lb/GWh.
 - E_i = Actual mercury emissions of the EGU, in lbs, in an individual month in the 12-month rolling period, as determined in

accordance with the emissions monitoring provisions of this Subpart B.

O_i = Gross electrical output of the EGU, in GWh, in an individual month in the 12-month rolling period, as determined in accordance with Section 225.263 of this Subpart B.

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- 3) For an EGU complying with subsection (a)(1)(B) of this Section, the actual control efficiency for mercury emissions achieved by the EGU for each 12-month rolling period, as monitored in accordance with this Subpart B and calculated as follows, must meet or exceed the applicable efficiency requirement:

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$$CE = 100 \times \left\{ 1 - \left(\frac{\sum_{i=1}^{12} E_i}{\sum_{i=1}^{12} I_i} \right) \right\}$$

Where:

- CE = Actual control efficiency for mercury emissions of the EGU for the particular 12-month rolling period, expressed as a percent.
 E_i = Actual mercury emissions of the EGU, in lbs, in an individual month in the 12-month rolling period, as determined in accordance with the emissions monitoring provisions of this Subpart B.
 I_i = Amount of mercury in the fuel fired in the EGU, in lbs, in an individual month in the 12-month rolling period, as determined in accordance with Section 225.265 of this Subpart B.

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- b) Alternative Emission Standards for Single EGUs.
- 1) As an alternative to compliance with the emission standards in subsection (a) of this Section, the owner or operator of the EGU may comply with the emission standards of this Subpart B by demonstrating that the actual emissions of mercury from the EGU are less than the allowable emissions of mercury from the EGU on a rolling 12-month basis.
- 2) For the purpose of demonstrating compliance with the alternative emission standards of this subsection (b), for each rolling 12-month period, the actual emissions of mercury from the EGU, as monitored in accordance with this Subpart B, must not exceed the allowable emissions of mercury from the EGU, as further provided by the following formulas:

$$E_{12} \leq A_{12}$$

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$$E_{12} = \sum_{i=1}^{12} E_i$$

$$A_{12} = \sum_{i=1}^{12} A_i$$

Where:

- E_{12} = Actual mercury emissions of the EGU for the particular 12-month rolling period.
- A_{12} = Allowable mercury emissions of the EGU for the particular 12-month rolling period.
- E_i = Actual mercury emissions of the EGU in an individual month in the 12-month rolling period.
- A_i = Allowable mercury emissions of the EGU in an individual month in the 12-month rolling period, based on either the input mercury to the unit ($A_{Input\ i}$) or the electrical output from the EGU ($A_{Output\ i}$), as selected by the owner or operator of the EGU for that given month.
- $A_{Input\ i}$ = Allowable mercury emissions of the EGU in an individual month based on the input mercury to the EGU, calculated as 10.0 percent (or 0.100) of the input mercury to the EGU.
- $A_{Output\ i}$ = Allowable mercury emissions of the EGU in a particular month based on the electrical output from the EGU, calculated as the product of the output based mercury limit, i.e., 0.0080 lb/GWh, and the electrical output from the EGU, in GWh.

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- 3) If the owner or operator of an EGU does not conduct the necessary sampling, analysis, and recordkeeping, in accordance with Section 225.265 of this Subpart B, to determine the mercury input to the EGU, the allowable emissions of the EGU must be calculated based on the electrical output of the EGU.
- c) If two or more EGUs are served by common stack(s) and the owner or operator conducts monitoring for mercury emissions in the common stack(s), as provided for by Sections 1.14 through 1.18 of Appendix B to this Part 40 CFR 75, subpart I, such that the mercury emissions of each EGU are not determined separately, compliance of the EGUs with the applicable emission standards of this Subpart B must be determined as if the EGUs were a single EGU.
- d) Alternative Emission Standards for Multiple EGUs.

841 1) As an alternative to compliance with the emission standards of subsection
 842 (a) of this Section, the owner or operator of a source with multiple EGUs
 843 may comply with the emission standards of this Subpart B by
 844 demonstrating that the actual emissions of mercury from all EGUs at the
 845 source are less than the allowable emissions of mercury from all EGUs at
 846 the source on a rolling 12-month basis.

847
 848 2) For the purposes of the alternative emission standard of subsection (d)(1)
 849 of this Section, for each rolling 12-month period, the actual emissions of
 850 mercury from all the EGUs at the source, as monitored in accordance with
 851 this Subpart B, must not exceed the sum of the allowable emissions of
 852 mercury from all the EGUs at the source, as further provided by the
 853 following formulas:

$$E_S \leq A_S$$

$$E_S = \sum_{i=1}^n E_i$$

$$A_S = \sum_{i=1}^n A_i$$

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 861 Where:
 862

E_S = Sum of the actual mercury emissions of the EGUs at the source.

A_S = Sum of the allowable mercury emissions of the EGUs at the source.

E_i = Actual mercury emissions of an individual EGU at the source, as
 determined in accordance with subsection (b)(2) of this Section.

A_i = Allowable mercury emissions of an individual EGU at the source, as
 determined in accordance with subsection (b)(2) of this Section.

n = Number of EGUs covered by the demonstration.

863
 864 3) If an owner or operator of a source with two or more EGUs that is relying
 865 on this subsection (d) to demonstrate compliance fails to meet the
 866 requirements of this subsection (d) in a given 12-month rolling period, all
 867 EGUs at such source covered by the compliance demonstration are
 868 considered out of compliance with the applicable emission standards of
 869 this Subpart B for the entire last month of that period.

870
 871 (Source: Amended at 33 Ill. Reg. _____, effective _____)
 872

873 **Section 225.233 Multi-Pollutant Standards (MPS)**

- 874
 875 a) General.
 876
 877 1) As an alternative to compliance with the emissions standards of Section
 878 225.230(a), the owner of eligible EGUs may elect for those EGUs to
 879 demonstrate compliance pursuant to this Section, which establishes
 880 control requirements and standards for emissions of NO_x and SO₂, as well
 881 as for emissions of mercury.
 882
 883 2) For the purpose of this Section, the following requirements apply:
 884
 885 A) An eligible EGU is an EGU that is located in Illinois and which
 886 commenced commercial operation on or before December 31,
 887 2004; and
 888
 889 B) Ownership of an eligible EGU is determined based on direct
 890 ownership, by the holding of a majority interest in a company that
 891 owns the EGU or EGUs, or by the common ownership of the
 892 company that owns the EGU, whether through a parent-subsiary
 893 relationship, as a sister corporation, or as an affiliated corporation
 894 with the same parent corporation, provided that the owner has the
 895 right or authority to submit a CAAPP application on behalf of the
 896 EGU.
 897
 898 3) The owner of one or more EGUs electing to demonstrate compliance with
 899 this Subpart B pursuant to this Section must submit an application for a
 900 CAAPP permit modification to the Agency, as provided in Section
 901 225.220, that includes the information specified in subsection (b) of this
 902 Section and which clearly states the owner's election to demonstrate
 903 compliance pursuant to this Section 225.233.
 904
 905 A) If the owner of one or more EGUs elects to demonstrate
 906 compliance with this Subpart pursuant to this Section, then all
 907 EGUs it owns in Illinois as of July 1, 2006, as defined in
 908 subsection (a)(2)(B) of this Section, must be thereafter subject to
 909 the standards and control requirements of this Section, except as
 910 provided in subsection (a)(3)(B). Such EGUs must be referred to
 911 as a Multi-Pollutant Standard (MPS) Group.
 912
 913 B) Notwithstanding the foregoing, the owner may exclude from an
 914 MPS Group any EGU scheduled for permanent shutdown that the
 915 owner so designates in its CAAPP application required to be
 916 submitted pursuant to subsection (a)(3) of this Section, with

917 compliance for such units to be achieved by means of Section
918 225.235.

919
920 4) When an EGU is subject to the requirements of this Section, the
921 requirements apply to all owners or operators of the EGU, and to the
922 designated representative for the EGU.

923

924 b) Notice of Intent.

925 The owner of one or more EGUs that intends to comply with this Subpart B by
926 means of this Section must notify the Agency of its intention by December 31,
927 2007. The following information must accompany the notification:

928

929 1) The identification of each EGU that will be complying with this Subpart B
930 by means of the multi-pollutant standards contained in this Section, with
931 evidence that the owner has identified all EGUs that it owned in Illinois as
932 of July 1, 2006 and which commenced commercial operation on or before
933 December 31, 2004;

934

935 2) If an EGU identified in subsection (b)(1) of this Section is also owned or
936 operated by a person different than the owner submitting the notice of
937 intent, a demonstration that the submitter has the right to commit the EGU
938 or authorization from the responsible official for the EGU accepting the
939 application;

940

941 3) The Base Emission Rates for the EGUs, with copies of supporting data
942 and calculations;

943

944 4) A summary of the current control devices installed and operating on each
945 EGU and identification of the additional control devices that will likely be
946 needed for the each EGU to comply with emission control requirements of
947 this Section, including identification of each EGU in the MPS group that
948 will be addressed by subsection (c)(1)(B) of this Section, with information
949 showing that the eligibility criteria for this subsection (b) are satisfied; and

950

951 5) Identification of each EGU that is scheduled for permanent shut down, as
952 provided by Section 225.235, which will not be part of the MPS Group
953 and which will not be demonstrating compliance with this Subpart B
954 pursuant to this Section.

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956 c) Control Technology Requirements for Emissions of Mercury.

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958 1) Requirements for EGUs in an MPS Group.

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- A) For each EGU in an MPS Group other than an EGU that is addressed by subsection (c)(1)(B) of this Section for the period beginning July 1, 2009 (or December 31, 2009 for an EGU for which an SO₂ scrubber or fabric filter is being installed to be in operation by December 31, 2009), and ending on December 31, 2014 (or such earlier date that the EGU is subject to the mercury emission standard in subsection (d)(1) of this Section), the owner or operator of the EGU must install, to the extent not already installed, and properly operate and maintain one of the following emission control devices:
- i) A Halogenated Activated Carbon Injection System, complying with the sorbent injection requirements of subsection (c)(2) of this Section, except as may be otherwise provided by subsection (c)(4) of this Section, and followed by a Cold-Side Electrostatic Precipitator or Fabric Filter; or
 - ii) If the boiler fires bituminous coal, a Selective Catalytic Reduction (SCR) System and an SO₂ Scrubber.
- B) An owner of an EGU in an MPS Group has two options under this subsection (c). For an MPS Group that contains EGUs smaller than 90 gross MW in capacity, the owner may designate any such EGUs to be not subject to subsection (c)(1)(A) of this Section. Or, for an MPS Group that contains EGUs with gross MW capacity of less than 115 MW, the owner may designate any such EGUs to be not subject to subsection (c)(1)(A) of this Section, provided that the aggregate gross MW capacity of the designated EGUs does not exceed 4% of the total gross MW capacity of the MPS Group. For any EGU subject to one of these two options, unless the EGU is subject to the emission standards in subsection (d)(2) of this Section, beginning on January 1, 2013, and continuing until such date that the owner or operator of the EGU commits to comply with the mercury emission standard in subsection (d)(2) of this Section, the owner or operator of the EGU must install and properly operate and maintain a Halogenated Activated Carbon Injection System that complies with the sorbent injection requirements of subsection (c)(2) of this Section, except as may be otherwise provided by subsection (c)(4) of this Section, and followed by either a Cold-Side Electrostatic Precipitator or Fabric Filter. The use of a properly installed, operated, and maintained Halogenated Activated Carbon Injection System that meets the

- 1003 sorbent injection requirements of subsection (c)(2) of this Section
 1004 is defined as the "principal control technique."
 1005
- 1006 2) For each EGU for which injection of halogenated activated carbon is
 1007 required by subsection (c)(1) of this Section, the owner or operator of the
 1008 EGU must inject halogenated activated carbon in an optimum manner,
 1009 which, except as provided in subsection (c)(4) of this Section, is defined as
 1010 all of the following:
 1011
- 1012 A) The use of an injection system designed for effective absorption of
 1013 mercury, considering the configuration of the EGU and its
 1014 ductwork;
 1015
- 1016 B) The injection of halogenated activated carbon manufactured by
 1017 Alstom, Norit, or Sorbent Technologies, or Calgon Carbon's
 1018 FLUEPAC MC Plus, or the injection of any other halogenated
 1019 activated carbon or sorbent that the owner or operator of the EGU
 1020 has demonstrated to have similar or better effectiveness for control
 1021 of mercury emissions; and
 1022
- 1023 C) The injection of sorbent at the following minimum rates, as
 1024 applicable:
 1025
- 1026 i) For an EGU firing subbituminous coal, 5.0 lbs per million
 1027 actual cubic feet or, for any cyclone-fired EGU that will
 1028 install a scrubber and baghouse by December 31, 2012, and
 1029 which already meets an emission rate of 0.020 lbs
 1030 mercury/GWh gross electrical output or at least 75 percent
 1031 reduction of input mercury, 2.5 lbs per million actual cubic
 1032 feet;
 1033
- 1034 ii) For an EGU firing bituminous coal, 10.0 lbs per million
 1035 actual cubic feet for any cyclone-fired EGU that will install
 1036 a scrubber and baghouse by December 31, 2012, and which
 1037 already meets an emission rate of 0.020 lb mercury/GWh
 1038 gross electrical output or at least 75 percent reduction of
 1039 input mercury, 5.0 lbs per million actual cubic feet;
 1040
- 1041 iii) For an EGU firing a blend of subbituminous and
 1042 bituminous coal, a rate that is the weighted average of the
 1043 above rates, based on the blend of coal being fired; or
 1044

1045 iv) A rate or rates set lower by the Agency, in writing, than the
 1046 rate specified in any of subsections (c)(2)(C)(i),
 1047 (c)(2)(C)(ii), or (c)(2)(C)(iii) of this Section on a unit-
 1048 specific basis, provided that the owner or operator of the
 1049 EGU has demonstrated that such rate or rates are needed so
 1050 that carbon injection will not increase particulate matter
 1051 emissions or opacity so as to threaten noncompliance with
 1052 applicable requirements for particulate matter or opacity.
 1053

1054 D) For the purposes of subsection (c)(2)(C) of this Section, the flue
 1055 gas flow rate must be determined for the point of sorbent injection;
 1056 provided that this flow rate may be assumed to be identical to the
 1057 stack flow rate if the gas temperatures at the point of injection and
 1058 the stack are normally within 100°F, or the flue gas flow rate may
 1059 otherwise be calculated from the stack flow rate, corrected for the
 1060 difference in gas temperatures.
 1061

1062 3) The owner or operator of an EGU that seeks to operate an EGU with an
 1063 activated carbon injection rate or rates that are set on a unit-specific basis
 1064 pursuant to subsection (c)(2)(C)(iv) of this Section must submit an
 1065 application to the Agency proposing such rate or rates, and must meet the
 1066 requirements of subsections (c)(3)(A) and (c)(3)(B) of this Section, subject
 1067 to the limitations of subsections (c)(3)(C) and (c)(3)(D) of this Section:
 1068

1069 A) The application must be submitted as an application for a new or
 1070 revised federally enforceable operating permit for the EGU, and it
 1071 must include a summary of relevant mercury emission data for the
 1072 EGU, the unit-specific injection rate or rates that are proposed, and
 1073 detailed information to support the proposed injection rate or rates;
 1074 and
 1075

1076 B) This application must be submitted no later than the date that
 1077 activated carbon must first be injected. For example, the owner or
 1078 operator of an EGU that must inject activated carbon pursuant to
 1079 subsection (c)(1)(A) of this subsection must apply for unit-specific
 1080 injection rate or rates by July 1, 2009. Thereafter, the owner or
 1081 operator of the EGU may supplement its application; and
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1083 C) Any decision of the Agency denying a permit or granting a permit
 1084 with conditions that set a lower injection rate or rates may be
 1085 appealed to the Board pursuant to Section 39 of the Act; and
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- D) The owner or operator of an EGU may operate at the injection rate or rates proposed in its application until a final decision is made on the application, including a final decision on any appeal to the Board.
 - 4) During any evaluation of the effectiveness of a listed sorbent, an alternative sorbent, or other technique to control mercury emissions, the owner or operator of an EGU need not comply with the requirements of subsection (c)(2) of this Section for any system needed to carry out the evaluation, as further provided as follows:
 - A) The owner or operator of the EGU must conduct the evaluation in accordance with a formal evaluation program submitted to the Agency at least 30 days prior to commencement of the evaluation;
 - B) The duration and scope of the evaluation may not exceed the duration and scope reasonably needed to complete the desired evaluation of the alternative control technique, as initially addressed by the owner or operator in a support document submitted with the evaluation program;
 - C) The owner or operator of the EGU must submit a report to the Agency no later than 30 days after the conclusion of the evaluation that describes the evaluation conducted and which provides the results of the evaluation; and
 - D) If the evaluation of the alternative control technique shows less effective control of mercury emissions from the EGU than was achieved with the principal control technique, the owner or operator of the EGU must resume use of the principal control technique. If the evaluation of the alternative control technique shows comparable effectiveness to the principal control technique, the owner or operator of the EGU may either continue to use the alternative control technique in a manner that is at least as effective as the principal control technique, or it may resume use of the principal control technique. If the evaluation of the alternative control technique shows more effective control of mercury emissions than the control technique, the owner or operator of the EGU must continue to use the alternative control technique in a manner that is more effective than the principal control technique, so long as it continues to be subject to this subsection (c).

- 1129 5) In addition to complying with the applicable recordkeeping and
 1130 monitoring requirements in Sections 225.240 through 225.290, the owner
 1131 or operator of an EGU that elects to comply with this Subpart B by means
 1132 of this Section must also comply with the following additional
 1133 requirements:
 1134
- 1135 A) For the first 36 months that injection of sorbent is required, it must
 1136 maintain records of the usage of sorbent, the exhaust gas flow rate
 1137 from the EGU, and the sorbent feed rate, in pounds per million
 1138 actual cubic feet of exhaust gas at the injection point, on a weekly
 1139 average;
 1140
- 1141 B) After the first 36 months that injection of sorbent is required, it
 1142 must monitor activated sorbent feed rate to the EGU, flue gas
 1143 temperature at the point of sorbent injection, and exhaust gas flow
 1144 rate from the EGU, automatically recording this data and the
 1145 sorbent carbon feed rate, in pounds per million actual cubic feet of
 1146 exhaust gas at the injection point, on an hourly average; and
 1147
- 1148 C) If a blend of bituminous and subbituminous coal is fired in the
 1149 EGU, it must keep records of the amount of each type of coal
 1150 burned and the required injection rate for injection of activated
 1151 carbon, on a weekly basis.
 1152
- 1153 6) As an alternative to the CEMS monitoring, recordkeeping, and reporting
 1154 requirements in Sections 225.240 through 225.290, the owner or operator
 1155 of an EGU may elect to comply with the emissions testing, monitoring,
 1156 recordkeeping, and reporting requirements in Section 225.239(c), (d), (e),
 1157 (f)(1) and (2), (h)(2), (i)(3) and (4), and (j)(1).
 1158
- 1159 ~~7~~6) In addition to complying with the applicable reporting requirements in
 1160 Sections 225.240 through 225.290, the owner or operator of an EGU that
 1161 elects to comply with this Subpart B by means of this Section must also
 1162 submit quarterly reports for the recordkeeping and monitoring conducted
 1163 pursuant to subsection (c)(5) of this Section.
 1164
- 1165 d) Emission Standards for Mercury.
 1166
- 1167 1) For each EGU in an MPS Group that is not addressed by subsection
 1168 (c)(1)(B) of this Section, beginning January 1, 2015 (or such earlier date
 1169 when the owner or operator of the EGU notifies the Agency that it will
 1170 comply with these standards) and continuing thereafter, the owner or

- 1171 operator of the EGU must comply with one of the following standards on
 1172 a rolling 12-month basis:
 1173
 1174 A) An emission standard of 0.0080 lb mercury/GWh gross electrical
 1175 output; or
 1176
 1177 B) A minimum 90-percent reduction of input mercury.
 1178
 1179 2) For each EGU in an MPS Group that has been addressed under subsection
 1180 (c)(1)(B) of this Section, beginning on the date when the owner or
 1181 operator of the EGU notifies the Agency that it will comply with these
 1182 standards and continuing thereafter, the owner or operator of the EGU
 1183 must comply with one of the following standards on a rolling 12-month
 1184 basis:
 1185
 1186 A) An emission standard of 0.0080 lb mercury/GWh gross electrical
 1187 output; or
 1188
 1189 B) A minimum 90-percent reduction of input mercury.
 1190
 1191 3) Compliance with the mercury emission standard or reduction requirement
 1192 of this subsection (d) must be calculated in accordance with Section
 1193 225.230(a) or (d).
 1194
 1195 4) Until June 30, 2012, as an alternative to demonstrating compliance with
 1196 the emissions standards in this subsection (d), the owner or operator of an
 1197 EGU may elect to comply with the emissions testing requirements in
 1198 Section 225.239(c), (d), (e), (f)(1) and (2), (h)(2), (i)(3) and (4), and (j)(1)
 1199 of this Subpart.
 1200
 1201 e) Emission Standards for NO_x and SO₂.
 1202
 1203 1) NO_x Emission Standards.
 1204
 1205 A) Beginning in calendar year 2012 and continuing in each calendar
 1206 thereafter, for the EGUs in each MPS Group, the owner and
 1207 operator of the EGUs must comply with an overall NO_x annual
 1208 emission rate of no more than 0.11 lb/million Btu or an emission
 1209 rate equivalent to 52 percent of the Base Annual Rate of NO_x
 1210 emissions, whichever is more stringent.
 1211
 1212 B) Beginning in the 2012 ozone season and continuing in each ozone
 1213 season thereafter, for the EGUs in each MPS Group, the owner and

operator of the EGUs must comply with an overall NO_x seasonal emission rate of no more than 0.11 lb/million Btu or an emission rate equivalent to 80 percent of the Base Seasonal Rate of NO_x emissions, whichever is more stringent.

2) SO₂ Emission Standards.

A) Beginning in calendar year 2013 and continuing in calendar year 2014, for the EGUs in each MPS Group, the owner and operator of the EGUs must comply with an overall SO₂ annual emission rate of 0.33 lb/million Btu or a rate equivalent to 44 percent of the Base Rate of SO₂ emissions, whichever is more stringent.

B) Beginning in calendar year 2015 and continuing in each calendar year thereafter, for the EGUs in each MPS Grouping, the owner and operator of the EGUs must comply with an overall annual emission rate for SO₂ of 0.25 lbs/million Btu or a rate equivalent to 35 percent of the Base Rate of SO₂ emissions, whichever is more stringent.

3) Compliance with the NO_x and SO₂ emission standards must be demonstrated in accordance with Sections 225.310, 225.410, and 225.510. The owner or operator of EGUs must complete the demonstration of compliance before March 1 of the following year for annual standards and before November 1 for seasonal standards, by which date a compliance report must be submitted to the Agency.

f) Requirements for NO_x and SO₂ Allowances.

1) The owner or operator of EGUs in an MPS Group must not sell or trade to any person or otherwise exchange with or give to any person NO_x allowances allocated to the EGUs in the MPS Group for vintage years 2012 and beyond that would otherwise be available for sale, trade, or exchange as a result of actions taken to comply with the standards in subsection (e) of this Section. Such allowances that are not retired for compliance must be surrendered to the Agency on an annual basis, beginning in calendar year 2013. This provision does not apply to the use, sale, exchange, gift, or trade of allowances among the EGUs in an MPS Group.

2) The owners or operators of EGUs in an MPS Group must not sell or trade to any person or otherwise exchange with or give to any person SO₂ allowances allocated to the EGUs in the MPS Group for vintage years

1257 2013 and beyond that would otherwise be available for sale or trade as a
 1258 result of actions taken to comply with the standards in subsection (e) of
 1259 this Section. Such allowances that are not retired for compliance, or
 1260 otherwise surrendered pursuant to a consent decree to which the State of
 1261 Illinois is a party, must be surrendered to the Agency on an annual basis,
 1262 beginning in calendar year 2014. This provision does not apply to the use,
 1263 sale, exchange, gift, or trade of allowances among the EGUs in an MPS
 1264 Group.
 1265

1266 3) The provisions of this subsection (f) do not restrict or inhibit the sale or
 1267 trading of allowances that become available from one or more EGUs in a
 1268 MPS Group as a result of holding allowances that represent over-
 1269 compliance with the NO_x or SO₂ standard in subsection (e) of this Section,
 1270 once such a standard becomes effective, whether such over-compliance
 1271 results from control equipment, fuel changes, changes in the method of
 1272 operation, unit shut downs, or other reasons.
 1273

1274 4) For purposes of this subsection (f), NO_x and SO₂ allowances mean
 1275 allowances necessary for compliance with Subpart W of Section 217 (NO_x
 1276 Trading Program for Electrical Generating Units)Sections 225.310,
 1277 225.410, or 225.510, 40 CFR 72, Subparts or subparts A through IA and
 1278 AAAA of 40 CFR 96, or any future federal NO_x or SO₂ emissions trading
 1279 programs that include Illinois sources. This Section does not prohibit the
 1280 owner or operator of EGUs in an MPS Group from purchasing or
 1281 otherwise obtaining allowances from other sources as allowed by law for
 1282 purposes of complying with federal or state requirements, except as
 1283 specifically set forth in this Section.
 1284

1285 5) Before March 1, 2010, and continuing each year thereafter, the owner or
 1286 operator of EGUs in an MPS Group must submit a report to the Agency
 1287 that demonstrates compliance with the requirements of this subsection (f)
 1288 for the previous calendar year, and which includes identification of any
 1289 allowances that have been surrendered to the USEPA or to the Agency and
 1290 any allowances that were sold, gifted, used, exchanged, or traded because
 1291 they became available due to over-compliance. All allowances that are
 1292 required to be surrendered must be surrendered by August 31, unless
 1293 USEPA has not yet deducted the allowances from the previous year. A
 1294 final report must be submitted to the Agency by August 31 of each year,
 1295 verifying that the actions described in the initial report have taken place
 1296 or, if such actions have not taken place, an explanation of all changes that
 1297 have occurred and the reasons for such changes. If USEPA has not
 1298 deducted the allowances from the previous year by August 31, the final

1299 report must be due, and all allowances required to be surrendered must be
 1300 surrendered, within 30 days after such deduction occurs.

1301
 1302 g) Notwithstanding 35 Ill. Adm. Code 201.146(hhh), until an EGU has complied
 1303 with the applicable emission standards of subsections (d) and (e) of this Section
 1304 for 12 months, the owner or operator of the EGU must obtain a construction
 1305 permit for any new or modified air pollution control equipment that it proposes to
 1306 construct for control of emissions of mercury, NO_x, or SO₂.

1307
 1308 (Source: Amended at 33 Ill. Reg. _____, effective _____)
 1309

1310 **Section 225.234 Temporary Technology-Based Standard for EGUs at Existing Sources**

1311
 1312 a) General.

1313
 1314 1) At a source with EGUs that commenced commercial operation on or
 1315 before December 31, 2008, for an EGU that meets the eligibility criteria in
 1316 subsection (b) of this Section, the owner or operator of the EGU may
 1317 temporarily comply with the requirements of this Section through June 30,
 1318 2015, as an alternative to compliance with the mercury emission standards
 1319 in Section 225.230, as provided in subsections (c), (d), and (e) of this
 1320 Section.

1321
 1322 2) An EGU that is complying with the emission control requirements of this
 1323 Subpart B by operating pursuant to this Section may not be included in a
 1324 compliance demonstration involving other EGUs during the period that is
 1325 operating pursuant to this Section.

1326
 1327 3) The owner or operator of an EGU that is complying with this Subpart B by
 1328 means of the temporary alternative emission standards of this Section is
 1329 not excused from any of the applicable monitoring, recordkeeping, and
 1330 reporting requirements set forth in Sections 225.240 through 225.290.

1331
 1332 4) Until June 30, 2012, as an alternative to the CEMS monitoring,
 1333 recordkeeping, and reporting requirements in Sections 225.240 through
 1334 225.290, the owner or operator of an EGU may elect to comply with the
 1335 emissions testing, monitoring, recordkeeping, and reporting requirements
 1336 in Section 225.239(c), (d), (e), (f)(1) and (2), (h)(2), (i)(3) and (4), and
 1337 (j)(1).

1338
 1339 b) Eligibility.
 1340 To be eligible to operate an EGU pursuant to this Section, the following criteria
 1341 must be met for the EGU:

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- 1) The EGU is equipped and operated with the air pollution control equipment or systems that include injection of halogenated activated carbon and either a cold-side electrostatic precipitator or a fabric filter.
 - 2) The owner or operator of the EGU is injecting halogenated activated carbon in an optimum manner for control of mercury emissions, which must include injection of Alstrom, Norit, Sorbent Technologies, Calgon Carbon's FLUEPAC MC Plus, or other halogenated activated carbon that the owner or operator of the EGU has demonstrated to have similar or better effectiveness for control of mercury emissions, at least at the following rates set forth in subsections (b)(2)(A) through (b)(2)(D) of this Section, unless other provisions for injection of halogenated activated carbon are established in a federally enforceable operating permit issued for the EGU, using an injection system designed for effective absorption of mercury, considering the configuration of the EGU and its ductwork. For the purposes of this subsection (b)(2), the flue gas flow rate must be determined for the point of sorbent injection (provided, however, that this flow rate may be assumed to be identical to the stack flow rate if the gas temperatures at the point of injection and the stack are normally within 100° F) or may otherwise be calculated from the stack flow rate, corrected for the difference in gas temperatures.
 - A) For an EGU firing subbituminous coal, 5.0 lbs per million actual cubic feet.
 - B) For an EGU firing bituminous coal, 10.0 lbs per million actual cubic feet.
 - C) For an EGU firing a blend of subbituminous and bituminous coal, a rate that is the weighted average of the above rates, based on the blend of coal being fired.
 - D) A rate or rates set on a unit-specific basis that are lower than the rate specified above to the extent that the owner or operator of the EGU demonstrates that such rate or rates are needed so that carbon injection would not increase particulate matter emissions or opacity so as to threaten compliance with applicable regulatory requirements for particulate matter or opacity.
 - 3) The total capacity of the EGUs that operate pursuant to this Section does not exceed the applicable of the following values:

- 1385 A) For the owner or operator of more than one existing source with
 1386 EGUs, 25 percent of the total rated capacity, in MW, of all the
 1387 EGUs at the existing sources that it owns or operates, other than
 1388 any EGUs operating pursuant to Section 225.235 of this Subpart B.
 1389
- 1390 B) For the owner or operator of only a single existing source with
 1391 EGUs (i.e., City, Water, Light & Power, City of Springfield, ID
 1392 167120AAO; Kincaid Generating Station, ID 021814AAB; and
 1393 Southern Illinois Power Cooperative/Marion Generating Station,
 1394 ID 199856AAC), 25 percent of the total rated capacity, in MW, of
 1395 the all the EGUs at the existing sources, other than any EGUs
 1396 operating pursuant to Section 225.235.
 1397
- 1398 c) Compliance Requirements.
 1399
- 1400 1) Emission Control Requirements.
 1401 The owner or operator of an EGU that is operating pursuant to this Section
 1402 must continue to maintain and operate the EGU to comply with the criteria
 1403 for eligibility for operation pursuant to this Section, except during an
 1404 evaluation of the current sorbent, alternative sorbents or other techniques
 1405 to control mercury emissions, as provided by subsection (e) of this
 1406 Section.
 1407
- 1408 2) Monitoring and Recordkeeping Requirements.
 1409 In addition to complying with all applicable monitoring and recordkeeping
 1410 reporting requirements in Sections 225.240 through 225.290 or Section
 1411 225.239(c), (d), (e), (f)(1) and (2), (h)(2), and i(3) and (4), the owner or
 1412 operator of an EGU operating pursuant to this Section must also:
 1413
- 1414 A) Through December 31, 2012, it must maintain records of the usage
 1415 of activated carbon, the exhaust gas flow rate from the EGU, and
 1416 the activated carbon feed rate, in pounds per million actual cubic
 1417 feet of exhaust gas at the injection point, on a weekly average.
 1418
- 1419 B) Beginning January 1, 2013, it must monitor activated carbon feed
 1420 rate to the EGU, flue gas temperature at the point of sorbent
 1421 injection, and exhaust gas flow rate from the EGU, automatically
 1422 recording this data and the activated carbon feed rate, in pounds
 1423 per million actual cubic feet of exhaust gas at the injection point,
 1424 on an hourly average.
 1425
- 1426 C) If a blend of bituminous and subbituminous coal is fired in the
 1427 EGU, it must maintain records of the amount of each type of coal

1428 burned and the required injection rate for injection of halogenated
 1429 activated carbon, on a weekly basis.

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3) Notification and Reporting Requirements.
 In addition to complying with all applicable reporting requirements in Sections 225.240 through 225.290 or Section 225.239(f)(1), (f)(2), and (j)(1), the owner or operator of an EGU operating pursuant to this Section must also submit the following notifications and reports to the Agency:

- A) Written notification prior to the month in which any of the following events will occur:
 - i) The EGU will no longer be eligible to operate under this Section due to a change in operation;
 - ii) The type of coal fired in the EGU will change; the mercury emission standard with which the owner or operator is attempting to comply for the EGU will change; or
 - iii) Operation under this Section will be terminated.
- B) Quarterly reports for the recordkeeping and monitoring or emissions testing conducted pursuant to subsection (c)(2) of this Section.
- C) Annual reports detailing activities conducted for the EGU to further improve control of mercury emissions, including the measures taken during the past year and activities planned for the current year.

d) Applications to Operate under the Technology-Based Standard

- 1) Application Deadlines.
 - A) The owner or operator of an EGU that is seeking to operate the EGU pursuant to this Section must submit an application to the Agency no later than three months prior to the date on which compliance with Section 225.230 of this Subpart B would otherwise have to be demonstrated. For example, the owner or operator of an EGU that is applying to operate the EGU pursuant to this Section on June 30, 2010, when compliance with applicable mercury emission standards must be first demonstrated, must apply by March 31, 2010 to operate under this Section.

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- B) Unless the Agency finds that the EGU is not eligible to operate pursuant to this Section or that the application for operation pursuant to this Section does not meet the requirements of subsection (d)(2) of this Section, the owner or operator of the EGU is authorized to operate the EGU pursuant to this Section beginning 60 days after receipt of the application by the Agency.

- C) The owner or operator of an EGU operating pursuant to this Section must reapply to operate pursuant to this Section:
 - i) If it operated the EGU pursuant to this Section 225.234 during the period of June 2010 through December 2012 and it seeks to operate the EGU pursuant to this Section 225.234 during the period from January 2013 through June 2015.

 - ii) If it is planning a physical change to or a change in the method of operation of the EGU, control equipment or practices for injection of activated carbon that is expected to reduce the level of control of mercury emissions.

- 2) Contents of Application.

An application to operate an EGU pursuant to this Section 225.234 must be submitted as an application for a new or revised federally enforceable operating permit for the EGU, and it must include the following documents and information:

 - A) A formal request to operate pursuant to this Section showing that the EGU is eligible to operate pursuant to this Section and describing the reason for the request, the measures that have been taken for control of mercury emissions, and factors preventing more effective control of mercury emissions from the EGU.

 - B) The applicable mercury emission standard in Section 225.230(a) with which the owner or operator of the EGU is attempting to comply and a summary of relevant mercury emission data for the EGU.

 - C) If a unit-specific rate or rates for carbon injection are proposed pursuant to subsection (b)(2) of this Section, detailed information to support the proposed injection rates.

- 1514 D) An action plan describing the measures that will be taken while
1515 operating under this Section to improve control of mercury
1516 emissions. This plan must address measures such as evaluation of
1517 alternative forms or sources of activated carbon, changes to the
1518 injection system, changes to operation of the unit that affect the
1519 effectiveness of mercury absorption and collection, changes to the
1520 particulate matter control device to improve performance, and
1521 changes to other emission control devices. For each measure
1522 contained in the plan, the plan must provide a detailed description
1523 of the specific actions that are planned, the reason that the measure
1524 is being pursued and the range of improvement in control of
1525 mercury that is expected, and the factors that affect the timing for
1526 carrying out the measure, together with the current schedule for the
1527 measure.
1528
- 1529 e) Evaluation of Alternative Control Techniques for Mercury Emissions.
1530
- 1531 1) During an evaluation of the effectiveness of the current sorbent,
1532 alternative sorbent, or other technique to control mercury emissions, the
1533 owner or operator of an EGU operating pursuant to this Section need not
1534 comply with the eligibility criteria for operation pursuant to this Section as
1535 needed to carry out an evaluation of the practicality and effectiveness of
1536 such technique, subject to the following limitations:
1537
- 1538 A) The owner or operator of the EGU must conduct the evaluation in
1539 accordance with a formal evaluation program that it has submitted
1540 to the Agency at least 30 days prior to beginning the evaluation.
1541
- 1542 B) The duration and scope of the formal evaluation program must not
1543 exceed the duration and scope reasonably needed to complete the
1544 desired evaluation of the alternative control technique, as initially
1545 addressed by the owner or owner in a support document that it has
1546 submitted with the formal evaluation program pursuant to
1547 subsection (e)(1)(A) of this Section.
1548
- 1549 C) Notwithstanding 35 Ill. Adm. Code 201.146(hhh), the owner or
1550 operator of the EGU must obtain a construction permit for any new
1551 or modified air pollution control equipment to be constructed as
1552 part of the evaluation of the alternative control technique.
1553
- 1554 D) The owner or operator of the EGU must submit a report to the
1555 Agency, no later than 90 days after the conclusion of the formal

1556 evaluation program describing the evaluation that was conducted,
1557 and providing the results of the formal evaluation program.
1558

1559 2) If the evaluation of the alternative control technique shows less effective
1560 control of mercury emissions from the EGU than achieved with the prior
1561 control technique, the owner or operator of the EGU must resume use of
1562 the prior control technique. If the evaluation of the alternative control
1563 technique shows comparable control effectiveness, the owner or operator
1564 of the EGU may either continue to use the alternative control technique in
1565 an optimum manner or resume use of the prior control technique. If the
1566 evaluation of the alternative control technique shows more effective
1567 control of mercury emissions, the owner or operator of the EGU must
1568 continue to use the alternative control technique in an optimum manner, if
1569 it continues to operate pursuant to this Section.
1570

1571 (Source: Amended at 33 Ill. Reg. _____, effective _____)
1572

1573 **Section 225.235 Units Scheduled for Permanent Shut Down**
1574

1575 a) The emission standards of Section 225.230(a) are not applicable to an EGU that
1576 will be permanently shut down as described in this Section:
1577

1578 1) The owner or operator of an EGU that relies on this Section must
1579 complete the following actions before June 30, 2009:
1580

1581 A) Have notified the Agency that it is planning to permanently shut
1582 down the EGU by the applicable date specified in subsection (a)(3)
1583 or (4) of this Section. This notification must include a description
1584 of the actions that have already been taken to allow the shut down
1585 of the EGU and a description of the future actions that must be
1586 accomplished to complete the shut down of the EGU, with the
1587 anticipated schedule for those actions and the anticipated date of
1588 permanent shut down of the unit.
1589

1590 B) Have applied for a construction permit or be actively pursuing a
1591 federally enforceable agreement that requires the EGU to be
1592 permanently shut down in accordance with this Section.
1593

1594 C) Have applied for revisions to the operating permits for the EGU to
1595 include provisions that terminate the authorization to operate the
1596 unit in accordance with this Section.
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- 2) The owner or operator of an EGU that relies on this Section must, before June 30, 2010, complete the following actions:
 - A) Have obtained a construction permit or entered into a federally enforceable agreement as described in subsection (a)(1)(B) of this Section; or
 - B) Have obtained revised operating permits in accordance with subsection (a)(1)(C) of this Section.

 - 3) The plan for permanent shut down of the EGU must provide for the EGU to be permanently shut down by no later than the applicable date specified below:
 - A) If the owner or operator of the EGU is not constructing a new EGU or other generating unit to specifically replace the existing EGU, by December 31, 2010.
 - B) If the owner or operator of the EGU is constructing a new EGU or other generating unit to specifically replace the existing EGU, by December 31, 2011.

 - 4) The owner or operator of the EGU must permanently shut down the EGU by the date specified in subsection (a)(3) of this Section, unless the owner or operator submits a demonstration to the Agency before the specified date showing that circumstances beyond its reasonable control (such as protracted delays in construction activity, unanticipated outage of another EGU, or protracted shakedown of a replacement unit) have occurred that interfere with the plan for permanent shut down of the EGU, in which case the Agency may accept the demonstration as substantiated and extend the date for shut down of the EGU as follows:
 - A) If the owner or operator of the EGU is not constructing a new EGU or other generating unit to specifically replace the existing EGU, for up to one year, i.e., permanent shut down of the EGU to occur by no later than December 31, 2011; or
 - B) If the owner or operator of the EGU is constructing a new EGU or other generating unit to specifically replace the existing EGU, for up to 18 months, i.e., permanent shutdown of the EGU to occur by no later than June 30, 2013; provided, however, that after December 31, 2012, the existing EGU must only operate as a back-

1640 up unit to address periods when the new generating units are not in
 1641 service.
 1642

1643 b) Notwithstanding Sections 225.230 and 225.232, any EGU that is not required to
 1644 comply with Section 225.230 pursuant to this Section must not be included when
 1645 determining whether any other EGUs at the source or other sources are in
 1646 compliance with Section 225.230.
 1647

1648 c) If an EGU, for which the owner or operator of the source has relied upon this
 1649 Section in lieu of complying with Section 225.230(a) is not permanently shut
 1650 down as required by this Section, the EGU must be considered to be a new EGU
 1651 subject to the emission standards in Section 225.237(a) beginning in the month
 1652 after the EGU was required to be permanently shut down, in addition to any other
 1653 penalties that may be imposed for failure to permanently shut down the EGU in
 1654 accordance with this Section.
 1655

1656 d) An EGU that has completed the requirements of subsection (a) of this Section is
 1657 exempt from the monitoring and testing requirements in Sections 225.239 and
 1658 225.240.
 1659

1660 e) An EGU that is scheduled for permanent shut down pursuant to Section
 1661 225.294(b) is exempt from the monitoring and testing requirements in Sections
 1662 225.239 and 225.240.
 1663

1664 (Source: Amended at 33 Ill. Reg. _____, effective _____)
 1665

1666 **Section 225.237 Emission Standards for New Sources with EGUs**
 1667

1668 a) Standards.
 1669

1670 1) Except as provided in Sections 225.238 and 225.239, theThe owner or
 1671 operator of a source with one or more EGUs, but that previously had not
 1672 had any EGUs that commenced commercial operation before January 1,
 1673 2009, must comply with one of the following emission standards for each
 1674 EGU on a rolling 12-month basis:
 1675

1676 A) An emission standard of 0.0080 lb mercury/GWh gross electrical
 1677 output; or
 1678

1679 B) A minimum 90 percent reduction of input mercury.
 1680

1681 2) For this purpose, compliance may be demonstrated using the equations in
 1682 Section 225.230(a)(2), (a)(3), or (b)(2).

1683
 1684 b) The initial 12-month rolling period for which compliance with the emission
 1685 standards of subsection (a)(1) of this Section must be demonstrated for a new
 1686 EGU will commence on the date that the initial performance testing commences
 1687 under 40 CFR 60.8~~test for the mercury emission standard under 40 CFR 60.45a~~
 1688 ~~also commences~~. The CEMS required by this Subpart B for mercury emissions
 1689 from the EGU must be certified prior to this date. Thereafter, compliance must be
 1690 demonstrated on a rolling 12-month basis based on calendar months.
 1691

1692 (Source: Amended at 33 Ill. Reg. _____, effective _____)
 1693

1694 **Section 225.238 Temporary Technology-Based Standard for New Sources with EGUs**
 1695

1696 a) General.
 1697

- 1698 1) At a source with EGUs that previously had not had any EGUs that
 1699 commenced commercial operation before January 1, 2009, for an EGU
 1700 that meets the eligibility criteria in subsection (b) of this Section, as an
 1701 alternative to compliance with the mercury emission standards in Section
 1702 225.237, the owner or operator of the EGU may temporarily comply with
 1703 the requirements of this Section, through December 31, 2018, as further
 1704 provided in subsections (c), (d), and (e) of this Section.
 1705
- 1706 2) An EGU that is complying with the emission control requirements of this
 1707 Subpart B by operating pursuant to this Section may not be included in a
 1708 compliance demonstration involving other EGUs at the source during the
 1709 period that the temporary technology-based standard is in effect.
 1710
- 1711 3) The owner or operator of an EGU that is complying with this Subpart B
 1712 pursuant to this Section is not excused from applicable monitoring,
 1713 recordkeeping, and reporting requirements of Sections 225.240 through
 1714 225.290.
 1715
- 1716 4) Until June 30, 2012, as an alternative to the CEMS monitoring,
 1717 recordkeeping, and reporting requirements in Sections 225.240 through
 1718 225.290, the owner or operator of an EGU may elect to comply with the
 1719 emissions testing, monitoring, recordkeeping, and reporting requirements
 1720 in Section 225.239(c), (d), (e), (f)(1) and (2), (h)(2), (i)(3) and (4), and
 1721 (j)(1).
 1722

1723 b) Eligibility.

1724 To be eligible to operate an EGU pursuant to this Section, the following criteria
 1725 must be met for the EGU:

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- 1) The EGU is subject to Best Available Control Technology (BACT) for emissions of sulfur dioxide, nitrogen oxides, and particulate matter, and the EGU is equipped and operated with the air pollution control equipment or systems specified below, as applicable to the category of EGU:
 - A) For coal-fired boilers, injection of sorbent or other mercury control technique (e.g., reagent) approved by the Agency.
 - B) For an EGU firing fuel gas produced by coal gasification, processing of the raw fuel gas prior to combustion for removal of mercury with a system using a sorbent or other mercury control technique approved by the Agency.

 - 2) For an EGU for which injection of a sorbent or other mercury control technique is required pursuant to subsection (b)(1) of this Section, the owner or operator of the EGU is injecting sorbent or other mercury control technique in an optimum manner for control of mercury emissions, which must include injection of Alstrom, Norit, Sorbent Technologies, Calgon Carbon's FLUEPAC MC Plus, or other sorbent or other mercury control technique that the owner or operator of the EGU demonstrates to have similar or better effectiveness for control of mercury emissions, at least at the rate set forth in the appropriate of subsections (b)(2)(A) through (b)(2)(C) of this Section, unless other provisions for injection of sorbent or other mercury control technique are established in a federally enforceable operating permit issued for the EGU, with an injection system designed for effective absorption of mercury. For the purposes of this subsection (b)(2), the flue gas flow rate must be determined for the point of sorbent injection or other mercury control technique (provided, however, that this flow rate may be assumed to be identical to the stack flow rate if the gas temperatures at the point of injection and the stack are normally within 100° F), or the flow rate may otherwise be calculated from the stack flow rate, corrected for the difference in gas temperatures.
 - A) For an EGU firing subbituminous coal, 5.0 pounds per million actual cubic feet.
 - B) For an EGU firing bituminous coal, 10.0 pounds per million actual cubic feet.
 - C) For an EGU firing a blend of subbituminous and bituminous coal, a rate that is the weighted average of the above rates, based on the blend of coal being fired.

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D) A rate or rates set on a unit-specific basis that are lower than the rate specified in subsections (b)(2)(A), (B), and (C) of this Section, to the extent that the owner or operator of the EGU demonstrates that such rate or rates are needed so that sorbent injection or other mercury control technique would not increase particulate matter emissions or opacity so as to threaten compliance with applicable regulatory requirements for particulate matter or opacity or cause a safety issue.

c) Compliance Requirements.

1) Emission Control Requirements.

The owner or operator of an EGU that is operating pursuant to this Section must continue to maintain and operate the EGU to comply with the criteria for eligibility for operation under this Section, except during an evaluation of the current sorbent, alternative sorbents, or other techniques to control mercury emissions, as provided by subsection (e) of this Section.

2) Monitoring and Recordkeeping Requirements.

In addition to complying with all applicable monitoring and recordkeeping requirements in Sections 225.240 through 225.290 or Section 225.239(c), (d), (e), (f)(1) and (2), (h)(2), and (i)(3) and (4), the owner or operator of a new EGU operating pursuant to this Section must also:

A) Monitor sorbent feed rate to the EGU, flue gas temperature at the point of sorbent injection or other mercury control technique, and exhaust gas flow rate from the EGU, automatically recording this data and the sorbent feed rate, in pounds per million actual cubic feet of exhaust gas at the injection point, on an hourly average.

B) If a blend of bituminous and subbituminous coal is fired in the EGU, maintain records of the amount of each type of coal burned and the required injection rate for injection of sorbent, on a weekly basis.

C) If a mercury control technique other than sorbent injection is approved by the Agency, monitor appropriate parameter for that control technique as specified by the Agency.

3) Notification and Reporting Requirements.

1811 In addition to complying with all applicable reporting requirements of
 1812 Sections 225.240 through 225.290 or Section 225.239(f)(1) and (2) and
 1813 (j)(1), the owner or operator of an EGU operating pursuant to this Section
 1814 must also submit the following notifications and reports to the Agency:
 1815

1816 A) Written notification prior to the month in which any of the
 1817 following events will occur: the EGU will no longer be eligible to
 1818 operate under this Section due to a change in operation; the type of
 1819 coal fired in the EGU will change; the mercury emission standard
 1820 with which the owner or operator is attempting to comply for the
 1821 EGU will change; or operation under this Section will be
 1822 terminated.
 1823

1824 B) Quarterly reports for the recordkeeping and monitoring or
 1825 emissions testing conducted pursuant to subsection (c)(2) of this
 1826 Section.
 1827

1828 C) Annual reports detailing activities conducted for the EGU to
 1829 further improve control of mercury emissions, including the
 1830 measures taken during the past year and activities planned for the
 1831 current year.
 1832

1833 d) Applications to Operate under the Technology-Based Standard.
 1834

1835 1) Application Deadlines.
 1836

1837 A) The owner or operator of an EGU that is seeking to operate the
 1838 EGU pursuant to this Section must submit an application to the
 1839 Agency no later than three months prior to the date that
 1840 compliance with Section 225.237 would otherwise have to be
 1841 demonstrated.
 1842

1843 B) Unless the Agency finds that the EGU is not eligible to operate
 1844 pursuant to this Section or that the application for operation under
 1845 this Section does not meet the requirements of subsection (d)(2) of
 1846 this Section, the owner or operator of the EGU is authorized to
 1847 operate the EGU pursuant to this Section beginning 60 days after
 1848 receipt of the application by the Agency.
 1849

1850 C) The owner or operator of an EGU operating pursuant to this
 1851 Section must reapply to operate pursuant to this Section if it is
 1852 planning a physical change to or a change in the method of
 1853 operation of the EGU, control equipment, or practices for injection

1854 of sorbent or other mercury control technique that is expected to
1855 reduce the level of control of mercury emissions.
1856

1857 2) Contents of Application.

1858 An application to operate pursuant to this Section must be submitted as an
1859 application for a new or revised federally enforceable operating permit for
1860 the new EGU, and it must include the following information:
1861

1862 A) A formal request to operate pursuant to this Section showing that
1863 the EGU is eligible to operate pursuant to this Section and
1864 describing the reason for the request, the measures that have been
1865 taken for control of mercury emissions, and factors preventing
1866 more effective control of mercury emissions from the EGU.
1867

1868 B) The applicable mercury emission standard in Section 225.237 with
1869 which the owner or operator of the EGU is attempting to comply
1870 and a summary of relevant mercury emission data for the EGU.
1871

1872 C) If a unit-specific rate or rates for sorbent or other mercury control
1873 technique injection are proposed pursuant to subsection (b)(2) of
1874 this Section, detailed information to support the proposed injection
1875 rates.
1876

1877 D) An action plan describing the measures that will be taken while
1878 operating pursuant to this Section to improve control of mercury
1879 emissions. This plan must address measures such as evaluation of
1880 alternative forms or sources of sorbent or other mercury control
1881 technique, changes to the injection system, changes to operation of
1882 the unit that affect the effectiveness of mercury absorption and
1883 collection, and changes to other emission control devices. For
1884 each measure contained in the plan, the plan must provide a
1885 detailed description of the specific actions that are planned, the
1886 reason that the measure is being pursued and the range of
1887 improvement in control of mercury that is expected, and the factors
1888 that affect the timing for carrying out the measure, with the current
1889 schedule for the measure.
1890

1891 e) Evaluation of Alternative Control Techniques for Mercury Emissions.
1892

1893 1) During an evaluation of the effectiveness of the current sorbent,
1894 alternative sorbent, or other technique to control mercury emissions, the
1895 owner or operator of an EGU operating pursuant to this Section does not
1896 need to comply with the eligibility criteria for operation pursuant to this

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Section as needed to carry out an evaluation of the practicality and effectiveness of such technique, further subject to the following limitations:

- A) The owner or operator of the EGU must conduct the evaluation in accordance with a formal evaluation program that it has submitted to the Agency at least 30 days prior to beginning the evaluation.
 - B) The duration and scope of the formal evaluation program must not exceed the duration and scope reasonably needed to complete the desired evaluation of the alternative control technique, as initially addressed by the owner or operator in a support document that it has submitted with the formal evaluation program pursuant to subsection (e)(1)(A) of this Section.
 - C) Notwithstanding 35 Ill. Adm. Code 201.146(hhh), the owner or operator of the EGU must obtain a construction permit for any new or modified air pollution control equipment to be constructed as part of the evaluation of the alternative control technique.
 - D) The owner or operator of the EGU must submit a report to the Agency no later than 90 days after the conclusion of the formal evaluation program describing the evaluation that was conducted and providing the results of the formal evaluation program.
- 2) If the evaluation of the alternative control technique shows less effective control of mercury emissions from the EGU than was achieved with the prior control technique, the owner or operator of the EGU must resume use of the prior control technique. If the evaluation of the alternative control technique shows comparable effectiveness, the owner or operator of the EGU may either continue to use the alternative control technique in an optimum manner or resume use of the prior control technique. If the evaluation of the alternative control technique shows more effective control of mercury emissions, the owner or operator of the EGU must continue to use the alternative control technique in an optimum manner, if it continues to operate pursuant to this Section.

(Source: Amended at 33 Ill. Reg. _____, effective _____)

Section 225.239 Periodic Emissions Testing Alternative Requirements

- a) General.

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- 1) As an alternative to demonstrating compliance with the emissions standards of Sections 225.230(a) or 225.237(a), the owner or operator of an EGU may elect to demonstrate compliance pursuant to the emission standards in subsection (b) of this Section and the use of quarterly emissions testing as an alternative to the use of CEMS;
- 2) The owner or operator of an EGU that elects to demonstrate compliance pursuant to this Section must comply with the testing, recordkeeping, and reporting requirements of this Section in addition to other applicable recordkeeping and reporting requirements in this Subpart;
- 3) The alternative method of compliance provided under this subsection may only be used until June 30, 2012, after which a CEMS certified in accordance with Section 225.250 of this Subpart B must be used.
- 4) If an owner or operator of an EGU demonstrating compliance pursuant to Section 225.230 or 225.237 discontinues use of CEMS before collecting a full 12 months of CEMS data and elects to demonstrate compliance pursuant to this Section, the data collected prior to that point must be averaged to determine compliance for such period. In such case, for purposes of calculating an emission standard or mercury control efficiency using the equations in Section 225.230(a) or (b), the "12" in the equations will be replaced by a variable equal to the number of full and partial months for which the owner or operator collected CEMS data.

b) Emission Limits.

- 1) Existing Units: Beginning July 1, 2009, the owner or operator of a source with one or more EGUs subject to this Subpart B that commenced commercial operation on or before June 30, 2009, must comply with one of the following standards for each EGU, as determined through quarterly emissions testing according to subsections (c), (d), (e), and (f) of this Section:
 - A) An emission standard of 0.0080 lb mercury/GWh gross electrical output; or
 - B) A minimum 90-percent reduction of input mercury.
- 2) New Units: Beginning within the first 2,160 hours after the commencement of commercial operations, the owner or operator of a source with one or more EGUs subject to this Subpart B that commenced commercial operation after June 30, 2009, must comply with one of the

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following standards for each EGU, as determined through quarterly emissions testing in accordance with subsections (c), (d), (e), and (f) of this Section:

- A) An emission standard of 0.0080 lb mercury/GWh gross electrical output; or
- B) A minimum 90-percent reduction of input mercury.

c) Initial Emissions Testing Requirements for New Units. The owner or operator of an EGU that commenced commercial operation after June 30, 2009, and that is complying by means of this Section must conduct an initial performance test in accordance with the requirements of subsections (d) and (e) of this Section within the first 2,160 hours after the commencement of commercial operations.

d) Emissions Testing Requirements

- 1) Subsequent to the initial performance test, emissions tests must be performed on a quarterly calendar basis in accordance with the requirements of subsections (d), (e), and (f) of this Section;
- 2) Notwithstanding the provisions in subsection (d)(1), owners or operators of EGUs demonstrating compliance under Section 225.233 or Sections 225.291 through 225.299 must perform emissions testing on a semi-annual calendar basis, where the periods consist of the months of January through June and July through December, in accordance with the requirements of subsections (d), (e), and (f)(1) and (2) of this Section;
- 3) Emissions tests which demonstrate compliance with this Subpart must be performed at least 45 days apart. However, if an emissions test fails to demonstrate compliance with this Subpart or the emissions test is being performed subsequent to a significant change in the operations of an EGU under subsection (h)(2) of this Section, the owner or operator of an EGU may perform additional emissions tests using the same test protocol previously submitted in the same period, with less than 45 days in between emissions tests;
- 4) A minimum of three and a maximum of nine emissions test runs, lasting at least one hour each, shall be conducted and averaged to determine compliance. All test runs performed will be reported.
- 5) If the EGU shares a common stack with one or more other EGUs, the owner or operator of the EGU will conduct emissions testing in the duct to

2026 the common stack from each unit, unless the owner or operator of the
2027 EGU considers the combined emissions measured at the common stack as
2028 the mass emissions of mercury for the EGUs for recordkeeping and
2029 compliance purposes.

2030
2031 6) If an owner or operator of an EGU demonstrating compliance pursuant to
2032 this Section later elects to demonstrate compliance pursuant to the CEMS
2033 monitoring provisions in Section 225.240 of this Subpart, the owner or
2034 operator must comply with the emissions monitoring deadlines in Section
2035 225.240(b)(4) of this Subpart.

2036
2037 e) Emissions Testing Procedures

2038
2039 1) The owner or operator must conduct a compliance test in accordance with
2040 Method 29, 30A, or 30B of 40 CFR 60, Appendix A, as incorporated by
2041 reference in Section 225.140;

2042
2043 2) Mercury emissions or control efficiency must be measured while the
2044 affected unit is operating at or above 90% of peak load;

2045
2046 3) For units complying with the control efficiency standard of subsection
2047 (b)(1)(B) or (b)(2)(B) of this Section, the owner or operator must perform
2048 coal sampling as follows:

2049
2050 A) in accordance with Section 225.265 of this Subpart at least once
2051 during each day of testing; and

2052
2053 B) in accordance with Section 225.265 of this Subpart, once each
2054 month in those months when emissions testing is not performed;

2055
2056 4) For units complying with the output-based emission standard of
2057 subsection (b)(1)(A) or (b)(2)(A) of this Section, the owner or operator
2058 must monitor gross electrical output for the duration of the testing.

2059
2060 5) The owner or operator of an EGU may use an alternative emissions testing
2061 method if such alternative is submitted to the Agency in writing and
2062 approved in writing by the Manager of the Bureau of Air's Compliance
2063 Section.

2064
2065 f) Notification Requirements

2066
2067 1) The owner or operator of an EGU must submit a testing protocol as
2068 described in USEPA's Emission Measurement Center's Guideline

- 2069 Document #42 to the Agency at least 45 days prior to a scheduled
 2070 emissions test, except as provided in Section 225.239(h)(2) and (h)(3).
 2071 Upon written request directed to the Manager of the Bureau of Air's
 2072 Compliance Section, the Agency may, in its sole discretion, waive the 45-
 2073 day requirement. Such waiver shall only be effective if it is provided in
 2074 writing and signed by the Manager of the Bureau of Air's Compliance
 2075 Section, or his or her designee;
 2076
- 2077 2) Notification of a scheduled emissions test must be submitted to the
 2078 Agency in writing, directed to the Manager of the Bureau of Air's
 2079 Compliance Section, at least 30 days prior to the expected date of the
 2080 emissions test. Upon written request directed to the Manager of the Bureau
 2081 of Air's Compliance Section, the Agency may, in its sole discretion,
 2082 wave the 30-day notification requirement. Such waiver shall only be
 2083 effective if it is provided in writing and signed by the Manager of the
 2084 Bureau of Air's Compliance Section, or his or her designee. Notification of
 2085 the actual date and expected time of testing must be submitted in writing,
 2086 directed to the Manager of the Bureau of Air's Compliance Section, at
 2087 least five working days prior to the actual date of the test;
 2088
- 2089 3) For an EGU that has elected to demonstrate compliance by use of the
 2090 emission standards of subsection (b) of this Section, if an emissions test
 2091 performed under the requirements of this Section fails to demonstrate
 2092 compliance with the limits of subsection (b) of this Section, the owner or
 2093 operator of an EGU may perform a new emissions test using the same test
 2094 protocol previously submitted in the same period, by notifying the
 2095 Manager of the Bureau of Air's Compliance Section or his or her designee
 2096 of the actual date and expected time of testing at least five working days
 2097 prior to the actual date of the test. The Agency may, in its sole discretion,
 2098 wave this five-day notification requirement. Such waiver shall only be
 2099 effective if it is provided in writing and signed by the Manager of the
 2100 Bureau of Air's Compliance Section, or his or her designee;
 2101
- 2102 4) In addition to the testing protocol required by subsection (f)(1) of this
 2103 Section, the owner or operator of an EGU that has elected to demonstrate
 2104 compliance by use of the emission standards of subsection (b) of this
 2105 Section must submit a Continuous Parameter Monitoring Plan to the
 2106 Agency at least 45 days prior to a scheduled emissions test. Upon written
 2107 request directed to the Manager of the Bureau of Air's Compliance
 2108 Section, the Agency may, in its sole discretion, waive the 45-day
 2109 requirement. Such waiver shall only be effective if it is provided in writing
 2110 and signed by the Manager of the Bureau of Air's Compliance Section, or
 2111 his or her designee. The Continuous Parameter Monitoring Plan must

2112 detail how the EGU will continue to operate within the parameters
 2113 enumerated in the testing protocol and how those parameters will ensure
 2114 compliance with the applicable mercury limit. For example, the
 2115 Continuous Parameter Monitoring Plan must include coal sampling as
 2116 described in Section 225.239(e)(3) of this Subpart and must ensure that an
 2117 EGU that performs an emissions test using a blend of coals continues to
 2118 operate using that same blend of coal. If the Agency disapproves the
 2119 Continuous Parameter Monitoring Plan, the owner or operator of the EGU
 2120 has 30 days from the date of receipt of the disapproval to submit more
 2121 detailed information in accordance with the Agency's request.
 2122

2123 g) Compliance Determination
 2124

- 2125 1) Each quarterly emissions test shall determine compliance with this
 2126 Subpart for that quarter, where the quarterly periods consist of the months
 2127 of January through March, April through June, July through September,
 2128 and October through December;
 2129
 2130 2) If emissions testing conducted pursuant to this Section fails to demonstrate
 2131 compliance, the owner or operator of the EGU will be deemed to have
 2132 been out of compliance with this Subpart beginning on the day after the
 2133 most recent emissions test that demonstrated compliance or the last day of
 2134 certified CEMS data demonstrating compliance on a rolling 12-month
 2135 basis, and the EGU will remain out of compliance until a subsequent
 2136 emissions test successfully demonstrates compliance with the limits of this
 2137 Section.
 2138

2139 h) Operation Requirements
 2140

- 2141 1) The owner or operator of an EGU that has elected to demonstrate
 2142 compliance by use of the emission standards of subsection (b) of this
 2143 Section must continue to operate the EGU commensurate with the
 2144 Continuous Parameter Monitoring Plan until another Continuous
 2145 Parameter Monitoring Plan is developed and submitted to the Agency in
 2146 conjunction with the next compliance demonstration, in accordance with
 2147 subsection (f)(4) of this Section.
 2148
 2149 2) If the owner or operator makes a significant change to the operations of an
 2150 EGU subject to this Section, such as changing from bituminous to
 2151 subbituminous coal, the owner or operator must submit a testing protocol
 2152 to the Agency and perform an emissions test within seven operating days
 2153 of the significant change. In addition, the owner or operator of an EGU
 2154 that has elected to demonstrate compliance by use of the emission

2155 standards of subsection (b) of this Section must submit a Continuous
 2156 Parameter Monitoring Plan within seven operating days of the significant
 2157 change.

2158
 2159 3) If a blend of bituminous and subbituminous coal is fired in the EGU, the
 2160 owner or operator of the EGU must ensure that the EGU continues to
 2161 operate using the same blend that was used during the most recent
 2162 successful emissions test. If the blend of coal changes, the owner or
 2163 operator of the EGU must re-test in accordance with subsections (d), (e),
 2164 (f), and (g) of this Section within 30 days of the change in coal blend,
 2165 notwithstanding the requirement of subsection (d)(3) of this Section that
 2166 there must be 45 days between emissions tests.

2167
 2168 i) recordkeeping

2169
 2170 1) The owner or operator of an EGU and its designated representative must
 2171 comply with all applicable recordkeeping and reporting requirements in
 2172 this Section.

2173
 2174 2) Continuous Parameter Monitoring. The owner or operator of an EGU
 2175 must maintain records to substantiate that the EGU is operating in
 2176 compliance with the parameters listed in the Continuous Parameter
 2177 Monitoring Plan, detailing the parameters that impact mercury reduction
 2178 and including the following records related to the emissions of mercury:

2179
 2180 A) For an EGU for which the owner or operator is complying with
 2181 this Subpart B pursuant to Section 225.239(b)(1)(B) or
 2182 225.239(b)(2)(B), records of the daily mercury content of coal
 2183 used (lbs/trillion Btu) and the daily and quarterly input mercury
 2184 (lbs).

2185
 2186 B) For an EGU for which the owner or operator of an EGU complying
 2187 with this Subpart B pursuant to Section 225.239(b)(1)(A) or
 2188 225.239(b)(2)(A), records of the daily and quarterly gross
 2189 electrical output (MWh) on an hourly basis.:

2190
 2191 3) The owner or operator of an EGU using activated carbon injection must
 2192 also comply with the following requirements:

2193
 2194 A) Maintain records of the usage of sorbent, the exhaust gas flow rate
 2195 from the EGU, and the sorbent feed rate, in pounds per million
 2196 actual cubic feet of exhaust gas at the injection point, on a weekly
 2197 average;

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- B) If a blend of bituminous and subbituminous coal is fired in the EGU, keep records of the amount of each type of coal burned and the required injection rate for injection of activated carbon, on a weekly basis.
- 4) The owner or operator of an EGU must retain all records required by this Section at the source unless otherwise provided in the CAAPP permit issued for the source and must make a copy of any record available to the Agency promptly upon request.
- 5) The owner or operator of an EGU demonstrating compliance pursuant to this Section must monitor and report the heat input rate at the unit level.
- 6) The owner or operator of an EGU demonstrating compliance pursuant to this Section must perform and report coal sampling in accordance with subsection 225.239(e)(3).

j) Reporting Requirements

- 1) An owner or operator of an EGU shall submit to the Agency a Final Source Test Report for each periodic emissions test within 45 days after the test is completed. The Final Source Test Report will be directed to the Manager of the Bureau of Air's Compliance Section, or his or her designee, and include at a minimum:
 - A) A summary of results;
 - B) A description of test methods, including a description of sampling points, sampling train, analysis equipment, and test schedule, and a detailed description of test conditions, including:
 - i) Process information, including but not limited to modes of operation, process rate, and fuel or raw material consumption;
 - ii) Control equipment information (i.e., equipment condition and operating parameters during testing);
 - iii) A discussion of any preparatory actions taken (i.e., inspections, maintenance, and repair); and

2240 iv) Data and calculations, including copies of all raw data
2241 sheets and records of laboratory analyses, sample
2242 calculations, and data on equipment calibration.
2243

2244 2) The owner or operator of a source with one or more EGUs demonstrating
2245 compliance with Subpart B in accordance with this Section must submit to
2246 the Agency a Quarterly Certification of Compliance within 45 days
2247 following the end of each calendar quarter. Quarterly certifications of
2248 compliance must certify whether compliance existed for each EGU for the
2249 calendar quarter covered by the certification. If the EGU failed to comply
2250 during the quarter covered by the certification, the owner or operator must
2251 provide the reasons the EGU or EGUs failed to comply and a full
2252 description of the noncompliance (i.e., tested emissions rate, coal sample
2253 data, etc.). In addition, for each EGU, the owner or operator must provide
2254 the following appropriate data to the Agency as set forth in this Section.
2255

2256 A) A list of all emissions tests performed within the calendar quarter
2257 covered by the Certification and submitted to the Agency for each
2258 EGU, including the dates on which such tests were performed.
2259

2260 B) Any deviations or exceptions each month and discussion of the
2261 reasons for such deviations or exceptions.
2262

2263 C) All Quarterly Certifications of Compliance required to be
2264 submitted must include the following certification by a responsible
2265 official:
2266

2267 I certify under penalty of law that this document and all
2268 attachments were prepared under my direction or supervision in
2269 accordance with a system designed to assure that qualified
2270 personnel properly gather and evaluate the information submitted.
2271 Based on my inquiry of the person or persons directly responsible
2272 for gathering the information, the information submitted is, to the
2273 best of my knowledge and belief, true, accurate, and complete. I
2274 am aware that there are significant penalties for submitting false
2275 information, including the possibility of fine and imprisonment for
2276 knowing violations.
2277

2278 3) Deviation Reports. For each EGU, the owner or operator must promptly
2279 notify the Agency of deviations from any of the requirements of this
2280 Subpart B. At a minimum, these notifications must include a description
2281 of such deviations within 30 days after discovery of the deviations, and a

2282 discussion of the possible cause of such deviations, any corrective actions,
 2283 and any preventative measures taken.

2284
 2285 (Source: Added at 33 Ill. Reg. _____, effective _____)
 2286

2287 **Section 225.240 General Monitoring and Reporting Requirements**
 2288

2289 The owner or operator of an EGU must comply with the monitoring, recordkeeping, and
 2290 reporting requirements as provided in this Section, Sections 225.250 through 225.290 of this
 2291 Subpart B, and Sections 1.14 through 1.18 of Appendix B to this PartSubpart I of 40 CFR 75
 2292 (sections 75.80 through 75.84), incorporated by reference in Section 225.140. If the EGU
 2293 utilizes a common stack with units that are not EGUs and the owner or operator of the EGU does
 2294 not conduct emissions monitoring in the duct to the common stack from each EGU, the owner or
 2295 operator of the EGU must conduct emissions monitoring in accordance with Section 1.16(b)(2)
 2296 of Appendix B to this Part 40 CFR 75.82(b)(2) and this Section, including monitoring in the duct
 2297 to the common stack from each unit that is not an EGU, unless the owner or operator of the EGU
 2298 counts the combined emissions measured at the common stack as the mass emissions of mercury
 2299 for the EGUs for recordkeeping and compliance purposes.

- 2300
- 2301 a) Requirements for installation, certification, and data accounting. The owner or
 2302 operator of each EGU must:
- 2303
 - 2304 1) Install all monitoring systems required pursuant to this Section and
 2305 Sections 225.250 through 225.290 for monitoring mercury mass emissions
 2306 (including all systems required to monitor mercury concentration, stack
 2307 gas moisture content, stack gas flow rate, and CO₂ or O₂ concentration, as
 2308 applicable, in accordance with Sections 1.15 and 1.16 of Appendix B to
 2309 this Part40 CFR 75.81 and 75.82).
 - 2310
 - 2311 2) Successfully complete all certification tests required pursuant to Section
 2312 225.250 and meet all other requirements of this Section, Sections 225.250
 2313 through 225.290, and Sections 1.14 through 1.18 of Appendix B to this
 2314 Part subpart I of 40 CFR 75 applicable to the monitoring systems required
 2315 under subsection (a)(1) of this Section.
 - 2316
 - 2317 3) Record, report, and assure the quality of the data from the monitoring
 2318 systems required under subsection (a)(1) of this Section.
 - 2319
 - 2320 4) If the owner or operator elects to use the low mass emissions excepted
 2321 monitoring methodology for an EGU that emits no more than 464 ounces
 2322 (29 pounds) of mercury per year pursuant to Section 1.15(b) of Appendix
 2323 B to this Part40 CFR 75.81(b), it must perform emissions testing in
 2324 accordance with Section 1.15(c) of Appendix B to this Part 40 CFR

2325 ~~75.81(e)~~ to demonstrate that the EGU is eligible to use this excepted
 2326 emissions monitoring methodology, as well as comply with all other
 2327 applicable requirements of Section 1.15(b) through (f) of Appendix B to
 2328 this Part 40 CFR 75.81(b) through (f). Also, the owner or operator must
 2329 submit a copy of any information required to be submitted to the USEPA
 2330 pursuant to these provisions to the Agency. The initial emissions testing
 2331 to demonstrate eligibility of an EGU for the low mass emissions excepted
 2332 methodology must be conducted by the applicable of the following dates:
 2333

- 2334 A) If the EGU has commenced commercial operation before July 1,
 2335 2008, at least by ~~July~~January 1, 2009, or 45 days prior to relying
 2336 on the low mass emissions excepted methodology, whichever date
 2337 is later.
- 2338
- 2339 B) If the EGU has commenced commercial operation on or after July
 2340 1, 2008, at least 45 days prior to the applicable date specified
 2341 pursuant to subsection (b)(2) of this Section or 45 days prior to
 2342 relying on the low mass emissions excepted methodology,
 2343 whichever date is later.
- 2344

2345 b) Emissions Monitoring Deadlines. The owner or operator must meet the emissions
 2346 monitoring system certification and other emissions monitoring requirements of
 2347 subsections (a)(1) and (a)(2) of this Section on or before the applicable of the
 2348 following dates. The owner or operator must record, report, and quality-assure
 2349 the data from the emissions monitoring systems required under subsection (a)(1)
 2350 of this Section on and after the applicable of the following dates:

- 2351
- 2352 1) For the owner or operator of an EGU that commences commercial
 2353 operation before July 1, 2008, by ~~July~~January 1, 2009.
- 2354
- 2355 2) For the owner or operator of an EGU that commences commercial
 2356 operation on or after July 1, 2008, by 90 unit operating days or 180
 2357 calendar days, whichever occurs first, after the date on which the EGU
 2358 commences commercial operation.
- 2359
- 2360 3) For the owner or operator of an EGU for which construction of a new
 2361 stack or flue or installation of add-on mercury emission controls, a flue
 2362 gas desulfurization system, a selective catalytic reduction system, a fabric
 2363 filter, or a compact hybrid particulate collector system is completed after
 2364 the applicable deadline pursuant to subsection (b)(1) or (b)(2) of this
 2365 Section, by 90 unit operating days or 180 calendar days, whichever occurs
 2366 first, after the date on which emissions first exit to the atmosphere through
 2367 the new stack or flue, add-on mercury emission controls, flue gas

2368 desulfurization system, selective catalytic reduction system, fabric filter,
 2369 or compact hybrid particulate collector system.

2370
 2371 4) For an owner or operator of an EGU that originally elected to demonstrate
 2372 compliance pursuant to the emissions testing requirements in Section
 2373 225.239, by the first day of the calendar quarter following the last
 2374 emissions test demonstrating compliance with Section 225.239.

2375
 2376 c) Reporting Data.

2377
 2378 1) Except as provided in subsection (c)(2) of this Section, the owner or
 2379 operator of an EGU that does not meet the applicable emissions
 2380 monitoring date set forth in subsection (b) of this Section for any
 2381 emissions monitoring system required pursuant to subsection (a)(1) of this
 2382 Section must begin periodic emissions testing in accordance with Section
 2383 225.239, for each such monitoring system, determine, record, and report
 2384 the maximum potential (or, as appropriate, the minimum potential) values
 2385 for mercury concentration, the stack gas flow rate, the stack gas moisture
 2386 content, and any other parameters required to determine mercury mass
 2387 emissions in accordance with 40 CFR 75.80(g).

2388
 2389 2) The owner or operator of an EGU that does not meet the applicable
 2390 emissions monitoring date set forth in subsection (b)(3) of this Section for
 2391 any emissions monitoring system required pursuant to subsection (a)(1) of
 2392 this Section must begin periodic emissions testing in accordance with
 2393 Section 225.239, for each such monitoring system, determine, record, and
 2394 report substitute data using the applicable missing data procedures as set
 2395 forth in 40 CFR 75.80(f), in lieu of the maximum potential (or, as
 2396 appropriate, minimum potential) values for a parameter, if the owner or
 2397 operator demonstrates that there is continuity between the data streams for
 2398 that parameter before and after the construction or installation pursuant to
 2399 subsection (b)(3) of this Section.

2400
 2401 d) Prohibitions.

2402
 2403 1) No owner or operator of an EGU may use any alternative emissions
 2404 monitoring system, alternative reference method for measuring emissions,
 2405 or other alternative to the emissions monitoring and measurement
 2406 requirements of this Section and Sections 225.250 through 225.290, unless
 2407 such alternative is submitted to the Agency in writing and approved in
 2408 writing by the Manager of the Bureau of Air's Compliance Section, or his
 2409 or her designee promulgated by the USEPA and approved in writing by the

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~~Agency, or the use of such alternative is approved in writing by the Agency, and USEPA.~~

- 2) No owner or operator of an EGU may operate its EGU so as to discharge, or allow to be discharged, mercury emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this Section, Sections 225.250 through 225.290, and Sections 1.14 through 1.18 of Appendix B to this Part, unless demonstrating compliance pursuant to Section 225.239, as applicable~~subpart I of 40 CFR 75.~~

- 3) No owner or operator of an EGU may disrupt the CEMS, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording mercury mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this Section, Sections 225.250 through 225.290, and Sections 1.14 through 1.18 of Appendix B to this Part~~subpart I of 40 CFR 75.~~

- 4) No owner or operator of an EGU may retire or permanently discontinue use of the CEMS or any component thereof, or any other approved monitoring system pursuant to this Subpart B, except under any one of the following circumstances:
 - A) The owner or operator is monitoring emissions from the EGU with another certified monitoring system that has been approved, in accordance with the applicable provisions of this Section, Sections 225.250 through 225.290 of this Subpart B, and Sections 1.14 through 1.18 of Appendix B to this Part~~subpart I of 40 CFR 75~~, by the Agency for use at that EGU and that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

 - B) The owner or operator or designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with Section 225.250(a)(3)(A).

 - C) The owner or operator is demonstrating compliance pursuant to the applicable subsections of Section 225.239.

- e) Long-term Cold Storage.

The owner or operator of an EGU that is in long-term cold storage is subject to the provisions of 40 CFR 75.4 and 40 CFR 75.64, incorporated by reference in Section 225.140, relating to monitoring, recordkeeping, and reporting for units in long-term cold storage.

(Source: Amended at 33 Ill. Reg. _____, effective _____)

Section 225.250 Initial Certification and Recertification Procedures for Emissions Monitoring

a) The owner or operator of an EGU must comply with the following initial certification and recertification procedures for a CEMS (i.e., a CEMS or an excepted monitoring system (sorbent trap monitoring system) pursuant to Section 1.3 of Appendix B to this Part40 CFR 75.15, incorporated by reference in Section 225.140) required by Section 225.240(a)(1). The owner or operator of an EGU that qualifies for, and for which the owner or operator elects to use, the low-mass-emissions excepted methodology pursuant to Section 1.15(b) of Appendix B to this Part40 CFR 75.81(b), incorporated by reference in Section 225.140, must comply with the procedures set forth in subsection (c) of this Section.

1) Requirements for Initial Certification. The owner or operator of an EGU must ensure that, for each CEMS required by Section 225.240(a)(1) (including the automated data acquisition and handling system), the owner or operator successfully completes all of the initial certification testing required pursuant to Section 1.4 of Appendix B to this Part40 CFR 75.80(d), incorporated by reference in Section 225.140, by the applicable deadline in Section 225.240(b). In addition, whenever the owner or operator of an EGU installs a monitoring system to meet the requirements of this Subpart B in a location where no such monitoring system was previously installed, the owner or operator must successfully complete the initial certification requirements of Section 1.4 of Appendix B to this Part40 CFR 75.80(d).

2) Requirements for Recertification. Whenever the owner or operator of an EGU makes a replacement, modification, or change in any certified CEMS, or an excepted monitoring system (sorbent trap monitoring system) pursuant to Section 1.3 of Appendix B to this Part40 CFR 75.15, and required by Section 225.240(a)(1), that may significantly affect the ability of the system to accurately measure or record mercury mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of Section 1.5 of Appendix B to this Part 40 CFR 75.24 or Exhibit B to Appendix B to this PartAppendix B to 40 CFR 75, each incorporated by reference in Section 225.140, the owner or operator

2496 of an EGU must recertify the monitoring system in accordance with
 2497 Section 1.4(b) of Appendix B to this Part40 CFR 75.20(b), incorporated
 2498 by reference in Section 225.140. Furthermore, whenever the owner or
 2499 operator of an EGU makes a replacement, modification, or change to the
 2500 flue gas handling system or the EGU's operation that may significantly
 2501 change the stack flow or concentration profile, the owner or operator must
 2502 recertify each CEMS, and each excepted monitoring system (sorbent trap
 2503 monitoring system) pursuant to Section 1.3 to Appendix B to this Part40
 2504 CFR 75.15, whose accuracy is potentially affected by the change, all in
 2505 accordance with Section 1.4(b) to Appendix B to this Part40 CFR
 2506 75.20(b). Examples of changes to a CEMS that require recertification
 2507 include, but are not limited to, replacement of the analyzer, complete
 2508 replacement of an existing CEMS, or change in location or orientation of
 2509 the sampling probe or site.

2510
 2511 3) Approval Process for Initial Certification and Recertification. Subsections
 2512 (a)(3)(A) through (a)(3)(D) of this Section apply to both initial
 2513 certification and recertification of a CEMS required by Section
 2514 225.240(a)(1). For recertifications, the words "certification" and "initial
 2515 certification" are to be read as the word "recertification", the word
 2516 "certified" is to be read as the word "recertified", and the procedures set
 2517 forth in Section 1.4(b)(5) of Appendix B to this Part 40 CFR 75.20(b)(5)
 2518 are to be followed in lieu of the procedures set forth in subsection
 2519 (a)(3)(E) of this Section.

2520
 2521 A) Notification of Certification. The owner or operator must submit
 2522 written notice of the dates of certification testing to the Agency
 2523 directed to the Manager of the Bureau of Air's Compliance
 2524 Section, USEPA Region 5, and the Administrator of the USEPA
 2525 written notice of the dates of certification testing, in accordance
 2526 with Section 225.270.

2527
 2528 B) Certification Application. The owner or operator must submit to
 2529 the Agency a certification application for each monitoring system.
 2530 A complete certification application must include the information
 2531 specified in 40 CFR 75.63, incorporated by reference in Section
 2532 225.140.

2533
 2534 C) Provisional Certification Date. The provisional certification date
 2535 for a monitoring system must be determined in accordance with
 2536 Section 1.4(a)(3) of Appendix B to this Part40 CFR 75.20(a)(3),
 2537 incorporated by reference in Section 225.140. A provisionally
 2538 certified monitoring system may be used pursuant to this Subpart B

for a period not to exceed 120 days after receipt by the Agency of the complete certification application for the monitoring system pursuant to subsection (a)(3)(B) of this Section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of Appendix B to this Part 40 CFR 75, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Agency does not invalidate the provisional certification by issuing a notice of disapproval within 120 days after the date of receipt by the Agency of the complete certification application.

D) Certification Application Approval Process. The Agency must issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days after receipt of the complete certification application required by subsection (a)(3)(B) of this Section. In the event the Agency does not issue a written notice of approval or disapproval within the 120-day period, each monitoring system that meets the applicable performance requirements of Appendix B to this Part 40 CFR 75 and which is included in the certification application will be deemed certified for use pursuant to this Subpart B.

i) Approval Notice. If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of Appendix B to this Part 40 CFR 75, then the Agency must issue a written notice of approval of the certification application within 120 days after receipt.

ii) Incomplete Application Notice. If the certification application is not complete, then the Agency must issue a written notice of incompleteness that sets a reasonable date by which the owner or operator must submit the additional information required to complete the certification application. If the owner or operator does not comply with the notice of incompleteness by the specified date, the Agency may issue a notice of disapproval pursuant to subsection (a)(3)(D)(iii) of this Section. The 120-day review period will not begin before receipt of a complete certification application.

iii) Disapproval Notice. If the certification application shows that any monitoring system does not meet the performance

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2582 requirements of Appendix B to this Part40 CFR 75, or if
 2583 the certification application is incomplete and the
 2584 requirement for disapproval pursuant to subsection
 2585 (a)(3)(D)(ii) of this Section is met, the Agency must issue a
 2586 written notice of disapproval of the certification
 2587 application. Upon issuance of such notice of disapproval,
 2588 the provisional certification is invalidated, and the data
 2589 measured and recorded by each uncertified monitoring
 2590 system will not be considered valid quality-assured data
 2591 beginning with the date and hour of provisional
 2592 certification (as defined pursuant to Section 1.4(a)(3) of
 2593 Appendix B to this Part40 CFR 75.20(a)(3)). The owner or
 2594 operator must follow the procedures for loss of certification
 2595 set forth in subsection (a)(3)(E) of this Section for each
 2596 monitoring system that is disapproved for initial
 2597 certification.
 2598

2599 iv) Audit Decertification. The Agency may issue a notice of
 2600 disapproval of the certification status of a monitor in
 2601 accordance with Section 225.260(b).
 2602

2603 E) Procedures for Loss of Certification. If the Agency issues a notice
 2604 of disapproval of a certification application pursuant to subsection
 2605 (a)(3)(D)(iii) of this Section or a notice of disapproval of
 2606 certification status pursuant to subsection (a)(3)(D)(iv) of this
 2607 Section, the owner or operator must fulfill the following
 2608 requirements:
 2609

2610 i) ~~The owner or operator must substitute the following values~~
 2611 ~~for each disapproved monitoring system and for each hour~~
 2612 ~~of EGU operation during the period of invalid data~~
 2613 ~~specified pursuant to 40 CFR 75.20(a)(4)(iii) or 75.21(e),~~
 2614 ~~continuing until the applicable date and hour specified~~
 2615 ~~pursuant to 40 CFR 75.20(a)(5)(i), each incorporated by~~
 2616 ~~reference in Section 225.140. For a disapproved mercury~~
 2617 ~~pollutant concentration monitor and disapproved flow~~
 2618 ~~monitor, respectively, the maximum potential concentration~~
 2619 ~~of mercury and the maximum potential flow rate, as~~
 2620 ~~defined in sections 2.1.7.1 and 2.1.4.1 of appendix A to 40~~
 2621 ~~CFR 75, incorporated by reference in Section 225.140. For~~
 2622 ~~a disapproved moisture monitoring system and disapproved~~
 2623 ~~diluent gas monitoring system, respectively, the minimum~~
 2624 ~~potential moisture percentage and either the maximum~~

2625 potential CO₂ concentration or the minimum potential O₂
 2626 concentration (as applicable), as defined in sections 2.1.5,
 2627 2.1.3.1, and 2.1.3.2 of appendix A to 40 CFR 75,
 2628 incorporated by reference in Section 225.140. For a
 2629 disapproved excepted monitoring system (sorber trap
 2630 monitoring system) pursuant to 40 CFR 75.15 and
 2631 disapproved flow monitor, respectively, the maximum
 2632 potential concentration of mercury and maximum potential
 2633 flow rate, as defined in sections 2.1.7.1 and 2.1.4.1 of
 2634 appendix A to 40 CFR 75, incorporated by reference in
 2635 Section 225.140.

2636
 2637 iii) The owner or operator must submit a notification of
 2638 certification retest dates and a new certification application
 2639 in accordance with subsections (a)(3)(A) and (B) of this
 2640 Section.

2641
 2642 iii) The owner or operator must repeat all certification tests or
 2643 other requirements that were failed by the monitoring
 2644 system, as indicated in the Agency's notice of disapproval,
 2645 no later than 30 unit operating days after the date of
 2646 issuance of the notice of disapproval.

2647
 2648 b) Exemption.

2649
 2650 1) If an emissions monitoring system has been previously certified in
 2651 accordance with Appendix B to this Part 40 CFR 75 and the applicable
 2652 quality assurance and quality control requirements of Section 1.5 and
 2653 Exhibit B to Appendix B to this Part 40 CFR 75.21 and appendix B to 40
 2654 CFR 75 are fully met, the monitoring system will be exempt from the
 2655 initial certification requirements of this Section.

2656
 2657 2) The recertification provisions of this Section apply to an emissions
 2658 monitoring system required by Section 225.240(a)(1) exempt from initial
 2659 certification requirements pursuant to subsection (a)(1) of this Section.

2660
 2661 c) Initial certification and recertification procedures for EGUs using the mercury low
 2662 mass emissions excepted methodology pursuant to Section 1.15(b) of Appendix B
 2663 to this Part 40 CFR 75.81(b). The owner or operator that has elected to use the
 2664 mercury-low-mass-emissions-excepted methodology for a qualified EGU
 2665 pursuant to Section 1.15(b) to Appendix B to this Part 40 CFR 75.81(b) must
 2666 meet the applicable certification and recertification requirements in Section

2667 1.15(c) through (f) to Appendix B to this Part 40 CFR 75.81(c) through (f),
2668 incorporated by reference in Section 225.140.
2669

- 2670 d) Certification Applications. The owner or operator of an EGU must submit an
2671 application to the Agency within 45 days after completing all initial certification
2672 or recertification tests required pursuant to this Section, including the information
2673 required pursuant to 40 CFR 75.63, incorporated by reference in Section 225.140.
2674

2675 (Source: Amended at 33 Ill. Reg. _____, effective _____)
2676

2677 **Section 225.260 Out of Control Periods and Data Availability for Emission Monitors**
2678

- 2679 a) Out of control periods must be determined in accordance with Section 1.7 of
2680 Appendix B.
2681

- 2682 ba) Monitor data availability must be determined on a calendar quarter basis in
2683 accordance with Section 1.8 of Appendix B. Whenever any emissions monitoring
2684 system fails to meet the quality assurance and quality control requirements or
2685 data validation requirements of 40 CFR 75, incorporated by reference in Section
2686 225.140, data must be substituted using the applicable missing data procedures in
2687 subparts D and I of 40 CFR 75, each incorporated by reference in Section 225.140
2688 following initial certification of the required CO₂, O₂, flow monitor, or mercury
2689 concentration or moisture monitoring system(s) at a particular unit or stack
2690 location. Compliance with the percent reduction standard in Section
2691 225.230(a)(1)(B) or 225.237(a)(1)(B) or the emissions concentration standard in
2692 Section 225.230(a)(1)(A) or 225.237(a)(1)(A) can only be demonstrated if the
2693 monitor data availability is equal to or greater than 75 percent; that is, quality
2694 assured data must be recorded by a certified primary monitor, a certified
2695 redundant or non-redundant backup monitor, or reference method for that unit at
2696 least 75 percent of the time the unit is in operation.
2697

- 2698 cb) Audit Decertification. Whenever both an audit of an emissions monitoring
2699 system and a review of the initial certification or recertification application reveal
2700 that any emissions monitoring system should not have been certified or recertified
2701 because it did not meet a particular performance specification or other
2702 requirement pursuant to Section 225.250 or the applicable provisions of Appendix
2703 B to this Part 40 CFR 75, both at the time of the initial certification or
2704 recertification application submission and at the time of the audit, the Agency
2705 must issue a notice of disapproval of the certification status of such monitoring
2706 system. For the purposes of this subsection (cb), an audit must be either a field
2707 audit or an audit of any information submitted to the Agency. By issuing the
2708 notice of disapproval, the Agency revokes prospectively the certification status of
2709 the emissions monitoring system. The data measured and recorded by the

2710 monitoring system must not be considered valid quality-assured data from the
 2711 date of issuance of the notification of the revoked certification status until the date
 2712 and time that the owner or operator completes subsequently approved initial
 2713 certification or recertification tests for the monitoring system. The owner or
 2714 operator must follow the applicable initial certification or recertification
 2715 procedures in Section 225.250 for each disapproved monitoring system.
 2716

2717 (Source: Amended at 33 Ill. Reg. _____, effective _____)
 2718

2719 **Section 225.261 Additional Requirements to Provide Heat Input Data**
 2720

2721 The owner or operator of an EGU that monitors and reports mercury mass emissions using a
 2722 mercury concentration monitoring system and a flow monitoring system must also monitor and
 2723 report the heat input rate at the EGU level using the procedures set forth in Appendix B to this
 2724 Part 40 CFR 75, incorporated by reference in Section 225.140.
 2725

2726 (Source: Amended at 33 Ill. Reg. _____, effective _____)
 2727

2728 **Section 225.265 Coal Analysis for Input Mercury Levels**
 2729

2730 a) The owner or operator of an EGU complying with this Subpart B by means of
 2731 Section 225.230(a)(1)(B), or using input mercury levels (I_i) and complying by
 2732 means of Section 225.230(b) or (d) or Section 225.232, electing to comply with
 2733 the emissions testing, monitoring, and recordkeeping requirements under Section
 2734 225.239, or demonstrating compliance under Section 225.233 or Sections 225.291
 2735 through 225.299 must fulfill the following requirements:
 2736

2737 1) Perform ~~daily~~ sampling of the coal combusted in the EGU for mercury
 2738 content. The owner or operator of such EGU must collect a minimum of
 2739 one 2-lb grab sample per day of operation from the belt feeders anywhere
 2740 between the crusher house or breaker building and the boiler. The sample
 2741 must be taken in a manner that provides a representative mercury content
 2742 for the coal burned on that day. EGUs complying by means of Section
 2743 225.233 or Sections 225.291 through 225.299 of this Subpart must
 2744 perform such coal sampling at least once per month; EGUs complying by
 2745 means of the emissions testing, monitoring, and recordkeeping
 2746 requirements under Section 225.239 must perform such coal sampling
 2747 according to the schedule provided in Section 225.239(e)(3) of this
 2748 Subpart; all other EGUs subject to this requirement must perform such
 2749 coal sampling on a daily basis.
 2750

2751 2) Analyze the grab coal sample for the following:
 2752

- 2753 A) Determine the heat content using ASTM D5865-04 or an
2754 equivalent method approved in writing by the Agency.
2755
2756 B) Determine the moisture content using ASTM D3173-03 or an
2757 equivalent method approved in writing by the Agency.
2758
2759 C) Measure the mercury content using ASTM D6414-01, ASTM
2760 D3684-01, or an equivalent method approved in writing by the
2761 Agency.
2762
2763 3) The owner or operator of multiple EGUs at the same source using the
2764 same crusher house or breaker building may take one sample per crusher
2765 house or breaker building, rather than one per EGU.
2766
2767 4) The owner or operator of an EGU must use the data analyzed pursuant to
2768 subsection (b) of this Section to determine the mercury content in terms of
2769 lbs/trillion Btu.
2770
2771 b) The owner or operator of an EGU that must conduct sampling and analysis of coal
2772 pursuant to subsection (a) of this Section must begin such activity by the
2773 following date:
2774
2775 1) If the EGU is in daily service, at least 30 days before the start of the month
2776 for which such activity will be required.
2777
2778 2) If the EGU is not in daily service, on the day that the EGU resumes
2779 operation.
2780

2781 (Source: Amended at 33 Ill. Reg. _____, effective _____)
2782

2783 **Section 225.270 Notifications**
2784

2785 The owner or operator of a source with one or more EGUs must submit written notice to the
2786 Agency according to the provisions in 40 CFR 75.61, incorporated by reference in Section
2787 225.140 (as a segment of 40 CFR 75), for each EGU or group of EGUs monitored at a common
2788 stack and each non-EGU monitored pursuant to Section 1.16(b)(2)(B) of Appendix B to this
2789 Part 40 CFR 75.82(b)(2)(ii), incorporated by reference in Section 225.140.
2790

2791 (Source: Amended at 33 Ill. Reg. _____, effective _____)
2792

2793 **Section 225.290 Recordkeeping and Reporting**
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- 2795 a) General Provisions.

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- 1) The owner or operator of an EGU and its designated representative must comply with all applicable recordkeeping and reporting requirements in this Section and with all applicable recordkeeping and reporting requirements of Section 1.18 to Appendix B to this Part40 CFR 75.84, incorporated by reference in Section 225.140.
 - 2) The owner or operator of an EGU must maintain records for each month identifying the emission standard in Section 225.230(a) or 225.237(a) of this Section with which it is complying or that is applicable for the EGU and the following records related to the emissions of mercury that the EGU is allowed to emit:
 - A) For an EGU for which the owner or operator is complying with this Subpart B by means of Section 225.230(a)(~~1~~)(B) or 225.237(a)(1)(B) or using input mercury levels to determine the allowable emissions of the EGU, records of the daily mercury content of coal used (lbs/trillion Btu) and the daily and monthly input mercury (lbs), which must be kept in the file pursuant to Section 1.18(a) of Appendix B to this Part40 CFR 75.84(a).
 - B) For an EGU for which the owner or operator of an EGU complying with this Subpart B by means of Section 225.230(a)(1)(A) or 225.237(a)(1)(A) or using electrical output to determine the allowable emissions of the EGU, records of the daily and monthly gross electrical output (GWh), which must be kept in the file required pursuant to Section 1.18(a) of Appendix B to this Part40 CFR 75.84(a).
 - 3) The owner or operator of an EGU must maintain records of the following data for each EGU:
 - A) Monthly emissions of mercury from the EGU.
 - B) For an EGU for which the owner or operator is complying by means of Section 225.230(b) or (d) of this Subpart B, records of the monthly allowable emissions of mercury from the EGU.
 - 4) The owner or operator of an EGU that is participating in an Averaging Demonstration pursuant to Section 225.232 of this Subpart B must maintain records identifying all sources and EGUs covered by the Demonstration for each month and, within 60 days after the end of each calendar month, calculate and record the actual and allowable mercury

- 2839 emissions of the EGU for the month and the applicable 12-month rolling
2840 period.
2841
- 2842 5) The owner or operator of an EGU must maintain the following records
2843 related to quality assurance activities conducted for emissions monitoring
2844 systems:
2845
- 2846 A) The results of quarterly assessments conducted pursuant to
2847 Section 2.2 of Exhibit B to Appendix B to this Part~~appendix~~
2848 ~~B of 40 CFR 75, incorporated by reference in Section 225.140;~~ and
2849
- 2850 B) Daily/weekly system integrity checks pursuant to Section 2.6 of Exhibit B to Appendix B to this Part~~appendix B of 40 CFR~~
2851 ~~75, incorporated by reference in Section 225.140.~~
2852
2853
- 2854 6) The owner or operator of an EGU must maintain an electronic copy of all
2855 electronic submittals to the USEPA pursuant to Section 1.18(f) to
2856 Appendix B to this Part~~40 CFR 75.84(f), incorporated by reference in~~
2857 ~~Section 225.140.~~
2858
- 2859 7) The owner or operator of an EGU must retain all records required by this
2860 Section at the source unless otherwise provided in the CAAPP permit
2861 issued for the source and must make a copy of any record available to the
2862 Agency upon request.
2863
- 2864 b) Quarterly Reports. The owner or operator of a source with one or more EGUs
2865 must submit quarterly reports to the Agency as follows:
2866
- 2867 1) These reports must include the following information for operation of the
2868 EGUs during the quarter:
2869
- 2870 A) The total operating hours of each EGU and the mercury CEMS, as
2871 also reported in accordance with Appendix B to this Part~~40 CFR~~
2872 ~~75, incorporated by reference in Section 225.140.~~
2873
- 2874 B) A discussion of any significant changes in the measures used to
2875 control emissions of mercury from the EGUs or the coal supply to
2876 the EGUs, including changes in the source of coal.
2877
- 2878 C) Summary information on the performance of the mercury CEMS.
2879 When the mercury CEMS was not inoperative, repaired, or
2880 adjusted, except for routine zero and span checks, this must be
2881 stated in the report.

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- D) If the CEMS downtime was more than 5.0 percent of the total operating time for the EGU: the date and time identifying each period during which the CEMS was inoperative, except for routine zero and span checks; the nature of CEMS repairs or adjustments and a summary of quality assurance data consistent with Appendix B to this Part 40-CFR-75, i.e., the dates and results of the Linearity Tests and any RATAs during the quarter; a listing of any days when a required daily calibration was not performed; and the date and duration of any periods when the CEMS was out-of-control as addressed by Section 225.260.
- E) Recertification testing that has been performed for any CEMS and the status of the results.
- 2) The owner or operator must submit each quarterly report to the Agency within 45 days following the end of the calendar quarter covered by the report.
- c) Compliance Certification. The owner or operator of a source with one or more EGUs must submit to the Agency a compliance certification in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the EGUs' emissions are correctly and fully monitored. The certification must state:
 - 1) That the monitoring data submitted were recorded in accordance with the applicable requirements of this Section, Sections 225.240 through 225.270 and Section 225.290 of this Subpart B, and Appendix B to this Part 40-CFR-75, including the quality assurance procedures and specifications; and
 - 2) For an EGU with add-on mercury emission controls, a flue gas desulfurization system, a selective catalytic reduction system, or a compact hybrid particulate collector system and for all hours where mercury data is missing that are substituted in accordance with 40-CFR 75.34(a)(1):
 - A) ~~That:~~
 - Ai) The mercury add-on emission controls, flue gas desulfurization system, selective catalytic reduction system, or compact hybrid particulate collector system was operating within the range of parameters listed in the quality assurance/quality control program

2925 pursuant to Exhibit B to Appendix B to this Part~~appendix B to 40~~
 2926 ~~CFR 75~~; or

2927
 2928 Bii) With regard to a flue gas desulfurization system or a selective
 2929 catalytic reduction system, quality-assured SO₂ emission data
 2930 recorded in accordance with Appendix B to this Part 40-CFR-75
 2931 document that the flue gas desulfurization system was operating
 2932 properly, or quality-assured NO_x emission data recorded in
 2933 accordance with Appendix B to this Part 40-CFR-75 document that
 2934 the selective catalytic reduction system was operating properly, as
 2935 applicable; and

2936
 2937 B) ~~The substitute data values do not systematically underestimate~~
 2938 ~~mercury emissions.~~

2939
 2940 d) Annual Certification of Compliance.

2941
 2942 1) The owner or operator of a source with one or more EGUs subject to this
 2943 Subpart B must submit to the Agency an Annual Certification of
 2944 Compliance with this Subpart B no later than May 1 of each year and must
 2945 address compliance for the previous calendar year. Such certification
 2946 must be submitted to the Agency, Air Compliance and Enforcement
 2947 Section, and the Air Regional Field Office.

2948
 2949 2) Annual Certifications of Compliance must indicate whether compliance
 2950 existed for each EGU for each month in the year covered by the
 2951 Certification and it must certify to that effect. In addition, for each EGU,
 2952 the owner or operator must provide the following appropriate data as set
 2953 forth in subsections (d)(2)(A) through (d)(2)(E) of this Section, together
 2954 with the data set forth in subsection (d)(2)(F) of this Section:

2955
 2956 A) If complying with this Subpart B by means of Section
 2957 225.230(a)(1)(A) or 225.237(a)(1)(A):

2958
 2959 i) Actual emissions rate, in lb/GWh, for each 12-month
 2960 rolling period ending in the year covered by the
 2961 Certification;

2962
 2963 ii) Actual emissions, in lbs, and gross electrical output, in
 2964 GWh, for each 12-month rolling period ending in the year
 2965 covered by the Certification; and
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- iii) Actual emissions, in lbs, and gross electrical output, in GWh, for each month in the year covered by the Certification and in the previous year.
 - B) If complying with this Subpart B by means of Section 225.230(a)(1)(B) or 225.237(a)(1)(B):
 - i) Actual control efficiency for emissions for each 12-month rolling period ending in the year covered by the Certification, expressed as a percent;
 - ii) Actual emissions, in lbs, and mercury content in the fuel fired in such EGU, in lbs, for each 12-month rolling period ending in the year covered by the Certification; and
 - iii) Actual emissions, in lbs, and mercury content in the fuel fired in such EGU, in lbs, for each month in the year covered by the Certification and in the previous year.
 - C) If complying with this Subpart B by means of Section 225.230(b):
 - i) Actual emissions and allowable emissions for each 12-month rolling period ending in the year covered by the Certification; and
 - ii) Actual emissions and allowable emissions, and which standard of compliance the owner or operator was utilizing for each month in the year covered by the Certification and in the previous year.
 - D) If complying with this Subpart B by means of Section 225.230(d):
 - i) Actual emissions and allowable emissions for all EGUs at the source for each 12-month rolling period ending in the year covered by the Certification; and
 - ii) Actual emissions and allowable emissions, and which standard of compliance the owner or operator was utilizing for each month in the year covered by the Certification and in the previous year.
 - E) If complying with this Subpart B by means of Section 225.232:

- 3010 i) Actual emissions and allowable emissions for all EGUs at
3011 the source in an Averaging Demonstration for each 12-
3012 month rolling period ending in the year covered by the
3013 Certification; and
3014
- 3015 ii) Actual emissions and allowable emissions, with the
3016 standard of compliance the owner or operator was utilizing
3017 for each EGU at the source in an Averaging Demonstration
3018 for each month for all EGUs at the source in an Averaging
3019 Demonstration in the year covered by the Certification and
3020 in the previous year.
3021
- 3022 F) Any deviations, data substitutions, or exceptions each month and
3023 discussion of the reasons for such deviations, data substitutions, or
3024 exceptions.
3025
- 3026 3) All Annual Certifications of Compliance required to be submitted must
3027 include the following certification by a responsible official:
3028
- 3029 I certify under penalty of law that this document and all attachments were
3030 prepared under my direction or supervision in accordance with a system
3031 designed to assure that qualified personnel properly gather and evaluate
3032 the information submitted. Based on my inquiry of the person or persons
3033 directly responsible for gathering the information, the information
3034 submitted is, to the best of my knowledge and belief, true, accurate, and
3035 complete. I am aware that there are significant penalties for submitting
3036 false information, including the possibility of fine and imprisonment for
3037 knowing violations.
3038
- 3039 4) The owner or operator of an EGU must submit its first Annual
3040 Certification of Compliance to address calendar year 2009 or the calendar
3041 year in which the EGU commences commercial operation, whichever is
3042 later. Notwithstanding subsection (d)(2) of this Section, in the Annual
3043 Certifications of Compliance that are required to be submitted by May 1,
3044 2010, and May 1, 2011, to address calendar years 2009 and 2010,
3045 respectively, the owner or operator is not required to provide 12-month
3046 rolling data for any period that ends before June 30, 2010.
3047
- 3048 e) Deviation Reports. For each EGU, the owner or operator must promptly notify
3049 the Agency of deviations from requirements of this Subpart B. At a minimum,
3050 these notifications must include a description of such deviations within 30 days
3051 after discovery of the deviations, and a discussion of the possible cause of such
3052 deviations, any corrective actions, and any preventative measures taken.

3053
 3054 f) Quality Assurance RATA Reports. The owner or operator of an EGU must
 3055 submit to the Agency, Air Compliance and Enforcement Section, the quality
 3056 assurance RATA report for each EGU or group of EGUs monitored at a common
 3057 stack and each non-EGU pursuant to Section 1.16(b)(2)(B) of Appendix B to this
 3058 Part 40 CFR 75.82(b)(2)(ii), incorporated by reference in Section 225.140, within
 3059 45 days after completing a quality assurance RATA.

3060
 3061 (Source: Amended at 33 Ill. Reg. _____, effective _____)
 3062

3063 **Section 225.291 Combined Pollutant Standard: Purpose**
 3064

3065 The purpose of Sections 225.291 through 225.299 (hereinafter referred to as the Combined
 3066 Pollutant Standard ("CPS")) is to allow an alternate means of compliance with the emissions
 3067 standards for mercury in Section 225.230(a) for specified EGUs through permanent shut-down,
 3068 installation of ACI, and the application of pollution control technology for NO_x, PM, and SO₂
 3069 emissions that also reduce mercury emissions as a co-benefit and to establish permanent
 3070 emissions standards for those specified EGUs. Unless otherwise provided for in the CPS,
 3071 owners and operators of those specified EGUs are not excused from compliance with other
 3072 applicable requirements of Subparts B, C, D, and E.

3073
 3074 (Source: Added at 33 Ill. Reg. _____, effective _____)
 3075

3076 **Section 225.292 Applicability of the Combined Pollutant Standard**
 3077

3078 a) As an alternative to compliance with the emissions standards of Section
 3079 225.230(a), the owner or operator of specified EGUs in the CPS located at Fisk,
 3080 Crawford, Joliet, Powerton, Waukegan, and Will County power plants may elect
 3081 for all of those EGUs as a group to demonstrate compliance pursuant to the CPS,
 3082 which establishes control requirements and emissions standards for NO_x, PM,
 3083 SO₂, and mercury. For this purpose, ownership of a specified EGU is determined
 3084 based on direct ownership, by holding a majority interest in a company that owns
 3085 the EGU or EGUs, or by the common ownership of the company that owns the
 3086 EGU, whether through a parent-subsidary relationship, as a sister corporation, or
 3087 as an affiliated corporation with the same parent corporation, provided that the
 3088 owner or operator has the right or authority to submit a CAAPP application on
 3089 behalf of the EGU.

3090
 3091 b) A specified EGU is a coal-fired EGU listed in Appendix A, irrespective of any
 3092 subsequent changes in ownership of the EGU or power plant, the operator, unit
 3093 designation, or name of unit.
 3094

- 3095 c) The owner or operator of each of the specified EGUs electing to demonstrate
3096 compliance with Section 225.230(a) pursuant to the CPS must submit an
3097 application for a CAAPP permit modification to the Agency, as provided for in
3098 Section 225.220, that includes the information specified in Section 225.293 that
3099 clearly states the owner's or operator's election to demonstrate compliance with
3100 Section 225.230(a) pursuant to the CPS.
3101
3102 d) If an owner or operator of one or more specified EGUs elects to demonstrate
3103 compliance with Section 225.230(a) pursuant to the CPS, then all specified EGUs
3104 owned or operated in Illinois by the owner or operator as of December 31, 2006,
3105 as defined in subsection (a) of this Section, are thereafter subject to the standards
3106 and control requirements of the CPS. Such EGUs are referred to as a Combined
3107 Pollutant Standard (CPS) group.
3108
3109 e) If an EGU is subject to the requirements of this Section, then the requirements
3110 apply to all owners and operators of the EGU, and to the CAIR designated
3111 representative for the EGU.
3112

3113 (Source: Added at 33 Ill. Reg. _____, effective _____)
3114

3115 **Section 225.293 Combined Pollutant Standard: Notice of Intent**
3116

3117 The owner or operator of one or more specified EGUs that intends to comply with Section
3118 225.230(a) by means of the CPS must notify the Agency of its intention on or before December
3119 31, 2007. The following information must accompany the notification:
3120

- 3121 a) The identification of each EGU that will be complying with Section 225.230(a)
3122 pursuant to the CPS, with evidence that the owner or operator has identified all
3123 specified EGUs that it owned or operated in Illinois as of December 31, 2006, and
3124 which commenced commercial operation on or before December 31, 2004;
3125
3126 b) If an EGU identified in subsection (a) of this Section is also owned or operated by
3127 a person different than the owner or operator submitting the notice of intent, a
3128 demonstration that the submitter has the right to commit the EGU or authorization
3129 from the responsible official for the EGU submitting the application; and
3130
3131 c) A summary of the current control devices installed and operating on each EGU
3132 and identification of the additional control devices that will likely be needed for
3133 each EGU to comply with emission control requirements of the CPS.
3134

3135 (Source: Added at 33 Ill. Reg., _____ effective _____)
3136

Section 225.294 Combined Pollutant Standard: Control Technology Requirements and Emissions Standards for Mercury

- a) Control Technology Requirements for Mercury.
 - 1) For each EGU in a CPS group other than an EGU that is addressed by subsection (b) of this Section, the owner or operator of the EGU must install, if not already installed, and properly operate and maintain, by the dates set forth in subsection (a)(2) of this Section, ACI equipment complying with subsections (g), (h), (i), (j), and (k) of this Section, as applicable.
 - 2) By the following dates, for the EGUs listed in subsections (a)(2)(A) and (B), which include hot and cold side ESPs, the owner or operator must install, if not already installed, and begin operating ACI equipment or the Agency must be given written notice that the EGU will be shut down on or before the following dates:
 - A) Fisk 19, Crawford 7, Crawford 8, Waukegan 7, and Waukegan 8 on or before July 1, 2008; and
 - B) Powerton 5, Powerton 6, Will County 3, Will County 4, Joliet 6, Joliet 7, and Joliet 8 on or before July 1, 2009.
- b) Notwithstanding subsection (a) of this Section, the following EGUs are not required to install ACI equipment because they will be permanently shut down, as addressed by Section 225.297, by the date specified:
 - 1) EGUs that are required to permanently shut down:
 - A) On or before December 31, 2007, Waukegan 6; and
 - B) On or before December 31, 2010, Will County 1 and Will County 2.
 - 2) Any other specified EGU that is permanently shut down by December 31, 2010.
- c) Beginning on January 1, 2015, and continuing thereafter, and measured on a rolling 12-month basis (the initial period is January 1, 2015, through December 31, 2015, and, then, for every 12-month period thereafter), each specified EGU, except Will County 3, shall achieve one of the following emissions standards:

- 3180 1) An emissions standard of 0.0080 lbs mercury/GWh gross electrical output;
3181 or
3182
3183 2) A minimum 90 percent reduction of input mercury.
3184
3185 d) Beginning on January 1, 2016, and continuing thereafter, Will County 3 shall
3186 achieve the mercury emissions standards of subsection (c) of this Section
3187 measured on a rolling 12-month basis (the initial period is January 1, 2016,
3188 through December 31, 2016, and, then, for every 12-month period thereafter).
3189
3190 e) Compliance with Emission Standards
3191
3192 1) At any time prior to the dates required for compliance in subsections (c)
3193 and (d) of this Section, the owner or operator of a specified EGU, upon
3194 notice to the Agency, may elect to comply with the emissions standards of
3195 subsection (c) of this Section measured on either:
3196
3197 A) a rolling 12-month basis, or;
3198
3199 B) semi-annual calendar basis pursuant to the emissions testing
3200 requirements in Section 225.239(c), (d), (e), (f)(1) and (2), (h)(2),
3201 and (i)(3) and (4) of this Subpart until June 30, 2012.
3202
3203 2) Once an EGU is subject to the mercury emissions standards of subsection
3204 (c) of this Section, it shall not be subject to the requirements of
3205 subsections (g), (h), (i), (j) and (k) of this Section.
3206
3207 f) Compliance with the mercury emissions standards or reduction requirement of
3208 this Section must be calculated in accordance with Section 225.230(a) or (b).
3209
3210 g) For each EGU for which injection of halogenated activated carbon is required by
3211 subsection (a)(1) of this Section, the owner or operator of the EGU must inject
3212 halogenated activated carbon in an optimum manner, which, except as provided in
3213 subsection (h) of this Section, is defined as all of the following:
3214
3215 1) The use of an injection system for effective absorption of mercury,
3216 considering the configuration of the EGU and its ductwork;
3217
3218 2) The injection of halogenated activated carbon manufactured by Alstom,
3219 Norit, or Sorbent Technologies, or Calgon Carbon's FLUEPAC MC Plus,
3220 or the injection of any other halogenated activated carbon or sorbent that
3221 the owner or operator of the EGU has demonstrated to have similar or
3222 better effectiveness for control of mercury emissions; and

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- 3) The injection of sorbent at the following minimum rates, as applicable:
 - A) For an EGU firing subbituminous coal, 5.0 lbs per million actual cubic feet or, for any cyclone-fired EGU that will install a scrubber and baghouse by December 31, 2012, and which already meets an emission rate of 0.020 lb mercury/GWh gross electrical output or at least 75 percent reduction of input mercury, 2.5 lbs per million actual cubic feet;
 - B) For an EGU firing bituminous coal, 10.0 lbs per million actual cubic feet or, for any cyclone-fired EGU that will install a scrubber and baghouse by December 31, 2012, and which already meets an emission rate of 0.020 lb mercury/GWh gross electrical output or at least 75 percent reduction of input mercury, 5.0 lbs per million actual cubic feet;
 - C) For an EGU firing a blend of subbituminous and bituminous coal, a rate that is the weighted average of the rates specified in subsections (g)(3)(A) and (B), based on the blend of coal being fired; or
 - D) A rate or rates set lower by the Agency, in writing, than the rate specified in any of subsection (g)(3)(A), (B), or (C) of this Section on a unit-specific basis, provided that the owner or operator of the EGU has demonstrated that such rate or rates are needed so that carbon injection will not increase particulate matter emissions or opacity so as to threaten noncompliance with applicable requirements for particulate matter or opacity.
- 4) For purposes of subsection (g)(3) of this Section, the flue gas flow rate must be determined for the point sorbent injection; provided that this flow rate may be assumed to be identical to the stack flow rate if the gas temperatures at the point of injection and the stack are normally within 100°F, or the flue gas flow rate may otherwise be calculated from the stack flow rate, corrected for the difference in gas temperatures.
- h) The owner or operator of an EGU that seeks to operate an EGU with an activated carbon injection rate or rates that are set on a unit-specific basis pursuant to subsection (g)(3)(D) of this Section must submit an application to the Agency proposing such rate or rates, and must meet the requirements of subsections (h)(1) and (h)(2) of this Section, subject to the limitations of subsections (h)(3) and (h)(4) of this Section:

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- 1) The application must be submitted as an application for a new or revised federally enforceable operation permit for the EGU, and it must include a summary of relevant mercury emissions data for the EGU, the unit-specific injection rate or rates that are proposed, and detailed information to support the proposed injection rate or rates; and
 - 2) This application must be submitted no later than the date that activated carbon must first be injected. For example, the owner or operator of an EGU that must inject activated carbon pursuant to subsection (a)(1) of this Section must apply for unit-specific injection rate or rates by July 1, 2008. Thereafter, the owner or operator may supplement its application; and
 - 3) Any decision of the Agency denying a permit or granting a permit with conditions that set a lower injection rate or rates may be appealed to the Board pursuant to Section 39 of the Act; and
 - 4) The owner or operator of an EGU may operate at the injection rate or rates proposed in its application until a final decision is made on the application including a final decision on any appeal to the Board.
- i) During any evaluation of the effectiveness of a listed sorbent, alternative sorbent, or other technique to control mercury emissions, the owner or operator of an EGU need not comply with the requirements of subsection (g) of this Section for any system needed to carry out the evaluation, as further provided as follows:
- 1) The owner or operator of the EGU must conduct the evaluation in accordance with a formal evaluation program submitted to the Agency at least 30 days prior to commencement of the evaluation;
 - 2) The duration and scope of the evaluation may not exceed the duration and scope reasonably needed to complete the desired evaluation of the alternative control techniques, as initially addressed by the owner or operator in a support document submitted with the evaluation program; and
 - 3) The owner or operator of the EGU must submit a report to the Agency no later than 30 days after the conclusion of the evaluation that describes the evaluation conducted and which provides the results of the evaluation; and
 - 4) If the evaluation of alternative control techniques shows less effective control of mercury emissions from the EGU than was achieved with the principal control techniques, the owner or operator of the EGU must

3309 resume use of the principal control techniques. If the evaluation of the
 3310 alternative control technique shows comparable effectiveness to the
 3311 principal control technique, the owner or operator of the EGU may either
 3312 continue to use the alternative control technique in a manner that is at least
 3313 as effective as the principal control technique or it may resume use of the
 3314 principal control technique. If the evaluation of the alternative control
 3315 technique shows more effective control of mercury emissions than the
 3316 control technique, the owner or operator of the EGU must continue to use
 3317 the alternative control technique in a manner that is more effective than
 3318 the principal control technique, so long as it continues to be subject to this
 3319 Section.

3320

3321 j) In addition to complying with the applicable recordkeeping and monitoring
 3322 requirements in Sections 225.240 through 225.290, the owner or operator of an
 3323 EGU that elects to comply with Section 225.230(a) by means of the CPS must
 3324 also comply with the following additional requirements:

3325

3326 1) For the first 36 months that injection of sorbent is required, it must
 3327 maintain records of the usage of sorbent, the exhaust gas flow rate from
 3328 the EGU, and the sorbent feed rate, in pounds per million actual cubic feet
 3329 of exhaust gas at the injection point, on a weekly average;

3330

3331 2) After the first 36 months that injection of sorbent is required, it must
 3332 monitor activated sorbent feed rate to the EGU, flue gas temperature at the
 3333 point of sorbent injection, and exhaust gas flow rate from the EGU,
 3334 automatically recording this data and the sorbent carbon feed rate, in
 3335 pounds per million actual cubic feet of exhaust gas at the injection point,
 3336 on an hourly average; and

3337

3338 3) If a blend of bituminous and subbituminous coal is fired in the EGU, it
 3339 must keep records of the amount of each type of coal burned and the
 3340 required injection rate for injection of activated carbon on a weekly basis.

3341

3342 k) In addition to complying with the applicable reporting requirements in Sections
 3343 225.240 through 225.290, the owner or operator of an EGU that elects to comply
 3344 with Section 225.230(a) by means of the CPS must also submit quarterly reports
 3345 for the recordkeeping and monitoring conducted pursuant to subsection (j) of this
 3346 Section.

3347

3348 l) As an alternative to the CEMS monitoring, recordkeeping, and reporting
 3349 requirements in Sections 225.240 through 225.290, the owner or operator of an
 3350 EGU may elect to comply with the emissions testing, monitoring, recordkeeping,

3351 and reporting requirements in Section 225.239(c), (d), (e), (f)(1) and (2), (h)(2),
3352 (i)(3) and (4), and (j)(1).

3353
3354 (Source: Added at 33 Ill. Reg. _____, effective _____)
3355

3356 **Section 225.295 Combined-Pollutant Standard: Emissions Standards for NO_x and**
3357 **SO₂ Treatment of Mercury Allowances**
3358

3359 ~~Any mercury allowances allocated to the Agency by the USEPA must be treated as follows:~~

- 3360
- 3361 a) ~~No such allowances may be allocated to any owner or operator of an EGU or~~
3362 ~~other sources of mercury emissions into the atmosphere or discharges into the~~
3363 ~~waters of the State.~~
 - 3364
 - 3365 b) ~~The Agency must hold all allowances allocated by the USEPA to the State. At~~
3366 ~~the end of each calendar year, the Agency must instruct the USEPA to retire~~
3367 ~~permanently all such allowances.~~
 - 3368
 - 3369 a) Emissions Standards for NO_x and Reporting Requirements.
3370
 - 3371 1) Beginning with calendar year 2012 and continuing in each calendar year
3372 thereafter, the CPS group, which includes all specified EGUs that have not
3373 been permanently shut down by December 31 before the applicable
3374 calendar year, must comply with a CPS group average annual NO_x
3375 emissions rate of no more than 0.11 lbs/mmBtu.
 - 3376
 - 3377 2) Beginning with ozone season control period 2012 and continuing in each
3378 ozone season control period (May 1 through September 30) thereafter, the
3379 CPS group, which includes all specified EGUs that have not been
3380 permanently shut down by December 31 before the applicable ozone
3381 season, must comply with a CPS group average ozone season NO_x
3382 emissions rate of no more than 0.11 lbs/mmBtu.
 - 3383
 - 3384 3) The owner or operator of the specified EGUs in the CPS group must file,
3385 not later than one year after startup of any selective SNCR on such EGU, a
3386 report with the Agency describing the NO_x emissions reductions that the
3387 SNCR has been able to achieve.
 - 3388
 - 3389 b) Emissions Standards for SO₂. Beginning in calendar year 2013 and continuing in
3390 each calendar year thereafter, the CPS group must comply with the applicable
3391 CPS group average annual SO₂ emissions rate listed as follows:
3392

3393 year

lbs/mmBtu

3394		
3395	<u>2013</u>	<u>0.44</u>
3396	<u>2014</u>	<u>0.41</u>
3397	<u>2015</u>	<u>0.28</u>
3398	<u>2016</u>	<u>0.195</u>
3399	<u>2017</u>	<u>0.15</u>
3400	<u>2018</u>	<u>0.13</u>
3401	<u>2019</u>	<u>0.11</u>
3402		

c) Compliance with the NO_x and SO₂ emissions standards must be demonstrated in accordance with Sections 225.310, 225.410, and 225.510. The owner or operator of the specified EGUs must complete the demonstration of compliance pursuant to Section 225.298(c) before March 1 of the following year for annual standards and before November 30 of the particular year for ozone season control periods (May 1 through September 30) standards, by which date a compliance report must be submitted to the Agency.

d) The CPS group average annual SO₂ emission rate, annual NO_x emission rate and ozone season NO_x emission rates shall be determined as follows:

$$ER_{avg} = \frac{\sum_{i=1}^n (SO_{2i} \text{ or } NO_{xi} \text{ tons})}{\sum_{i=1}^n (HI_i)}$$

Where:

- ER_{avg} = average annual or ozone season emission rate in lbs/mmBtu of all EGUs in the CPS group.
- HI_i = heat input for the annual or ozone control period of each EGU, in mmBtu.
- SO_{2i} = actual annual SO₂ tons of each EGU in the CPS group.
- NO_{xi} = actual annual or ozone season NO_x tons of each EGU in the CPS group.
- n = number of EGUs that are in the CPS group
- i = each EGU in the CPS group.

(Source: Amended at 33 Ill. Reg. _____, effective _____)

Section 225.296 Combined Pollutant Standard: Control Technology Requirements for NO_x, SO₂, and PM Emissions

a) Control Technology Requirements for NO_x and SO₂.

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- 1) On or before December 31, 2013, the owner or operator must either permanently shut down or install and have operational FGD equipment on Waukegan 7;
 - 2) On or before December 31, 2014, the owner or operator must either permanently shut down or install and have operational FGD equipment on Waukegan 8;
 - 3) On or before December 31, 2015, the owner or operator must either permanently shut down or install and have operational FGD equipment on Fisk 19;
 - 4) If Crawford 7 will be operated after December 31, 2018, and not permanently shut down by this date, the owner or operator must:
 - A) On or before December 31, 2015, install and have operational SNCR or equipment capable of delivering essentially equivalent NO_x reductions on Crawford 7; and
 - B) On or before December 31, 2018, install and have operational FGD equipment on Crawford 7;
 - 5) If Crawford 8 will be operated after December 31, 2017 and not permanently shut down by this date, the owner or operator must:
 - A) On or before December 31, 2015, install and have operational SNCR or equipment capable of delivering essentially equivalent NO_x emissions reductions on Crawford 8; and
 - B) On or before December 31, 2017, install and have operational FGD equipment on Crawford 8.
- b) Other Control Technology Requirements for SO₂. Owners or operators of specified EGUs must either permanently shut down or install FGD equipment on each specified EGU (except Joliet 5), on or before December 31, 2018, unless an earlier date is specified in subsection (a) of this Section.
- c) Control Technology Requirements for PM. The owner or operator of the two specified EGUs listed in this subsection that are equipped with a hot-side ESP must replace the hot-side ESP with a cold-side ESP, install an appropriately designed fabric filter, or permanently shut down the EGU by the dates specified. Hot-side ESP means an ESP on a coal-fired boiler that is installed before the boiler's air-preheater where the operating temperature is typically at least 550°F,

3471 as distinguished from a cold-side ESP that is installed after the air pre-heater
 3472 where the operating temperature is typically no more than 350°F.

3473
 3474 1) Waukegan 7 on or before December 31, 2013; and

3475
 3476 2) Will County 3 on or before December 31, 2015.

3477
 3478 d) Beginning on December 31, 2008, and annually thereafter up to and including
 3479 December 31, 2015, the owner or operator of the Fisk power plant must submit in
 3480 writing to the Agency a report on any technology or equipment designed to affect
 3481 air quality that has been considered or explored for the Fisk power plant in the
 3482 preceding 12 months. This report will not obligate the owner or operator to install
 3483 any equipment described in the report.

3484
 3485 e) Notwithstanding 35 Ill. Adm. Code 201.146(hhh), until an EGU has complied
 3486 with the applicable requirements of subsections 225.296(a), (b), and (c), the
 3487 owner or operator of the EGU must obtain a construction permit for any new or
 3488 modified air pollution control equipment that it proposes to construct for control
 3489 of emissions of mercury, NO_x, PM, or SO₂.

3490
 3491 (Source: Added at 33 Ill. Reg. _____, effective _____)

3492
 3493 **Section 225.297 Combined Pollutant Standard: Permanent Shut-Downs**

3494
 3495 a) The owner or operator of the following EGUs must permanently shut down the
 3496 EGU by the dates specified:

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 3498 1) Waukegan 6 on or before December 31, 2007; and

3499
 3500 2) Will County 1 and Will County 2 on or before December 31, 2010.

3501
 3502 b) No later than 8 months before the date that a specified EGU will be permanently
 3503 shut down, the owner or operator must submit a report to the Agency that includes
 3504 a description of the actions that have already been taken to allow the shutdown of
 3505 the EGU and a description of the future actions that must be accomplished to
 3506 complete the shutdown of the EGU, with the anticipated schedule for those
 3507 actions and the anticipated date of permanent shutdown of the unit.

3508
 3509 c) No later than six months before a specified EGU will be permanently shut down,
 3510 the owner or operator shall apply for revisions to the operating permits for the
 3511 EGU to include provisions that terminate the authorization to operate the unit on
 3512 that date.

3513

3514 d) If after applying for or obtaining a construction permit to install required control
 3515 equipment, the owner or operator decides to permanently shut-down a Specified
 3516 EGU rather than install the required control technology, the owner or operator
 3517 must immediately notify the Agency in writing and thereafter submit the
 3518 information required by subsections (b) and (c) of this Section.

3519
 3520 e) Failure to permanently shut down a specified EGU by the required date shall be
 3521 considered separate violations of the applicable emissions standards and control
 3522 technology requirements of the CPS for NO_x, PM, SO₂, and mercury.

3523
 3524 (Source: Added at 33 Ill. Reg. _____, effective _____)

3525
 3526 **Section 225.298 Combined Pollutant Standard: Requirements for NO_x and SO₂**
 3527 **Allowances**

3528
 3529 a) The following requirements apply to the owner, the operator, and the designated
 3530 representative with respect to SO₂ and NO_x allowances:

3531
 3532 1) The owner, operator, and designated representative of specified EGUs in a
 3533 CPS group is permitted to sell, trade, or transfer SO₂ and NO_x emissions
 3534 allowances of any vintage owned, allocated to, or earned by the specified
 3535 EGUs (the "CPS allowances") to its affiliated Homer City, Pennsylvania,
 3536 generating station for as long as the Homer City Station needs the CPS
 3537 allowances for compliance.

3538
 3539 2) When and if the Homer City Station no longer requires all of the CPS
 3540 allowances, the owner, operator, or designated representative of specified
 3541 EGUs in a CPS group may sell any and all remaining CPS allowances,
 3542 without restriction, to any person or entity located anywhere, except that
 3543 the owner or operator may not directly sell, trade, or transfer CPS
 3544 allowances to a unit located in Ohio, Indiana, Illinois, Wisconsin,
 3545 Michigan, Kentucky, Missouri, Iowa, Minnesota, or Texas.

3546
 3547 3) In no event shall this subsection (a) require or be interpreted to require any
 3548 restriction whatsoever on the sale, trade, or exchange of the CPS
 3549 allowances by persons or entities who have acquired the CPS allowances
 3550 from the owner, operator, or designated representative of specified EGUs
 3551 in a CPS group.

3552
 3553 b) The owner, operator, and designated representative of EGUs in a specified CPS
 3554 group is prohibited from purchasing or using SO₂ and NO_x allowances for the
 3555 purposes of meeting the SO₂ and NO_x emissions standards set forth in Section
 3556 225.295.

3557
 3558 c) Before March 1, 2010, and continuing each year thereafter, the designated
 3559 representative of the EGUs in a CPS group must submit a report to the Agency
 3560 that demonstrates compliance with the requirements of this Section for the
 3561 previous calendar year and ozone season control period (May 1 through
 3562 September 30), and includes identification of any NO_x or SO₂ allowances that
 3563 have been used for compliance with any NO_x or SO₂ trading programs, and any
 3564 NO_x or SO₂ allowances that were sold, gifted, used, exchanged, or traded. A final
 3565 report must be submitted to the Agency by August 31 of each year, providing
 3566 either verification that the actions described in the initial report have taken place,
 3567 or, if such actions have not taken place, an explanation of the changes that have
 3568 occurred and the reasons for such changes.

3569 (Source: Added at 33 Ill. Reg. _____, effective _____)

3570
 3571
 3572 **Section 225.299 Combined Pollutant Standard: Clean Air Act Requirements**

3573
 3574 The SO₂ emissions rates set forth in the CPS shall be deemed to be best available retrofit
 3575 technology ("BART") under the Visibility Protection provisions of the CAA (42 USC 7491),
 3576 reasonably available control technology ("RACT") and reasonably available control measures
 3577 ("RACM") for achieving fine particulate matter ("PM_{2.5}") requirements under NAAQS in effect
 3578 on August 31, 2007, as required by the CAA (42 USC 7502). The Agency may use the SO₂ and
 3579 NO_x emissions reductions required under the CPS in developing attainment demonstrations and
 3580 demonstrating reasonable further progress for PM_{2.5} and 8 hour ozone standards, as required
 3581 under the CAA. Furthermore, in developing rules, regulations, or State Implementation Plans
 3582 designed to comply with PM_{2.5} and 8 hour ozone NAAQS, the Agency, taking into account all
 3583 emission reduction efforts and other appropriate factors, will use best efforts to seek SO₂ and
 3584 NO_x emissions rates from other EGUs that are equal to or less than the rates applicable to the
 3585 CPS group and will seek SO₂ and NO_x reductions from other sources before seeking additional
 3586 emissions reductions from any EGU in the CPS group.

3587
 3588 (Source: Added at 33 Ill. Reg. _____, effective _____)

3589
 3590 SUBPART F: COMBINED POLLUTANT STANDARDS

3591
 3592 **Section 225.600 Purpose (Repealed)**

3593
 3594 ~~The purpose of this Subpart F is to allow an alternate means of compliance with the emissions~~
 3595 ~~standards for mercury in Section 225.230(a) for specified EGUs through permanent shut down,~~
 3596 ~~installation of ACI, and the application of pollution control technology for NO_x, PM, and SO₂~~
 3597 ~~emissions that also reduce mercury emissions as a co-benefit and to establish permanent~~
 3598 ~~emissions standards for those specified EGUs. Unless otherwise provided for in this Subpart F,~~

3599 owners and operators of those specified EGUs are not excused from compliance with other
 3600 applicable requirements of Subparts B, C, D, and E.

3601

(Source: Repealed at 33 Ill. Reg. _____, effective _____)

3603

3604 **Section 225.605 Applicability (Repealed)**

3605

3606

a) As an alternative to compliance with the emissions standards of Section
 225.230(a), the owner or operator of specified EGUs in this Subpart F located at
 Fisk, Crawford, Joliet, Powerton, Waukegan, and Will County power plants may
 elect for all of those EGUs as a group to demonstrate compliance pursuant to this
 Subpart F, which establishes control requirements and emissions standards for
 NO_x, PM, SO₂, and mercury. For this purpose, ownership of a specified EGU is
 determined based on direct ownership, by holding a majority interest in a
 company that owns the EGU or EGUs, or by the common ownership of the
 company that owns the EGU, whether through a parent subsidiary relationship, as
 a sister corporation, or as an affiliated corporation with the same parent
 corporation, provided that the owner or operator has the right or authority to
 submit a CAAPP application on behalf of the EGU.

3618

3619

b) A specified EGU is a coal-fired EGU listed in Appendix A, irrespective of any
 subsequent changes in ownership of the EGU or power plant, the operator, unit
 designation, or name of unit.

3622

3623

e) The owner or operator of each of the specified EGUs electing to demonstrate
 compliance with Section 225.230(a) pursuant to this Subpart must submit an
 application for a CAAPP permit modification to the Agency, as provided for in
 Section 225.220, that includes the information specified in Section 225.610 that
 clearly states the owner's or operator's election to demonstrate compliance with
 Section 225.230(a) pursuant to this Subpart F.

3629

3630

d) If an owner or operator of one or more specified EGUs elects to demonstrate
 compliance with Section 225.230(a) pursuant to this Subpart F, then all specified
 EGUs owned or operated in Illinois by the owner or operator as of December 31,
 2006, as defined in subsection (a) of this Section, are thereafter subject to the
 standards and control requirements of this Subpart F. Such EGUs are referred to
 as a Combined Pollutant Standard (CPS) group.

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3637

e) If an EGU is subject to the requirements of this Section, then the requirements
 apply to all owners and operators of the EGU, and to the CAIR designated
 representative for the EGU.

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3641

(Source: Repealed at 33 Ill. Reg. _____, effective _____)

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Section 225.610 Notice of Intent (Repealed)

The owner or operator of one or more specified EGUs that intends to comply with Section 225.230(a) by means of this Subpart F must notify the Agency of its intention on or before December 31, 2007. The following information must accompany the notification:

- a) The identification of each EGU that will be complying with Section 225.230(a) pursuant to this Subpart F, with evidence that the owner or operator has identified all specified EGUs that it owned or operated in Illinois as of December 31, 2006, and which commenced commercial operation on or before December 31, 2004;
- b) If an EGU identified in subsection (a) of this Section is also owned or operated by a person different than the owner or operator submitting the notice of intent, a demonstration that the submitter has the right to commit the EGU or authorization from the responsible official for the EGU submitting the application; and
- e) A summary of the current control devices installed and operating on each EGU and identification of the additional control devices that will likely be needed for each EGU to comply with emission control requirements of this Subpart F.

(Source: Repealed at 33 Ill. Reg. _____, effective _____)

Section 225.615 Control Technology Requirements and Emissions Standards for Mercury (Repealed)

- a) Control Technology Requirements for Mercury.
 - 1) For each EGU in a CPS group other than an EGU that is addressed by subsection (b) of this Section, the owner or operator of the EGU must install, if not already installed, and properly operate and maintain, by the dates set forth in subsection (a)(2) of this Section, ACI equipment complying with subsections (g), (h), (i), (j), and (k) of this Section, as applicable.
 - 2) By the following dates, for the EGUs listed in subsections (a)(2)(A) and (B), which include hot and cold side ESPs, the owner or operator must install, if not already installed, and begin operating ACI equipment or the Agency must be given written notice that the EGU will be shut down on or before the following dates:
 - A) Fisk 19, Crawford 7, Crawford 8, Waukegan 7, and Waukegan 8 on or before July 1, 2008; and

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- B) ~~Powerton 5, Powerton 6, Will County 3, Will County 4, Joliet 6, Joliet 7, and Joliet 8 on or before July 1, 2009.~~

- b) ~~Notwithstanding subsection (a) of this Section, the following EGUs are not required to install ACI equipment because they will be permanently shut down, as addressed by Section 225.630, by the date specified:~~
 - 1) ~~EGUs that are required to permanently shut down:~~
 - A) ~~On or before December 31, 2007, Waukegan 6; and~~
 - B) ~~On or before December 31, 2010, Will County 1 and Will County 2.~~
 - 2) ~~Any other specified EGU that is permanently shut down by December 31, 2010.~~

- e) ~~Beginning on January 1, 2015 and continuing thereafter, and measured on a rolling 12-month basis (the initial period is January 1, 2015, through December 31, 2015, and, then, for every 12-month period thereafter), each specified EGU, except Will County 3, shall achieve one of the following emissions standards:~~
 - 1) ~~An emissions standard of 0.0080 lbs mercury/GWh gross electrical output; or~~
 - 2) ~~A minimum 90 percent reduction of input mercury.~~

- d) ~~Beginning on January 1, 2016, and continuing thereafter, Will County 3 shall achieve the mercury emissions standards of subsection (c) of this Section measured on a rolling 12-month basis (the initial period is January 1, 2016 through December 31, 2016, and, then, for every 12-month period thereafter).~~

- e) ~~At any time prior to the dates required for compliance in subsections (c) and (d) of this Section, the owner or operator of a specified EGU, upon notice to the Agency, may elect to comply with the emissions standards of subsection (c) of this Section measured on a rolling 12-month basis for one or more EGUs. Once an EGU is subject to the mercury emissions standards of subsection (c) of this Section, it shall not be subject to the requirements of subsections (g), (h), (i), (j) and (k) of this Section.~~

- f) ~~Compliance with the mercury emissions standards or reduction requirement of this Section must be calculated in accordance with Section 225.230(a) or (b).~~

- 3728
 3729 g) For each EGU for which injection of halogenated activated carbon is required by
 3730 subsection (a)(1) of this Section, the owner or operator of the EGU must inject
 3731 halogenated activated carbon in an optimum manner, which, except as provided in
 3732 subsection (h) of this Section, is defined as all of the following:
 3733
 3734 1) The use of an injection system for effective absorption of mercury,
 3735 considering the configuration of the EGU and its ductwork;
 3736
 3737 2) The injection of halogenated activated carbon manufactured by Alstom,
 3738 Norit, or Sorbent Technologies, or the injection of any other halogenated
 3739 activated carbon or sorbent that the owner or operator of the EGU has
 3740 demonstrated to have similar or better effectiveness for control of mercury
 3741 emissions; and
 3742
 3743 3) The injection of sorbent at the following minimum rates, as applicable:
 3744
 3745 A) For an EGU firing subbituminous coal, 5.0 lbs per million actual
 3746 cubic feet or, for any cyclone fired EGU that will install a scrubber
 3747 and baghouse by December 31, 2012, and which already meets an
 3748 emission rate of 0.020 lb mercury/GWh gross electrical output or
 3749 at least 75 percent reduction of input mercury, 2.5 lbs per million
 3750 actual cubic feet;
 3751
 3752 B) For an EGU firing bituminous coal, 10.0 lbs per million actual
 3753 cubic feet or, for any cyclone fired EGU that will install a scrubber
 3754 and baghouse by December 31, 2012, and which already meets an
 3755 emission rate of 0.020 lb mercury/GWh gross electrical output or
 3756 at least 75 percent reduction of input mercury, 5.0 lbs per million
 3757 actual cubic feet;
 3758
 3759 C) For an EGU firing a blend of subbituminous and bituminous coal,
 3760 a rate that is the weighted average of the rates specified in
 3761 subsections (g)(3)(A) and (B), based on the blend of coal being
 3762 fired; or
 3763
 3764 D) A rate or rates set lower by the Agency, in writing, than the rate
 3765 specified in any of subsection (g)(3)(A), (B), or (C) of this Section
 3766 on a unit-specific basis, provided that the owner or operator of the
 3767 EGU has demonstrated that such rate or rates are needed so that
 3768 carbon injection will not increase particulate matter emissions or
 3769 opacity so as to threaten noncompliance with applicable
 3770 requirements for particulate matter or opacity.

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- 4) For purposes of subsection (g)(3) of this Section, the flue gas flow rate must be determined for the point sorbent injection; provided that this flow rate may be assumed to be identical to the stack flow rate if the gas temperatures at the point of injection and the stack are normally within 100°F, or the flue gas flow rate may otherwise be calculated from the stack flow rate, corrected for the difference in gas temperatures.
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- h) The owner or operator of an EGU that seeks to operate an EGU with an activated carbon injection rate or rates that are set on a unit-specific basis pursuant to subsection (g)(3)(D) of this Section must submit an application to the Agency proposing such rate or rates, and must meet the requirements of subsections (h)(1) and (h)(2) of this Section, subject to the limitations of subsections (h)(3) and (h)(4) of this Section:
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- 1) The application must be submitted as an application for a new or revised federally enforceable operation permit for the EGU, and it must include a summary of relevant mercury emissions data for the EGU, the unit-specific injection rate or rates that are proposed, and detailed information to support the proposed injection rate or rates; and
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- 2) This application must be submitted no later than the date that activated carbon must first be injected. For example, the owner or operator of an EGU that must inject activated carbon pursuant to subsection (a)(1) of this Section must apply for unit-specific injection rate or rates by July 1, 2008. Thereafter, the owner or operator may supplement its application; and
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- 3) Any decision of the Agency denying a permit or granting a permit with conditions that set a lower injection rate or rates may be appealed to the Board pursuant to Section 39 of the Act; and
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- 4) The owner or operator of an EGU may operate at the injection rate or rates proposed in its application until a final decision is made on the application including a final decision on any appeal to the Board.
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 3810
- i) During any evaluation of the effectiveness of a listed sorbent, alternative sorbent, or other technique to control mercury emissions, the owner or operator of an EGU need not comply with the requirements of subsection (g) of this Section for any system needed to carry out the evaluation, as further provided as follows:
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- 1) The owner or operator of the EGU must conduct the evaluation in accordance with a formal evaluation program submitted to the Agency at least 30 days prior to commencement of the evaluation; and

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- 2) The duration and scope of the evaluation may not exceed the duration and scope reasonably needed to complete the desired evaluation of the alternative control techniques, as initially addressed by the owner or operator in a support document submitted with the evaluation program; and
 - 3) The owner or operator of the EGU must submit a report to the Agency no later than 30 days after the conclusion of the evaluation that describes the evaluation conducted and which provides the results of the evaluation; and
 - 4) If the evaluation of alternative control techniques shows less effective control of mercury emissions from the EGU than was achieved with the principal control techniques, the owner or operator of the EGU must resume use of the principal control techniques. If the evaluation of the alternative control technique shows comparable effectiveness to the principal control technique, the owner or operator of the EGU may either continue to use the alternative control technique in a manner that is at least as effective as the principal control technique or it may resume use of the principal control technique. If the evaluation of the alternative control technique shows more effective control of mercury emissions than the control technique, the owner or operator of the EGU must continue to use the alternative control technique in a manner that is more effective than the principal control technique, so long as it continues to be subject to this Section.
- j) In addition to complying with the applicable recordkeeping and monitoring requirements in Sections 225.240 through 225.290, the owner or operator of an EGU that elects to comply with Section 225.230(a) by means of this Subpart F must also comply with the following additional requirements:
- 1) For the first 36 months that injection of sorbent is required, it must maintain records of the usage of sorbent, the exhaust gas flow rate from the EGU, and the sorbent feed rate, in pounds per million actual cubic feet of exhaust gas at the injection point, on a weekly average;
 - 2) After the first 36 months that injection of sorbent is required, it must monitor activated sorbent feed rate to the EGU, flue gas temperature at the point of sorbent injection, and exhaust gas flow rate from the EGU, automatically recording this data and the sorbent carbon feed rate, in pounds per million actual cubic feet of exhaust gas at the injection point, on an hourly average; and

3857 3) If a blend of bituminous and subbituminous coal is fired in the EGU, it
 3858 must keep records of the amount of each type of coal burned and the
 3859 required injection rate for injection of activated carbon on a weekly basis.
 3860

3861 k) In addition to complying with the applicable reporting requirements in Sections
 3862 225.240 through 225.290, the owner or operator of an EGU that elects to comply
 3863 with Section 225.230(a) by means of this Subpart F must also submit quarterly
 3864 reports for the recordkeeping and monitoring conducted pursuant to subsection (j)
 3865 of this Section.
 3866

3867 (Source: Repealed at 33 Ill. Reg. _____, effective _____)
 3868

3869 **Section 225.620 Emissions Standards for NO_x and SO₂ (Repealed)**
 3870

3871 a) Emissions Standards for NO_x and Reporting Requirements.
 3872

3873 1) Beginning with calendar year 2012 and continuing in each calendar year
 3874 thereafter, the CPS group, which includes all specified EGUs that have not
 3875 been permanently shut down by December 31 before the applicable
 3876 calendar year, must comply with a CPS group average annual NO_x
 3877 emissions rate of no more than 0.11 lbs/mmBtu.
 3878

3879 2) Beginning with ozone season control period 2012 and continuing in each
 3880 ozone season control period (May 1 through September 30) thereafter, the
 3881 CPS group, which includes all specified EGUs that have not been
 3882 permanently shut down by December 31 before the applicable ozone
 3883 season, must comply with a CPS group average ozone season NO_x
 3884 emissions rate of no more than 0.11 lbs/mmBtu.
 3885

3886 3) The owner or operator of the specified EGUs in the CPS group must file,
 3887 not later than one year after startup of any selective SNCR on such EGU, a
 3888 report with the Agency describing the NO_x emissions reductions that the
 3889 SNCR has been able to achieve.
 3890

3891 b) Emissions Standards for SO₂. Beginning in calendar year 2013 and continuing in
 3892 each calendar year thereafter, the CPS group must comply with the applicable
 3893 CPS group average annual SO₂ emissions rate listed as follows:
 3894

year	lbs/mmBtu
2013	0.44
2014	0.41
2015	0.28
2016	0.195

2017	0.15
2018	0.13
2019	0.11

- 3895
 3896 e) Compliance with the NO_x and SO₂ emissions standards must be demonstrated in
 3897 accordance with Sections 225.310, 225.410, and 225.510. The owner or operator
 3898 of the specified EGUs must complete the demonstration of compliance pursuant
 3899 to Section 225.635(c) before March 1 of the following year for annual standards
 3900 and before November 30 of the particular year for ozone season control periods
 3901 (May 1 through September 30) standards, by which date a compliance report must
 3902 be submitted to the Agency.
 3903
 3904 d) The CPS group average annual SO₂ emission rate, annual NO_x emission rate and
 3905 ozone season NO_x emission rates shall be determined as follows:
 3906

$$ER_{avg} = \frac{\sum_{i=1}^n (SO_{2i} \text{ or } NO_{xi} \text{ tons})}{\sum_{i=1}^n (HI_i)}$$

3907
 3908 Where:

- 3909 ER_{avg} = average annual or ozone season emission rate in lbs/mmbtu of all
 3910 EGUs in the CPS group.
 HI_i = heat input for the annual or ozone control period of each EGU, in
 mmbtu.
 SO_{2i} = actual annual SO₂ tons of each EGU in the CPS group.
 NO_{xi} = actual annual or ozone season NO_x tons of each EGU in the CPS
 group.
 n = number of EGUs that are in the CPS group
 i = each EGU in the CPS group

3911 (Source: Repealed at 33 Ill. Reg. _____, effective _____)
 3912
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3914 **Section 225.625 Control Technology Requirements for NO_x, SO₂, and PM Emissions**
 3915 **(Repealed)**
 3916

- 3917 a) Control Technology Requirements for NO_x and SO₂:
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 3919 1) On or before December 31, 2013, the owner or operator must either
 3920 permanently shut down or install and have operational FGD equipment on
 3921 Waukegan 7;
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- 2) ~~On or before December 31, 2014, the owner or operator must either permanently shut down or install and have operational FGD equipment on Waukegan 8;~~
 - 3) ~~On or before December 31, 2015, the owner or operator must either permanently shut down or install and have operational FGD equipment on Fisk 19;~~
 - 4) ~~If Crawford 7 will be operated after December 31, 2018, and not permanently shut down by this date, the owner or operator must:~~
 - A) ~~On or before December 31, 2015, install and have operational SNCR or equipment capable of delivering essentially equivalent NO_x reductions on Crawford 7; and~~
 - B) ~~On or before December 31, 2018, install and have operational FGD equipment on Crawford 7;~~
 - 5) ~~If Crawford 8 will be operated after December 31, 2017 and not permanently shut down by this date, the owner or operator must:~~
 - A) ~~On or before December 31, 2015, install and have operational SNCR or equipment capable of delivering essentially equivalent NO_x emissions reductions on Crawford 8; and~~
 - B) ~~On or before December 31, 2017, install and have operational FGD equipment on Crawford 8.~~
 - b) ~~Other Control Technology Requirements for SO₂. Owners or operators of specified EGUs must either permanently shut down or install FGD equipment on each specified EGU (except Joliet 5), on or before December 31, 2018, unless an earlier date is specified in subsection (a) of this Section.~~
 - e) ~~Control Technology Requirements for PM. The owner or operator of the two specified EGUs listed in this subsection that are equipped with a hot-side ESP must replace the hot-side ESP with a cold-side ESP, install an appropriately designed fabric filter, or permanently shut down the EGU by the dates specified. Hot-side ESP means an ESP on a coal-fired boiler that is installed before the boiler's air preheater where the operating temperature is typically at least 550° F, as distinguished from a cold-side ESP that is installed after the air pre-heater where the operating temperature is typically no more than 350° F.~~
 - 1) ~~Waukegan 7 on or before December 31, 2013; and~~

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- 2) ~~Will County 3 on or before December 31, 2015.~~
- d) ~~Beginning on December 31, 2008, and annually thereafter up to and including December 31, 2015, the owner or operator of the Fisk power plant must submit in writing to the Agency a report on any technology or equipment designed to affect air quality that has been considered or explored for the Fisk power plant in the preceding 12 months. This report will not obligate the owner or operator to install any equipment described in the report.~~
- e) ~~Notwithstanding 35 Ill. Adm. Code 201.146(hhh), until an EGU has complied with the applicable requirements of subsections 225.625(a), (b), and (c), the owner or operator of the EGU must obtain a construction permit for any new or modified air pollution control equipment that it proposes to construct for control of emissions of mercury, NO_x, PM, or SO₂.~~

(Source: Repealed at 33 Ill. Reg. _____, effective _____)

Section 225.630 Permanent Shut-Downs (Repealed)

- a) ~~The owner or operator of the following EGUs must permanently shut down the EGU by the dates specified:~~
 - 1) ~~Waukegan 6 on or before December 31, 2007; and~~
 - 2) ~~Will County 1 and Will County 2 on or before December 31, 2010.~~
- b) ~~No later than 8 months before the date that a specified EGU will be permanently shut down, the owner or operator must submit a report to the Agency that includes a description of the actions that have already been taken to allow the shutdown of the EGU and a description of the future actions that must be accomplished to complete the shutdown of the EGU, with the anticipated schedule for those actions and the anticipated date of permanent shutdown of the unit.~~
- c) ~~No later than six months before a specified EGU will be permanently shut down, the owner or operator shall apply for revisions to the operating permits for the EGU to include provisions that terminate the authorization to operate the unit on that date.~~
- d) ~~If after applying for or obtaining a construction permit to install required control equipment, the owner or operator decides to permanently shut down a Specified EGU rather than install the required control technology, the owner or operator~~

4008 must immediately notify the Agency in writing and thereafter submit the
 4009 information required by subsections (b) and (c) of this Section.

- 4010
 4011 e) Failure to permanently shut down a specified EGU by the required date shall be
 4012 considered separate violations of the applicable emissions standards and control
 4013 technology requirements of this Subpart F for NO_x, PM, SO₂, and mercury.

4014
 4015 (Source: Repealed at 33 Ill. Reg. _____, effective _____)

4016
 4017 **Section 225.635 Requirements for CAIR SO₂, CAIR NO_x, and CAIR NO_x Ozone Season**
 4018 **Allowances (Repealed)**

- 4019
 4020 a) The following requirements apply to the owner, the operator and the designated
 4021 representative with respect to CAIR SO₂, CAIR NO_x, and CAIR NO_x Ozone
 4022 Season allowances:

4023
 4024 1) The owner, operator, and CAIR designated representative of specified
 4025 EGUs in a CPS group is permitted to sell, trade, or transfer SO₂ and NO_x
 4026 emissions allowances of any vintage owned, allocated to, or earned by the
 4027 specified EGUs (the "CPS allowances") to its affiliated Homer City,
 4028 Pennsylvania generating station for as long as the Homer City Station
 4029 needs the CPS allowances for compliance.

4030
 4031 2) When and if the Homer City Station no longer requires all of the CPS
 4032 allowances, the owner, operator, or CAIR designated representative of
 4033 specified EGUs in CPS group may sell any and all remaining CPS
 4034 allowances, without restriction, to any person or entity located anywhere,
 4035 except that the owner or operator may not directly sell, trade, or transfer
 4036 CPS allowances to a CAIR NO_x or CAIR SO₂ unit located in Ohio,
 4037 Indiana, Illinois, Wisconsin, Michigan, Kentucky, Missouri, Iowa,
 4038 Minnesota, or Texas.

4039
 4040 3) In no event shall this subsection (a) require or be interpreted to require any
 4041 restriction whatsoever on the sale, trade, or exchange of the CPS
 4042 allowances by persons or entities who have acquired the CPS allowances
 4043 from the owner, operator, or CAIR designated representative of specified
 4044 EGUs in a CPS group.

- 4045
 4046 b) The owner, operator, and CAIR designated representative of EGUs in a specified
 4047 CPS group is prohibited from purchasing or using CAIR SO₂, CAIR NO_x, and
 4048 CAIR NO_x Ozone Season allowances for the purposes of meeting the SO₂ and
 4049 NO_x emissions standards set forth in Section 225.620.
 4050

4051 e) Before March 1, 2010, and continuing each year thereafter, the CAIR designated
 4052 representative of the EGUs in a CPS group must submit a report to the Agency
 4053 that demonstrates compliance with the requirements of this Section for the
 4054 previous calendar year and ozone season control period (May 1 through
 4055 September 30), and includes identification of any CAIR allowances that have
 4056 been used for compliance with the CAIR Trading Programs as set forth in
 4057 Subparts C, D, and E, and any CAIR allowances that were sold, gifted, used,
 4058 exchanged, or traded. A final report must be submitted to the Agency by August
 4059 31 of each year, providing either verification that the actions described in the
 4060 initial report have taken place, or, if such actions have not taken place, an
 4061 explanation of the changes that have occurred and the reasons for such changes.
 4062

4063 (Source: Repealed at 33 Ill. Reg. _____, effective _____)
 4064

4065 **Section 225.640 Clean Air Act Requirements (Repealed)**
 4066

4067 The SO₂ emissions rates set forth in this Subpart F shall be deemed to be best available retrofit
 4068 technology ("BART") under the Visibility Protection provisions of the CAA (42 USC 7491),
 4069 reasonably available control technology ("RACT") and reasonably available control measures
 4070 ("RACM") for achieving fine particulate matter ("PM_{2.5}") requirements under NAAQS in effect
 4071 on August 31, 2007, as required by the CAA (42 USC 7502). The Agency may use the SO₂ and
 4072 NO_x emissions reductions required under this Subpart F in developing attainment demonstrations
 4073 and demonstrating reasonable further progress for PM_{2.5} and 8 hour ozone standards, as required
 4074 under the CAA. Furthermore, in developing rules, regulations, or State Implementation Plans
 4075 designed to comply with PM_{2.5} and 8 hour ozone NAAQS, the Agency, taking into account all
 4076 emission reduction efforts and other appropriate factors, will use best efforts to seek SO₂ and
 4077 NO_x emissions rates from other EGUs that are equal to or less than the rates applicable to the
 4078 CPS group and will seek SO₂ and NO_x reductions from other sources before seeking additional
 4079 emissions reductions from any EGU in the CPS group.
 4080

4081 (Source: Repealed at 33 Ill. Reg. _____, effective _____)

4082 **Section 225.APPENDIX A Specified EGUs for Purposes of the CPSSubpart F (Midwest**
 4083 **Generation's Coal-Fired Boilers as of July 1, 2006)**
 4084

Plant	Permit Number	Boiler	Permit designation	CPSSubpart F Designation
Crawford	031600AIN	7	Unit 7 Boiler BLR1	Crawford 7
		8	Unit 8 Boiler BLR2	Crawford 8
Fisk	031600AMI	19	Unit 19 Boiler BLR19	Fisk 19
Joliet	197809AAO	71	Unit 7 Boiler BLR71	Joliet 7
		72	Unit 7 Boiler BLR72	Joliet 7
		81	Unit 8 Boiler BLR81	Joliet 8
		82	Unit 8 Boiler BLR82	Joliet 8
		5	Unit 6 Boiler BLR5	Joliet 6
Powerton	179801AAA	51	Unit 5 Boiler BLR51	Powerton 5
		52	Unit 5 Boiler BLR52	Powerton 5
		61	Unit 6 Boiler BLR61	Powerton 6
		62	Unit 6 Boiler BLR62	Powerton 6
Waukegan	097190AAC	17	Unit 6 Boiler BLR17	Waukegan 6
		7	Unit 7 Boiler BLR7	Waukegan 7
		8	Unit 8 Boiler BLR8	Waukegan 8
Will County	197810AAK	1	Unit 1 Boiler BLR1	Will County 1
		2	Unit 2 Boiler BLR2	Will County 2
		3	Unit 3 Boiler BLR3	Will County 3
		4	Unit 4 Boiler BLR4	Will County 4

4085

4086 (Source: Amended at 33 Ill. Reg. _____, effective _____)

4087 **Section 225.APPENDIX B Continuous Emission Monitoring Systems for Mercury**

4088
4089 **Section 1.1 Applicability**

4090
4091 The provisions of this Appendix apply to sources subject to 35 Ill. Adm. Code 225 mercury (Hg)
4092 mass emission reduction program.

4093
4094 **Section 1.2 General Operating Requirements**

4095
4096 a) Primary Equipment Performance Requirements. The owner or operator must
4097 ensure that each continuous mercury emission monitoring system required by this
4098 Appendix meets the equipment, installation and performance specifications in
4099 Exhibit A to this Appendix and is maintained according to the quality assurance
4100 and quality control procedures in Exhibit B to this Appendix.

4101
4102 b) Heat Input Rate Measurement Requirement. The owner or operator must
4103 determine and record the heat input rate, in units of mmBtu/hr, to each affected
4104 unit for every hour or part of an hour any fuel is combusted following the
4105 procedures in Exhibit C to this Appendix.

4106
4107 c) Primary Equipment Hourly Operating Requirements. The owner or operator must
4108 ensure that all continuous mercury emission monitoring systems required by this
4109 Appendix are in operation and monitoring unit emissions at all times that the
4110 affected unit combusts any fuel except during periods of calibration, quality
4111 assurance, or preventive maintenance, performed pursuant to Section 1.5 of this
4112 Appendix and Exhibit B to this Appendix, periods of repair, periods of backups of
4113 data from the data acquisition and handling system, or recertification performed
4114 pursuant to Section 1.4 of this Appendix.

4115
4116 1) The owner or operator must ensure that each continuous emission
4117 monitoring system is capable of completing a minimum of one cycle of
4118 operation (sampling, analyzing and data recording) for each successive 15-
4119 minute interval. The owner or operator must reduce all volumetric flow,
4120 CO₂ concentration, O₂ concentration and mercury concentration data
4121 collected by the monitors to hourly averages. Hourly averages must be
4122 computed using at least one data point in each 15 minute quadrant of an
4123 hour, where the unit combusted fuel during that quadrant of an hour.
4124 Notwithstanding this requirement, an hourly average may be computed
4125 from at least two data points separated by a minimum of 15 minutes
4126 (where the unit operates for more than one quadrant of an hour) if data are
4127 unavailable as a result of the performance of calibration, quality assurance,
4128 or preventive maintenance activities pursuant to Section 1.5 of this
4129 Appendix and Exhibit B to this Appendix, or backups of data from the

4130 data acquisition and handling system, or recertification, pursuant to
 4131 Section 1.4 of this Appendix. The owner or operator must use all valid
 4132 measurements or data points collected during an hour to calculate the
 4133 hourly averages. All data points collected during an hour must be, to the
 4134 extent practicable, evenly spaced over the hour.

4135
 4136 2) Failure of a CO₂ or O₂ emissions concentration monitor, mercury
 4137 concentration monitor, flow monitor or a moisture monitor to acquire the
 4138 minimum number of data points for calculation of an hourly average in
 4139 subsection (c)(1) of this Section must result in the failure to obtain a valid
 4140 hour of data and the loss of such component data for the entire hour. For a
 4141 moisture monitoring system consisting of one or more oxygen analyzers
 4142 capable of measuring O₂ on a wet-basis and a dry-basis, an hourly average
 4143 percent moisture value is valid only if the minimum number of data points
 4144 is acquired for both the wet-and dry-basis measurements.

4145
 4146 d) Optional Backup Monitor Requirements. If the owner or operator chooses to use
 4147 two or more continuous mercury emission monitoring systems, each of which is
 4148 capable of monitoring the same stack or duct at a specific affected unit, or group
 4149 of units using a common stack, then the owner or operator must designate one
 4150 monitoring system as the primary monitoring system, and must record this
 4151 information in the monitoring plan, as provided for in Section 1.10 of this
 4152 Appendix. The owner or operator must designate the other monitoring systems as
 4153 backup monitoring systems in the monitoring plan. The backup monitoring
 4154 systems must be designated as redundant backup monitoring systems, non-
 4155 redundant backup monitoring systems, or reference method backup systems, as
 4156 described in Section 1.4(d) of this Appendix. When the certified primary
 4157 monitoring system is operating and not out-of-control as defined in Section 1.7 of
 4158 this Appendix, only data from the certified primary monitoring system must be
 4159 reported as valid, quality-assured data. Thus, data from the backup monitoring
 4160 system may be reported as valid, quality-assured data only when the backup is
 4161 operating and not out-of-control as defined in Section 1.7 of this Appendix (or in
 4162 the applicable reference method in appendix A of 40 CFR 60, incorporated by
 4163 reference in Section 225.140) and when the certified primary monitoring system
 4164 is not operating (or is operating but out-of-control). A particular monitor may be
 4165 designated both as a certified primary monitor for one unit and as a certified
 4166 redundant backup monitor for another unit.

4167
 4168 e) Minimum Measurement Capability Requirement. The owner or operator must
 4169 ensure that each continuous emission monitoring system is capable of accurately
 4170 measuring, recording and reporting data, and must not incur an exceedance of the
 4171 full scale range, except as provided in Section 2.1.2.3 of Exhibit A to this
 4172 Appendix.

4173
 4174 f) Minimum Recording and Recordkeeping Requirements. The owner or operator
 4175 must record and the designated representative must report the hourly, daily,
 4176 quarterly and annual information collected under the requirements as specified in
 4177 subpart G of 40 CFR 75, incorporated by reference in Section 225.140, and
 4178 Section 1.11 through 1.13 of this Appendix.
 4179

4180 **Section 1.3 Special Provisions for Measuring Mercury Mass Emissions Using the Excepted**
 4181 **Sorbent Trap Monitoring Methodology**
 4182

4183 For an affected coal-fired unit under 35 Ill. Adm. Code 225, if the owner or operator elects to use
 4184 sorbent trap monitoring systems (as defined in Section 225.130) to quantify mass emissions, the
 4185 guidelines in subsections (a) through (l) of this Section must be followed for this excepted
 4186 monitoring methodology:
 4187

- 4188 a) For each sorbent trap monitoring system (whether primary or redundant backup),
 4189 the use of paired sorbent traps, as described in Exhibit D to this Appendix, is
 4190 required;
 4191
 4192 b) Each sorbent trap must have a main section, a backup section and a third section
 4193 to allow spiking with a calibration gas of known mercury concentration, as
 4194 described in Exhibit D to this Appendix;
 4195
 4196 c) A certified flow monitoring system is required;
 4197
 4198 d) Correction for stack gas moisture content is required, and in some cases, a
 4199 certified O₂ or CO₂ monitoring system is required (see Section 1.15(a)(4));
 4200
 4201 e) Each sorbent trap monitoring system must be installed and operated in accordance
 4202 with Exhibit D to this Appendix. The automated data acquisition and handling
 4203 system must ensure that the sampling rate is proportional to the stack gas
 4204 volumetric flow rate.
 4205
 4206 f) At the beginning and end of each sample collection period, and at least once in
 4207 each unit operating hour during the collection period, the gas flow meter reading
 4208 must be recorded.
 4209
 4210 g) After each sample collection period, the mass of mercury adsorbed in each
 4211 sorbent trap (in all three sections) must be determined according to the applicable
 4212 procedures in Exhibit D to this Appendix.
 4213
 4214 h) The hourly mercury mass emissions for each collection period are determined
 4215 using the results of the analyses in conjunction with contemporaneous hourly data

4216 recorded by a certified stack flow monitor, corrected for the stack gas moisture
 4217 content. For each pair of sorbent traps analyzed, the average of the 2 mercury
 4218 concentrations must be used for reporting purposes under Section 1.18(f) of this
 4219 Appendix. Notwithstanding this requirement, if, due to circumstances beyond the
 4220 control of the owner or operator, one of the paired traps is accidentally lost,
 4221 damaged or broken and cannot be analyzed, the results of the analysis of the other
 4222 trap may be used for reporting purposes, provided that the other trap has met all of
 4223 the applicable quality-assurance requirements of this Part.
 4224

4225 i) All unit operating hours for which valid mercury concentration data are obtained
 4226 with the primary sorbent trap monitoring system (as verified using the quality
 4227 assurance procedures in Exhibit D to this Appendix) must be reported in the
 4228 electronic quarterly report under Section 1.18(f) of this Appendix. For hours in
 4229 which data from the primary monitoring system are invalid, the owner or operator
 4230 may, in accordance with Section 1.4(d) of this Appendix, report valid mercury
 4231 concentration data from: a certified redundant backup CEMS or sorbent trap
 4232 monitoring system; a certified non-redundant backup CEMS or sorbent trap
 4233 monitoring system; or an applicable reference method under Section 1.6 of this
 4234 Appendix.
 4235

4236 j) Initial certification requirements and additional quality-assurance requirements
 4237 for the sorbent trap monitoring systems are found in Section 1.4(c)(7), in Section
 4238 6.5.6 of Exhibit A to this Appendix, in Sections 1.3 and 2.3 of Exhibit B to this
 4239 Appendix, and in Exhibit D to this Appendix.
 4240

4241 k) During each RATA of a sorbent trap monitoring system, the type of sorbent
 4242 material used by the traps must be the same as for daily operation of the
 4243 monitoring system. A new pair of traps must be used for each RATA run.
 4244 However, the size of the traps used for the RATA may be smaller than the traps
 4245 used for daily operation of the system.
 4246

4247 l) Whenever the type of sorbent material used by the traps is changed, the owner or
 4248 operator must conduct a diagnostic RATA of the modified sorbent trap
 4249 monitoring system within 720 unit or stack operating hours after the date and hour
 4250 when the new sorbent material is first used. If the diagnostic RATA is passed,
 4251 data from the modified system may be reported as quality-assured, back to the
 4252 date and hour when the new sorbent material was first used. If the RATA is
 4253 failed, all data from the modified system must be invalidated, back to the date and
 4254 hour when the new sorbent material was first used, and data from the system must
 4255 remain invalid until a subsequent RATA is passed. If the required RATA is not
 4256 completed within 720 unit or stack operating hours, but is passed on the first
 4257 attempt, data from the modified system must be invalidated beginning with the
 4258 first operating hour after the 720 unit or stack operating hour window expires, and

4259 data from the system must remain invalid until the date and hour of completion of
 4260 the successful RATA.
 4261

4262 **Section 1.4 Initial Certification and Recertification Procedures**
 4263

- 4264 a) Initial Certification Approval Process. The owner or operator must ensure that
 4265 each continuous mercury emission monitoring system required by this Appendix
 4266 meets the initial certification requirements of this Section. In addition, whenever
 4267 the owner or operator installs a continuous mercury emission monitoring system
 4268 in order to meet the requirements of Section 1.3 of this Appendix and 40 CFR
 4269 sections 75.11 through 75.14 and 75.16 through 75.18, incorporated by reference
 4270 in Section 225.140, where no continuous emission monitoring system was
 4271 previously installed, initial certification is required.
 4272
- 4273 1) Notification of initial certification test dates. The owner or operator or
 4274 designated representative must submit a written notice of the dates of
 4275 initial certification testing at the unit as specified in 40 CFR 75.61(a)(1),
 4276 incorporated by reference in Section 225.140.
 4277
- 4278 2) Certification application. The owner or operator must apply for
 4279 certification of each continuous mercury emission monitoring system.
 4280 The owner or operator must submit the certification application in
 4281 accordance with 40 CFR 75.60, incorporated by reference in Section
 4282 225.140, and each complete certification application must include the
 4283 information specified in 40 CFR 75.63, incorporated by reference in
 4284 Section 225.140.
 4285
- 4286 3) Provisional approval of certification (or recertification) applications. Upon
 4287 the successful completion of the required certification (or recertification)
 4288 procedures of this Section, each continuous mercury emission monitoring
 4289 system must be deemed provisionally certified (or recertified) for use for a
 4290 period not to exceed 120 days following receipt by the Agency of the
 4291 complete certification (or recertification) application under subsection
 4292 (a)(4) of this Section. Data measured and recorded by a provisionally
 4293 certified (or recertified) continuous emission monitoring system, operated
 4294 in accordance with the requirements of Exhibit B to this Appendix, will be
 4295 considered valid quality-assured data (retroactive to the date and time of
 4296 provisional certification or recertification), provided that the Agency does
 4297 not invalidate the provisional certification (or recertification) by issuing a
 4298 notice of disapproval within 120 days of receipt by the Agency of the
 4299 complete certification (or recertification) application. Note that when the
 4300 conditional data validation procedures of subsection (b)(3) of this Section
 4301 are used for the initial certification (or recertification) of a continuous

4302 emissions monitoring system, the date and time of provisional certification
 4303 (or recertification) of the CEMS may be earlier than the date and time of
 4304 completion of the required certification (or recertification) tests.

4305
 4306 4) Certification (or recertification) application formal approval process. The
 4307 Agency will issue a notice of approval or disapproval of the certification
 4308 (or recertification) application to the owner or operator within 120 days
 4309 after receipt of the complete certification (or recertification) application. In
 4310 the event the Agency does not issue such a notice within 120 days after
 4311 receipt, each continuous emission monitoring system that meets the
 4312 performance requirements of this Part and is included in the certification
 4313 (or recertification) application will be deemed certified (or recertified) for
 4314 use under 35 Ill. Adm. Code 225.

4315
 4316 A) Approval notice. If the certification (or recertification) application
 4317 is complete and shows that each continuous emission monitoring
 4318 system meets the performance requirements of this Part, then the
 4319 Agency will issue a notice of approval of the certification (or
 4320 recertification) application within 120 days after receipt.

4321
 4322 B) Incomplete application notice. A certification (or recertification)
 4323 application will be considered complete when all of the applicable
 4324 information required to be submitted in 40 CFR 75.63,
 4325 incorporated by reference in Section 225.140, has been received by
 4326 the Agency. If the certification (or recertification) application is
 4327 not complete, then the Agency will issue a notice of
 4328 incompleteness that provides a reasonable timeframe for the
 4329 designated representative to submit the additional information
 4330 required to complete the certification (or recertification)
 4331 application. If the designated representative has not complied with
 4332 the notice of incompleteness by a specified due date, then the
 4333 Agency may issue a notice of disapproval specified under
 4334 subsection (a)(4)(C) of this Section. The 120-day review period
 4335 will not begin prior to receipt of a complete application.

4336
 4337 C) Disapproval notice. If the certification (or recertification)
 4338 application shows that any continuous emission monitoring system
 4339 does not meet the performance requirements of this Part, or if the
 4340 certification (or recertification) application is incomplete and the
 4341 requirement for disapproval under subsection (a)(4)(B) of this
 4342 Section has been met, the Agency must issue a written notice of
 4343 disapproval of the certification (or recertification) application
 4344 within 120 days after receipt. By issuing the notice of disapproval,

4345 the provisional certification (or recertification) is invalidated by the
 4346 Agency, and the data measured and recorded by each uncertified
 4347 continuous emission or opacity monitoring system must not be
 4348 considered valid quality-assured data as follows: from the hour of
 4349 the probationary calibration error test that began the initial
 4350 certification (or recertification) test period (if the conditional data
 4351 validation procedures of subsection (b)(3) of this Section were
 4352 used to retrospectively validate data); or from the date and time of
 4353 completion of the invalid certification or recertification tests (if the
 4354 conditional data validation procedures of subsection (b)(3) of this
 4355 Section were not used). The owner or operator must follow the
 4356 procedures for loss of initial certification in subsection (a)(5) of
 4357 this Section for each continuous emission or opacity monitoring
 4358 system that is disapproved for initial certification. For each
 4359 disapproved recertification, the owner or operator must follow the
 4360 procedures of subsection (b)(5) of this Section.

4361
 4362 5) Procedures for loss of certification. When the Agency issues a notice of
 4363 disapproval of a certification application or a notice of disapproval of
 4364 certification status (as specified in subsection (a)(4) of this Section), then:

4365
 4366 A) Until such time, date and hour as the continuous mercury emission
 4367 monitoring system can be adjusted, repaired or replaced and
 4368 certification tests successfully completed (or, if the conditional
 4369 data validation procedures in subsections (b)(3)(B) through (I) of
 4370 this Section are used, until a probationary calibration error test is
 4371 passed following corrective actions in accordance with subsection
 4372 (b)(3)(B) of this Section), the owner or operator must perform
 4373 emissions testing pursuant to Section 225.239.

4374
 4375 B) The designated representative must submit a notification of
 4376 certification retest dates as specified in Section 225.250(a)(3)(A)
 4377 and a new certification application according to the procedures in
 4378 Section 225.250(a)(3)(B); and

4379
 4380 C) The owner or operator must repeat all certification tests or other
 4381 requirements that were failed by the continuous mercury emission
 4382 monitoring system, as indicated in the Agency's notice of
 4383 disapproval, no later than 30 unit operating days after the date of
 4384 issuance of the notice of disapproval.

4385
 4386 b) Recertification Approval Process. Whenever the owner or operator makes a
 4387 replacement, modification or change in a certified continuous mercury emission

4388 monitoring system that may significantly affect the ability of the system to
 4389 accurately measure or record the gas volumetric flow rate, mercury concentration,
 4390 percent moisture, or to meet the requirements of Section 1.5 of this Appendix or
 4391 Exhibit B to this Appendix, the owner or operator must recertify the continuous
 4392 mercury emission monitoring system, according to the procedures in this
 4393 subsection. Examples of changes that require recertification include: replacement
 4394 of the analyzer; change in location or orientation of the sampling probe or site;
 4395 and complete replacement of an existing continuous mercury emission monitoring
 4396 system. The owner or operator must also recertify the continuous emission
 4397 monitoring systems for a unit that has recommenced commercial operation
 4398 following a period of long-term cold storage as defined in Section 225.130. Any
 4399 change to a flow monitor or gas monitoring system for which a RATA is not
 4400 necessary will not be considered a recertification event. In addition, changing the
 4401 polynomial coefficients or K factors of a flow monitor will require a 3-load
 4402 RATA, but is not considered to be a recertification event; however, records of the
 4403 polynomial coefficients or K factors currently in use must be maintained on-site
 4404 in a format suitable for inspection. Changing the coefficient or K factors of a
 4405 moisture monitoring system will require a RATA, but is not considered to be a
 4406 recertification event; however, records of the coefficient or K factors currently in
 4407 use by the moisture monitoring system must be maintained on-site in a format
 4408 suitable for inspection. In such cases, any other tests that are necessary to ensure
 4409 continued proper operation of the monitoring system (e.g., 3-load flow RATAs
 4410 following changes to flow monitor polynomial coefficients, linearity checks,
 4411 calibration error tests, DAHS verifications, etc.) must be performed as diagnostic
 4412 tests, rather than as recertification tests. The data validation procedures in
 4413 subsection (b)(3) of this Section must be applied to RATAs associated with
 4414 changes to flow or moisture monitor coefficients, and to linearity checks, 7-day
 4415 calibration error tests and cycle time tests when these are required as diagnostic
 4416 tests. When the data validation procedures of subsection (b)(3) of this Section are
 4417 applied in this manner, replace the word "recertification" with the word
 4418 "diagnostic".

- 4420 1) Tests required. For all recertification testing, the owner or operator must
 4421 complete all initial certification tests in subsection (c) of this Section that
 4422 are applicable to the monitoring system, except as otherwise approved by
 4423 the Agency. For diagnostic testing after changing the flow rate monitor
 4424 polynomial coefficients, the owner or operator must complete a 3-level
 4425 RATA. For diagnostic testing after changing the K factor or mathematical
 4426 algorithm of a moisture monitoring system, the owner or operator must
 4427 complete a RATA.
- 4428 2) Notification of recertification test dates. The owner, operator or designated
 4429 representative must submit notice of testing dates for recertification under
 4430

4431 this subsection as specified in 40 CFR 75.61(a)(1)(ii), incorporated by
 4432 reference in Section 225.140, unless all of the tests in subsection (c) of this
 4433 Section are required for recertification, in which case the owner or
 4434 operator must provide notice in accordance with the notice provisions for
 4435 initial certification testing in 40 CFR 75.61(a)(1)(i), incorporated by
 4436 reference in Section 225.140.

4437
 4438 3) Recertification test period requirements and data validation. The data
 4439 validation provisions in subsections (b)(3)(A) through (I) of this Section
 4440 will apply to all mercury CEMS recertifications and diagnostic testing.
 4441 The provisions in subsections (b)(3)(B) through (I) of this Section may
 4442 also be applied to initial certifications (see Sections 6.2(a), 6.3.1(a),
 4443 6.3.2(a), 6.4(a) and 6.5(f) of Exhibit A to this Appendix) and may be used
 4444 to supplement the linearity check and RATA data validation procedures in
 4445 Sections 2.2.3(b) and 2.3.2(b) of Exhibit B to this Appendix.

4446
 4447 A) The owner or operator must report emission data using a reference
 4448 method or another monitoring system that has been certified or
 4449 approved for use under this Part, in the period extending from the
 4450 hour of the replacement, modification or change made to a
 4451 monitoring system that triggers the need to perform recertification
 4452 testing, until either: the hour of successful completion of all of the
 4453 required recertification tests; or the hour in which a probationary
 4454 calibration error test (according to subsection (b)(3)(B) of this
 4455 Section) is performed and passed, following all necessary repairs,
 4456 adjustments or reprogramming of the monitoring system. The first
 4457 hour of quality-assured data for the recertified monitoring system
 4458 must either be the hour after all recertification tests have been
 4459 completed or, if conditional data validation is used, the first
 4460 quality-assured hour must be determined in accordance with
 4461 subsection (b)(3)(B) through (I) of this Section. Notwithstanding
 4462 these requirements, if the replacement, modification or change
 4463 requiring recertification of the CEMS is such that the historical
 4464 data stream is no longer representative (e.g., where the mercury
 4465 concentration and stack flow rate change significantly after
 4466 installation of a wet scrubber), the owner or operator must estimate
 4467 the mercury emissions over that time period and notify the Agency
 4468 within 15 days after the replacement, modification or change
 4469 requiring recertification of the CEMS.

4470
 4471 B) Once the modification or change to the CEMS has been completed
 4472 and all of the associated repairs, component replacements,
 4473 adjustments, linearization and reprogramming of the CEMS have

4474 been completed, a probationary calibration error test is required to
4475 establish the beginning point of the recertification test period. In
4476 this instance, the first successful calibration error test of the
4477 monitoring system following completion of all necessary repairs,
4478 component replacements, adjustments, linearization and
4479 reprogramming must be the probationary calibration error test. The
4480 probationary calibration error test must be passed before any of the
4481 required recertification tests are commenced.

4482
4483 C) Beginning with the hour of commencement of a recertification test
4484 period, emission data recorded by the mercury CEMS are
4485 considered to be conditionally valid, contingent upon the results of
4486 the subsequent recertification tests.

4487
4488 D) Each required recertification test must be completed no later than
4489 the following number of unit operating hours (or unit operating
4490 days) after the probationary calibration error test that initiates the
4491 test period:

4492
4493 i) For a linearity check and/or cycle time test, 168
4494 consecutive unit operating hours, as defined in 40 CFR
4495 72.2, incorporated by reference in Section 225.140, or, for
4496 CEMS installed on common stacks or bypass stacks, 168
4497 consecutive stack operating hours, as defined in 40 CFR
4498 72.2;

4499
4500 ii) For a RATA (whether normal-load or multiple-load), 720
4501 consecutive unit operating hours, as defined in 40 CFR
4502 72.2, incorporated by reference in Section 225.140, or, for
4503 CEMS installed on common stacks or bypass stacks, 720
4504 consecutive stack operating hours, as defined in 40 CFR
4505 72.2; and

4506
4507 iii) For a 7-day calibration error test, 21 consecutive unit
4508 operating days, as defined in 40 CFR 72.2, incorporated by
4509 reference in Section 225.140.

4510
4511 E) All recertification tests must be performed hands-off. No
4512 adjustments to the calibration of the mercury CEMS, other than the
4513 routine calibration adjustments following daily calibration error
4514 tests as described in Section 2.1.3 of Exhibit B to this Appendix,
4515 are permitted during the recertification test period. Routine daily
4516 calibration error tests must be performed throughout the

4517 recertification test period, in accordance with Section 2.1.1 of
 4518 Exhibit B to this Appendix. The additional calibration error test
 4519 requirements in Section 2.1.3 of Exhibit B to this Appendix, must
 4520 also apply during the recertification test period.

4521
 4522 F) If all of the required recertification tests and required daily
 4523 calibration error tests are successfully completed in succession
 4524 with no failures, and if each recertification test is completed within
 4525 the time period specified in subsection (b)(3)(D)(i), (ii) or (iii) of
 4526 this Section, then all of the conditionally valid emission data
 4527 recorded by the mercury CEMS will be considered quality assured,
 4528 from the hour of commencement of the recertification test period
 4529 until the hour of completion of the required tests.

4530
 4531 G) If a required recertification test is failed or aborted due to a
 4532 problem with the mercury CEMS, or if a daily calibration error test
 4533 is failed during a recertification test period, data validation must be
 4534 done as follows:

4535
 4536 i) If any required recertification test is failed, it must be
 4537 repeated. If any recertification test other than a 7-day
 4538 calibration error test is failed or aborted due to a problem
 4539 with the mercury CEMS, the original recertification test
 4540 period is ended, and a new recertification test period must
 4541 be commenced with a probationary calibration error test.
 4542 The tests that are required in the new recertification test
 4543 period will include any tests that were required for the
 4544 initial recertification event that were not successfully
 4545 completed and any recertification or diagnostic tests that
 4546 are required as a result of changes made to the monitoring
 4547 system to correct the problems that caused the failure of the
 4548 recertification test. For a 2- or 3-load flow RATA, if the
 4549 relative accuracy test is passed at one or more load levels,
 4550 but is failed at a subsequent load level, provided that the
 4551 problem that caused the RATA failure is corrected without
 4552 re-linearizing the instrument, the length of the new
 4553 recertification test period must be equal to the number of
 4554 unit operating hours remaining in the original
 4555 recertification test period, as of the hour of failure of the
 4556 RATA. However, if re-linearization of the flow monitor is
 4557 required after a flow RATA is failed at a particular load
 4558 level, then a subsequent 3-load RATA is required, and the
 4559 new recertification test period must be 720 consecutive unit

- 4560 (or stack) operating hours. The new recertification test
 4561 sequence must not be commenced until all necessary
 4562 maintenance activities, adjustments, linearization and
 4563 reprogramming of the CEMS have been completed;
 4564
- 4565 ii) If a linearity check, RATA or cycle time test is failed or
 4566 aborted due to a problem with the mercury CEMS, all
 4567 conditionally valid emission data recorded by the CEMS
 4568 are invalidated, from the hour of commencement of the
 4569 recertification test period to the hour in which the test is
 4570 failed or aborted, except for the case in which a multiple-
 4571 load flow RATA is passed at one or more load levels, failed
 4572 at a subsequent load level, and the problem that caused the
 4573 RATA failure is corrected without re-linearizing the
 4574 instrument. In that case, data invalidation will be
 4575 prospective, from the hour of failure of the RATA until the
 4576 commencement of the new recertification test period. Data
 4577 from the CEMS remain invalid until the hour in which a
 4578 new recertification test period is commenced, following
 4579 corrective action, and a probationary calibration error test is
 4580 passed, at which time the conditionally valid status of
 4581 emission data from the CEMS begins again;
 4582
- 4583 iii) If a 7-day calibration error test is failed within the
 4584 recertification test period, previously-recorded
 4585 conditionally valid emission data from the mercury CEMS
 4586 are not invalidated. The conditionally valid data status is
 4587 unaffected, unless the calibration error on the day of the
 4588 failed 7-day calibration error test exceeds twice the
 4589 performance specification in Section 3 of Exhibit A to this
 4590 Appendix, as described in subsection (b)(3)(G)(iv) of this
 4591 Section.
 4592
- 4593 iv) If a daily calibration error test is failed during a
 4594 recertification test period (i.e., the results of the test exceed
 4595 twice the performance specification in Section 3 of Exhibit
 4596 A to this Appendix), the CEMS is out-of-control as of the
 4597 hour in which the calibration error test is failed. Emission
 4598 data from the CEMS will be invalidated prospectively from
 4599 the hour of the failed calibration error test until the hour of
 4600 completion of a subsequent successful calibration error test
 4601 following corrective action, at which time the conditionally
 4602 valid status of data from the monitoring system resumes.

4603 Failure to perform a required daily calibration error test
 4604 during a recertification test period will also cause data from
 4605 the CEMS to be invalidated prospectively, from the hour in
 4606 which the calibration error test was due until the hour of
 4607 completion of a subsequent successful calibration error test.
 4608 Whenever a calibration error test is failed or missed during
 4609 a recertification test period, no further recertification tests
 4610 must be performed until the required subsequent calibration
 4611 error test has been passed, re-establishing the conditionally
 4612 valid status of data from the monitoring system. If a
 4613 calibration error test failure occurs while a linearity check
 4614 or RATA is still in progress, the linearity check or RATA
 4615 must be re-started.

v) Trial gas injections and trial RATA runs are permissible
 4617 during the recertification test period, prior to commencing a
 4618 linearity check or RATA, for the purpose of optimizing the
 4619 performance of the CEMS. The results of such gas
 4620 injections and trial runs will not affect the status of
 4621 previously-recorded conditionally valid data or result in
 4622 termination of the recertification test period, provided that
 4623 they meet the following specifications and conditions: for
 4624 gas injections, the stable, ending monitor response is within
 4625 ± 5 percent or within 5 ppm of the tag value of the
 4626 reference gas; for RATA trial runs, the average reference
 4627 method reading and the average CEMS reading for the run
 4628 differ by no more than ± 10% of the average reference
 4629 method value or ± 15 ppm, or ± 1.5% H₂O or ± 0.02
 4630 lb/mmBtu from the average reference method value, as
 4631 applicable; no adjustments to the calibration of the CEMS
 4632 are made following the trial injections or runs, other than
 4633 the adjustments permitted under Section 2.1.3 of Exhibit B
 4634 to this Appendix and the CEMS is not repaired, re-
 4635 linearized or reprogrammed (e.g., changing flow monitor
 4636 polynomial coefficients, linearity constants or K-factors)
 4637 after the trial injections or runs.

vi) If the results of any trial gas injections or RATA runs are
 4640 outside the limits in subsection (b)(3)(G)(v) of this Section
 4641 or if the CEMS is repaired, re-linearized or reprogrammed
 4642 after the trial injections or runs, the trial injections or runs
 4643 will be counted as a failed linearity check or RATA
 4644 attempt. If this occurs, follow the procedures pertaining to
 4645

failed and aborted recertification tests in subsections (b)(3)(G)(i) and (ii) of this Section.

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- H) If any required recertification test is not completed within its allotted time period, data validation must be done as follows. For a late linearity test, RATA or cycle time test that is passed on the first attempt, data from the monitoring system will be invalidated from the hour of expiration of the recertification test period until the hour of completion of the late test. For a late 7-day calibration error test, whether or not it is passed on the first attempt, data from the monitoring system will also be invalidated from the hour of expiration of the recertification test period until the hour of completion of the late test. For a late linearity test, RATA or cycle time test that is failed on the first attempt or aborted on the first attempt due to a problem with the monitor, all conditionally valid data from the monitoring system will be considered invalid back to the hour of the first probationary calibration error test that initiated the recertification test period. Data from the monitoring system will remain invalid until the hour of successful completion of the late recertification test and any additional recertification or diagnostic tests that are required as a result of changes made to the monitoring system to correct problems that caused failure of the late recertification test.
- I) If any required recertification test of a monitoring system has not been completed by the end of a calendar quarter and if data contained in the quarterly report are conditionally valid pending the results of tests to be completed in a subsequent quarter, the owner or operator must indicate this by means of a suitable conditionally valid data flag in the electronic quarterly report, and notification within the quarterly report pursuant to Section 225.290(b)(1)(E), for that quarter. The owner or operator must resubmit the report for that quarter if the required recertification test is subsequently failed. If any required recertification test is not completed by the end of a particular calendar quarter but is completed no later than 30 days after the end of that quarter (i.e., prior to the deadline for submitting the quarterly report under 40 CFR 75.64, incorporated by reference in Section 225.140), the test data and results may be submitted with the earlier quarterly report even though the test dates are from the next calendar quarter. In such instances, if the recertification tests are passed in accordance with the provisions of subsection (b)(3) of this Section, conditionally valid data may be reported as quality-assured, in lieu

of reporting a conditional data flag. In addition, if the owner or operator uses a conditionally valid data flag in any of the four quarterly reports for a given year, the owner or operator must indicate the final status of the conditionally valid data (i.e., resolved or unresolved) in the annual compliance certification report required under 40 CFR 72.90 for that year. The Agency may invalidate any conditionally valid data that remains unresolved at the end of a particular calendar year.

4) Recertification application. The designated representative must apply for recertification of each continuous mercury emission monitoring system. The owner or operator must submit the recertification application in accordance with 40 CFR 75.60, incorporated by reference in Section 225.140, and each complete recertification application must include the information specified in 40 CFR 75.63, incorporated by reference in Section 225.140.

5) Approval or disapproval of request for recertification. The procedures for provisional certification in subsection (a)(3) of this Section apply to recertification applications. The Agency will issue a notice of approval, disapproval or incompleteness according to the procedures in subsection (a)(4) of this Section. Data from the monitoring system remain invalid until all required recertification tests have been passed or until a subsequent probationary calibration error test is passed, beginning a new recertification test period. The owner or operator must repeat all recertification tests or other requirements, as indicated in the Agency's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval. The designated representative must submit a notification of the recertification retest dates, as specified in 40 CFR 75.61(a)(1)(ii), incorporated by reference in Section 225.140, and must submit a new recertification application according to the procedures in subsection (b)(4) of this Section.

c) Initial Certification and Recertification Procedures. Prior to the applicable deadline in 35 Ill. Adm. Code 225.240(b), the owner or operator must conduct initial certification tests and in accordance with 40 CFR 75.63, incorporated by reference in Section 225.140, the designated representative must submit an application to demonstrate that the continuous emission monitoring system and components of the system meet the specifications in Exhibit A to this Appendix. The owner or operator must compare reference method values with output from the automated data acquisition and handling system that is part of the continuous mercury emission monitoring system being tested. Except as otherwise specified in subsections (b)(1), (d) and (e) of this Section, and in Sections 6.3.1 and 6.3.2 of

Exhibit A to this Appendix, the owner or operator must perform the following tests for initial certification or recertification of continuous emission monitoring systems or components according to the requirements of Exhibit B to this Appendix:

- 1) For each mercury concentration monitoring system:
 - A) A 7-day calibration error test;
 - B) A linearity check, for mercury monitors, perform this check with elemental mercury standards;
 - C) A relative accuracy test audit must be done on a µg/scm basis;
 - D) A bias test;
 - E) A cycle time test;
 - F) For mercury monitors a 3-level system integrity check, using a NIST-traceable source of oxidized mercury, as described in Section 6.2 of Exhibit A to this Appendix. This test is not required for a mercury monitor that does not have a converter.

- 2) For each flow monitor:
 - A) A 7-day calibration error test;
 - B) Relative accuracy test audits, as follows:
 - i) A single-load (or single-level) RATA at the normal load (or level), as defined in Section 6.5.2.1(d) of Exhibit A to this Appendix, for a flow monitor installed on a peaking unit or bypass stack, or for a flow monitor exempted from multiple-level RATA testing under Section 6.5.2(e) of Exhibit A to this Appendix;
 - ii) For all other flow monitors, a RATA at each of the three load levels (or operating levels) corresponding to the three flue gas velocities described in Section 6.5.2(a) of Exhibit A to this Appendix;
 - C) A bias test for the single-load (or single-level) flow RATA described in subsection (c)(2)(B)(i) of this Section; and

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- D) A bias test (or bias tests) for the 3-level flow RATA described in subsection (c)(2)(B)(ii) of this Section, at the following load or operational levels:
 - i) At each load level designated as normal under Section 6.5.2.1(d) of Exhibit A to this Appendix, for units that produce electrical or thermal output, or
 - ii) At the operational level identified as normal in Section 6.5.2.1(d) of Exhibit A to this Appendix, for units that do not produce electrical or thermal output.

- 3) For each diluent gas monitor used only to monitor heat input rate:
 - A) A 7-day calibration error test;
 - B) A linearity check;
 - C) A relative accuracy test audit, where, for an O₂ monitor used to determine CO₂ concentration, the CO₂ reference method must be used for the RATA; and
 - D) A cycle-time test.

- 4) For each continuous moisture monitoring system consisting of wet- and dry-basis O₂ analyzers:
 - A) A 7-day calibration error test of each O₂ analyzer;
 - B) A cycle time test of each O₂ analyzer;
 - C) A linearity test of each O₂ analyzer; and
 - D) A RATA directly comparing the percent moisture measured by the monitoring system to a reference method.

- 5) For each continuous moisture sensor: A RATA directly comparing the percent moisture measured by the monitor sensor to a reference method.

- 6) For a continuous moisture monitoring system consisting of a temperature sensor and a data acquisition and handling system (DAHS) software component programmed with a moisture lookup table: A demonstration

- 4818 that the correct moisture value for each hour is being taken from the
 4819 moisture lookup tables and applied to the emission calculations. At a
 4820 minimum, the demonstration must be made at three different temperatures
 4821 covering the normal range of stack temperatures from low to high.
 4822
- 4823 7) For each sorbent trap monitoring system, perform a RATA, on a µg/dscm
 4824 basis, and a bias test.
 4825
- 4826 8) For the automated data acquisition and handling system, tests designed to
 4827 verify the proper computation of hourly averages for pollutant
 4828 concentrations, flow rate, pollutant emission rates and pollutant mass
 4829 emissions.
 4830
- 4831 9) The owner or operator must provide adequate facilities for initial
 4832 certification or recertification testing that include:
 4833
- 4834 A) Sampling ports adequate for test methods applicable to such
 4835 facility, such that:
 4836
- 4837 i) Volumetric flow rate, pollutant concentration and pollutant
 4838 emission rates can be accurately determined by applicable
 4839 test methods and procedures; and
 4840
- 4841 ii) A stack or duct free of cyclonic flow during performance
 4842 tests is available, as demonstrated by applicable test
 4843 methods and procedures.
 4844
- 4845 B) Basic facilities (e.g., electricity) for sampling and testing
 4846 equipment.
 4847
- 4848 d) Initial Certification and Recertification and Quality Assurance Procedures for
 4849 Optional Backup Continuous Emission Monitoring Systems.
 4850
- 4851 1) Redundant backups. The owner or operator of an optional redundant
 4852 backup CEMS must comply with all the requirements for initial
 4853 certification and recertification according to the procedures specified in
 4854 subsections (a), (b) and (c) of this Section. The owner or operator must
 4855 operate the redundant backup CEMS during all periods of unit operation,
 4856 except for periods of calibration, quality assurance, maintenance or repair.
 4857 The owner or operator must perform upon the redundant backup CEMS all
 4858 quality assurance and quality control procedures specified in Exhibit B to
 4859 this Appendix, except that the daily assessments in Section 2.1 of Exhibit
 4860 B to this Appendix are optional for days on which the redundant backup

4861 CEMS is not used to report emission data under this Part. For any day on
 4862 which a redundant backup CEMS is used to report emission data, the
 4863 system must meet all of the applicable daily assessment criteria in Exhibit
 4864 B to this Appendix.

4865
 4866 2) Non-redundant backups. The owner or operator of an optional non-
 4867 redundant backup CEMS or like-kind replacement analyzer must comply
 4868 with all of the following requirements for initial certification, quality
 4869 assurance, recertification and data reporting:

4870
 4871 A) Except as provided in subsection (d)(2)(E) of this Section, for a
 4872 regular non-redundant backup CEMS (i.e., a non-redundant backup
 4873 CEMS that has its own separate probe, sample interface and
 4874 analyzer), or a non-redundant backup flow monitor, all of the tests
 4875 in subsection (c) of this Section are required for initial certification
 4876 of the system, except for the 7-day calibration error test.

4877
 4878 B) For a like-kind replacement non-redundant backup analyzer (i.e., a
 4879 non-redundant backup analyzer that uses the same probe and
 4880 sample interface as a primary monitoring system), no initial
 4881 certification of the analyzer is required.

4882
 4883 C) Each non-redundant backup CEMS or like-kind replacement
 4884 analyzer must comply with the daily and quarterly quality
 4885 assurance and quality control requirements in Exhibit B to this
 4886 Appendix for each day and quarter that the non-redundant backup
 4887 CEMS or like-kind replacement analyzer is used to report data, and
 4888 must meet the additional linearity and calibration error test
 4889 requirements specified in this subsection. The owner or operator
 4890 must ensure that each non-redundant backup CEMS or like-kind
 4891 replacement analyzer passes a linearity check (for mercury
 4892 concentration and diluent gas monitors) or a calibration error test
 4893 (for flow monitors) prior to each use for recording and reporting
 4894 emissions. When a non-redundant backup CEMS or like-kind
 4895 replacement analyzer is brought into service, prior to conducting
 4896 the linearity test, a probationary calibration error test (as described
 4897 in subsection (b)(3)(B) of this Section), which will begin a period
 4898 of conditionally valid data, may be performed in order to allow the
 4899 validation of data retrospectively as follows. Conditionally valid
 4900 data from the CEMS or like-kind replacement analyzer are
 4901 validated back to the hour of completion of the probationary
 4902 calibration error test if the following conditions are met: if no
 4903 adjustments are made to the CEMS or like-kind replacement

4904 analyzer other than the allowable calibration adjustments specified
 4905 in Section 2.1.3 of Exhibit B to this Appendix between the
 4906 probationary calibration error test and the successful completion of
 4907 the linearity test; and if the linearity test is passed within 168 unit
 4908 (or stack) operating hours of the probationary calibration error test.
 4909 However, if the linearity test is performed within 168 unit or stack
 4910 operating hours but is either failed or aborted due to a problem
 4911 with the CEMS or like-kind replacement analyzer, then all of the
 4912 conditionally valid data are invalidated back to the hour of the
 4913 probationary calibration error test, and data from the non-
 4914 redundant backup CEMS or from the primary monitoring system
 4915 of which the like-kind replacement analyzer, is a part remain
 4916 invalid until the hour of completion of a successful linearity test.
 4917 Notwithstanding this requirement, the conditionally valid data
 4918 status may be re-established after a failed or aborted linearity
 4919 check, if corrective action is taken and a calibration error test is
 4920 subsequently passed. However, in no case will the use of
 4921 conditional data validation extend for more than 168 unit or stack
 4922 operating hours beyond the date and time of the original
 4923 probationary calibration error test when the analyzer was brought
 4924 into service.

4925
 4926 D) For each parameter monitored (i.e., CO₂, O₂, Hg or flow rate) at
 4927 each unit or stack, a regular non-redundant backup CEMS may not
 4928 be used to report data at that affected unit or common stack for
 4929 more than 720 hours in any one calendar year (in accordance with
 4930 40 CFR 75.74(c), incorporated by reference in Section 225.140),
 4931 unless the CEMS passes a RATA at that unit or stack. For each
 4932 parameter monitored at each unit or stack, the use of a like-kind
 4933 replacement non-redundant backup analyzer (or analyzers) is
 4934 restricted to 720 cumulative hours per calendar year, unless the
 4935 owner or operator redesignates the like-kind replacement analyzers
 4936 as components of regular non-redundant backup CEMS and each
 4937 redesignated CEMS passes a RATA at that unit or stack.

4938
 4939 E) For each regular non-redundant backup CEMS, no more than eight
 4940 successive calendar quarters must elapse following the quarter in
 4941 which the last RATA of the CEMS was done at a particular unit or
 4942 stack, without performing a subsequent RATA. Otherwise, the
 4943 CEMS may not be used to report data from that unit or stack until
 4944 the hour of completion of a passing RATA at that location.
 4945

- 4946 F) Each regular non-redundant backup CEMS must be represented in
 4947 the monitoring plan required under Section 1.10 of this Appendix
 4948 as a separate monitoring system, with unique system and
 4949 component identification numbers. When like-kind replacement
 4950 non-redundant backup analyzers are used, the owner or operator
 4951 must represent each like-kind replacement analyzer used during a
 4952 particular calendar quarter in the monitoring plan required under
 4953 Section 1.10 of this Appendix as a component of a primary
 4954 monitoring system. The owner or operator must also assign a
 4955 unique component identification number to each like-kind
 4956 replacement analyzer, beginning with the letters "LK" (e.g., LK1,
 4957 LK2, etc.) and must specify the manufacturer, model and serial
 4958 number of the like-kind replacement analyzer. This information
 4959 may be added, deleted or updated as necessary, from quarter to
 4960 quarter. The owner or operator must also report data from the like-
 4961 kind replacement analyzer using the system identification number
 4962 of the primary monitoring system and the assigned component
 4963 identification number of the like-kind replacement analyzer. For
 4964 the purposes of the electronic quarterly report required under 40
 4965 CFR 75.64, incorporated by reference in Section 225.140, the
 4966 owner or operator may manually enter the appropriate component
 4967 identification numbers of any like-kind replacement analyzers used
 4968 for data reporting during the quarter.
- 4969
- 4970 G) When reporting data from a certified regular non-redundant backup
 4971 CEMS, use a method of determination code (MODC) of "02".
 4972 When reporting data from a like-kind replacement non-redundant
 4973 backup analyzer, use a MODC of "17" (see Table 4a under Section
 4974 1.11 of this Appendix). For the purposes of the electronic quarterly
 4975 report required under 40 CFR 75.64, incorporated by reference in
 4976 Section 225.140, the owner or operator may manually enter the
 4977 required MODC of "17" for a like-kind replacement analyzer.
- 4978
- 4979 H) For non-redundant backup mercury CEMS and sorbent trap
 4980 monitoring systems, and for like-kind replacement mercury
 4981 analyzers, the following provisions apply in addition to, or, in
 4982 some cases, in lieu of, the general requirements in subsections
 4983 (d)(2)(A) through (H) of this Section:
- 4984
- 4985 i) When a certified sorbent trap monitoring system is brought
 4986 into service as a regular non-redundant backup monitoring
 4987 system, the system must be operated according to the

- 4988 procedures in Section 1.3 of this Appendix and Exhibit D
 4989 to this Appendix;
 4990
 4991 ii) When a regular non-redundant backup mercury CEMS or a
 4992 like-kind replacement mercury analyzer is brought into
 4993 service, a linearity check with elemental mercury standards,
 4994 as described in subsection (c)(1)(B) of this Section and
 4995 Section 6.2 of Exhibit A to this Appendix, and a single-
 4996 point system integrity check, as described in Section 2.6 of
 4997 Exhibit B to this Appendix, must be performed.
 4998 Alternatively, a 3-level system integrity check, as described
 4999 in subsection (c)(1)(E) of this Section and subsection (g) of
 5000 Section 6.2 in Exhibit A to this Appendix, may be
 5001 performed in lieu of these two tests.
 5002
 5003 iii) The weekly single-point system integrity checks described
 5004 in Section 2.6 of Exhibit B to this Appendix are required as
 5005 long as a non-redundant backup mercury CEMS or like-
 5006 kind replacement mercury analyzer remains in service,
 5007 unless the daily calibrations of the mercury analyzer are
 5008 done using a NIST-traceable source or other approved
 5009 source of oxidized mercury.
 5010
 5011 3) Reference method backups. A monitoring system that is operated as a
 5012 reference method backup system pursuant to the reference method
 5013 requirements of Methods 2, 3A, 30A and 30B in appendix A of 40 CFR
 5014 60, incorporated by reference in Section 225.140, need not perform and
 5015 pass the certification tests required by subsection (c) of this Section prior
 5016 to its use pursuant to this subsection.
 5017
 5018 e) Certification/Recertification Procedures for Either Peaking Unit or By-pass
 5019 Stack/Duct Continuous Emission Monitoring Systems. The owner or operator of
 5020 either a peaking unit or by-pass stack/duct continuous emission monitoring
 5021 system must comply with all the requirements for certification or recertification
 5022 according to the procedures specified in subsections (a), (b) and (c) of this
 5023 Section, except as follows: the owner or operator need only perform one Nine-run
 5024 relative accuracy test audit for certification or recertification of a flow monitor
 5025 installed on the by-pass stack/duct or on the stack/duct used only by affected
 5026 peaking units. The relative accuracy test audit must be performed during normal
 5027 operation of the peaking units or the by-pass stack/duct.
 5028
 5029 f) Certification/Recertification Procedures for Alternative Monitoring Systems. The
 5030 designated representative representing the owner or operator of each alternative

5031 monitoring system approved by the Agency as equivalent to or better than a
 5032 continuous emission monitoring system according to the criteria in subpart E of
 5033 40 CFR 75, incorporated by reference in Section 225.140, must apply for
 5034 certification to the Agency prior to use of the system under Subpart B of this Part,
 5035 and must apply for recertification to the Agency following a replacement,
 5036 modification, or change according to the procedures in subsection (c) of this
 5037 Section. The owner or operator of an alternative monitoring system must comply
 5038 with the notification and application requirements for certification or
 5039 recertification according to the procedures specified in subsections (a) and (b) of
 5040 this Section.

5041
 5042 **Section 1.5 Quality Assurance and Quality Control Requirements**

- 5043
- 5044 a) Continuous Emission Monitoring Systems. The owner or operator of an affected
 5045 unit must operate, calibrate and maintain each continuous mercury emission
 5046 monitoring system used to report mercury emission data as follows:
- 5047
- 5048 1) The owner or operator must operate, calibrate and maintain each primary
 5049 and redundant backup continuous emission monitoring system according
 5050 to the quality assurance and quality control procedures in Exhibit B to this
 5051 Appendix.
- 5052
- 5053 2) The owner or operator must ensure that each non-redundant backup
 5054 CEMS meets the quality assurance requirements of Section 1.4(d) of this
 5055 Appendix for each day and quarter that the system is used to report data.
- 5056
- 5057 3) The owner or operator must perform quality assurance upon a reference
 5058 method backup monitoring system according to the requirements of
 5059 Method 2 or 3A in appendix A of 40 CFR 60, incorporated by reference in
 5060 Section 225.140 (supplemented, as necessary, by guidance from the
 5061 Administrator or the Agency), or one of the mercury reference methods in
 5062 Section 1.6 of this Appendix, as applicable, instead of the procedures
 5063 specified in Exhibit B of this Appendix.
- 5064
- 5065 b) Calibration Gases. The owner or operator must ensure that all calibration gases
 5066 used to quality assure the operation of the instrumentation required by this
 5067 Appendix must meet the definition in 40 CFR 72.2, incorporated by reference in
 5068 Section 225.140.

5069

5070 **Section 1.6 Reference Test Methods**

- 5071
- 5072 a) The owner or operator must use the following methods, which are found in
 5073 appendix A-4 to 40 CFR 60, incorporated by reference in Section 225.140, or

5074 have been published by ASTM, to conduct the following tests: monitoring system
 5075 tests for certification or recertification of continuous mercury emission
 5076 monitoring systems; the emission tests required under Section 1.15(c) and (d) of
 5077 this Appendix; and required quality assurance and quality control tests:
 5078

- 5079 1) Methods 1 or 1A are the reference methods for selection of sampling site
 5080 and sample traverses.
- 5081
- 5082 2) Method 2 or its allowable alternatives, as provided in appendix A to 40
 5083 CFR 60, incorporated by reference in Section 225.140, except for Methods
 5084 2B and 2E, are the reference methods for determination of volumetric
 5085 flow.
- 5086
- 5087 3) Methods 3, 3A or 3B are the reference methods for the determination of
 5088 the dry molecular weight O₂ and CO₂ concentrations in the emissions.
 5089
- 5090 4) Method 4 (either the standard procedure described in Section 8.1 of the
 5091 method or the moisture approximation procedure described in Section 8.2
 5092 of the method) must be used to correct pollutant concentrations from a dry
 5093 basis to a wet basis (or from a wet basis to a dry basis) and must be used
 5094 when relative accuracy test audits of continuous moisture monitoring
 5095 systems are conducted. For the purpose of determining the stack gas
 5096 molecular weight, however, the alternative wet bulb-dry bulb technique
 5097 for approximating the stack gas moisture content described in Section 2.2
 5098 of Method 4 may be used in lieu of the procedures in Sections 8.1 and 8.2
 5099 of the method.
- 5100
- 5101 5) ASTM D6784-02, Standard Test Method for Elemental, Oxidized,
 5102 Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired
 5103 Stationary Sources (Ontario Hydro Method) (incorporated by reference
 5104 under Section 225.140) is the reference method for determining mercury
 5105 concentration.
- 5106
- 5107 A) Alternatively, Method 29 in appendix A-8 to 40 CFR 60,
 5108 incorporated by reference in Section 225.140, may be used, with
 5109 these caveats: The procedures for preparation of mercury standards
 5110 and sample analysis in Sections 13.4.1.1 through 13.4.1.3 ASTM
 5111 D6784-02 (incorporated by reference under Section 225.140) must
 5112 be followed instead of the procedures in Sections 7.5.33 and 11.1.3
 5113 of Method 29 in appendix A-8 to 40 CFR 60, and the QA/QC
 5114 procedures in Section 13.4.2 of ASTM D6784-02 (incorporated by
 5115 reference under Section 225.140) must be performed instead of the
 5116 procedures in Section 9.2.3 of Method 29 in appendix A-8 to 40

CFR 60. The tester may also opt to use the sample recovery and preparation procedures in ASTM D6784-02 (incorporated by reference under Section 225.140) instead of the Method 29 in appendix A-8 to 40 CFR 60 procedures, as follows: Sections 8.2.8 and 8.2.9.1 of Method 29 in appendix A-8 to 40 CFR 60 may be replaced with Sections 13.2.9.1 through 13.2.9.3 of ASTM D6784-02 (incorporated by reference under Section 225.140); Sections 8.2.9.2 and 8.2.9.3 of Method 29 in appendix A-8 to 40 CFR 60 may be replaced with Sections 13.2.10.1 through 13.2.10.4 of ASTM D6784-02 (incorporated by reference under Section 225.140); Section 8.3.4 of Method 29 in appendix A-8 to 40 CFR 60 may be replaced with Section 13.3.4 or 13.3.6 of ASTM D6784-02 (as appropriate) (incorporated by reference under Section 225.140); and Section 8.3.5 of Method 29 in appendix A-8 to 40 CFR 60 may be replaced with Section 13.3.5 or 13.3.6 of ASTM D6784-02 (as appropriate) (incorporated by reference under Section 225.140).

B) Whenever ASTM D6784-02 (incorporated by reference under Section 225.140) or Method 29 in appendix A-8 to 40 CFR 60, incorporated by reference in Section 225.140 is used, paired sampling trains are required. To validate a RATA run or an emission test run, the relative deviation (RD), calculated according to Section 11.6 of Exhibit D to this Appendix, must not exceed 10 percent when the average concentration is greater than 1.0 $\mu\text{g}/\text{m}^3$. If the average concentration is less than or equal to 1.0 $\mu\text{g}/\text{m}^3$, the RD must not exceed 20 percent. The RD results are also acceptable if the absolute difference between the mercury concentrations measured by the paired trains does not exceed 0.03 $\mu\text{g}/\text{m}^3$. If the RD criterion is met, the run is valid. For each valid run, average the mercury concentrations measured by the two trains (vapor phase only).

C) Two additional reference methods that may be used to measure mercury concentration are: Method 30A, Determination of Total Vapor Phase Mercury Emissions from Stationary Sources (Instrumental Analyzer Procedure) and Method 30B, Determination of Total Vapor Phase Mercury Emissions from Coal-Fired Combustion Sources Using Carbon Sorbent Traps.

D) When Method 29 in appendix A-8 to 40 CFR 60, incorporated by reference in Section 225.140, or ASTM D6784-02 (incorporated by reference under Section 225.140) is used for the mercury

5160 emission testing required under Section 1.15(c) and (d) of this
 5161 Appendix, locate the reference method test points according to
 5162 Section 8.1 of Method 30A, and if mercury stratification testing is
 5163 part of the test protocol, follow the procedures in Sections 8.1.3
 5164 through 8.1.3.5 of Method 30A.
 5165

5166 b) The owner or operator may use any of the following methods, which are found in
 5167 appendix A to 40 CFR 60, incorporated by reference in Section 225.140, or have
 5168 been published by ASTM, as a reference method backup monitoring system to
 5169 provide quality-assured monitor data:
 5170

- 5171 1) Method 3A for determining O₂ or CO₂ concentration;
- 5172
- 5173 2) Method 2, or its allowable alternatives, as provided in appendix A to 40
 5174 CFR 60, incorporated by reference in Section 225.140, except for Methods
 5175 2B and 2E, for determining volumetric flow. The sample points for
 5176 reference methods must be located according to the provisions of Section
 5177 6.5.4 of Exhibit A to this Appendix.
- 5178
- 5179 3) ASTM D6784-02, Standard Test Method for Elemental, Oxidized,
 5180 Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired
 5181 Stationary Sources (Ontario Hydro Method) (incorporated by reference
 5182 under Section 225.140) for determining mercury concentration;
 5183
- 5184 4) Method 29 in appendix A-8 to 40 CFR 60, incorporated by reference in
 5185 Section 225.140, for determining mercury concentration;
 5186
- 5187 5) Method 30A for determining mercury concentration; and
- 5188
- 5189 6) Method 30B for determining mercury concentration.
 5190

5191 c) Instrumental EPA Reference Method 3A in appendices A-2 and A-4 of 40 CFR
 5192 60, incorporated by reference in Section 225.140, must be conducted using
 5193 calibration gases as defined in Section 5 of Exhibit A to this Appendix.
 5194 Otherwise, performance tests must be conducted and data reduced in accordance
 5195 with the test methods and procedures of this Part unless the Agency:
 5196

- 5197 1) Specifies or approves, in specific cases, the use of a reference method with
 5198 minor changes in methodology;
- 5199
- 5200 2) Approves the use of an equivalent method; or
 5201

- 5202 3) Approves shorter sampling times and smaller sample volumes when
 5203 necessitated by process variables or other factors.
 5204

5205 **Section 1.7 Out-of-Control Periods and System Bias Testing**
 5206

- 5207 a) If an out-of-control period occurs to a monitor or continuous emission monitoring
 5208 system, the owner or operator must take corrective action and repeat the tests
 5209 applicable to the out-of-control parameter as described in Exhibit B to this
 5210 Appendix.
 5211
- 5212 1) For daily calibration error tests, an out-of-control period occurs when the
 5213 calibration error of a pollutant concentration monitor exceeds the
 5214 applicable specification in Section 2.1.4 of Exhibit B to this Appendix.
 5215
- 5216 2) For quarterly linearity checks, an out-of-control period occurs when the
 5217 error in linearity at any of three gas concentrations (low, mid-range and
 5218 high) exceeds the applicable specification in Exhibit A to this Appendix.
 5219
- 5220 3) For relative accuracy test audits, an out-of-control period occurs when the
 5221 relative accuracy exceeds the applicable specification in Exhibit A to this
 5222 Appendix.
 5223
- 5224 b) When a monitor or continuous emission monitoring system is out-of-control, any
 5225 data recorded by the monitor or monitoring system are not quality-assured and
 5226 must not be used in calculating monitor data availabilities pursuant to Section 1.8
 5227 of this Appendix.
 5228
- 5229 c) When a monitor or continuous emission monitoring system is out-of-control, the
 5230 owner or operator must take one of the following actions until the monitor or
 5231 monitoring system has successfully met the relevant criteria in Exhibits A and B
 5232 of this Appendix as demonstrated by subsequent tests:
 5233
- 5234 1) Use a certified backup monitoring system or a reference method for
 5235 measuring and recording emissions from the affected units; or
 5236
- 5237 2) Adjust the gas discharge paths from the affected units with emissions
 5238 normally observed by the out-of-control monitor or monitoring system so
 5239 that all exhaust gases are monitored by a certified monitor or monitoring
 5240 system meeting the requirements of Exhibits A and B to this Appendix.
 5241
- 5242 d) When the bias test indicates that a flow monitor, a diluent monitoring system, a
 5243 mercury concentration monitoring system or a sorbent trap monitoring system is
 5244 biased low (i.e., the arithmetic mean of the differences between the reference

5245 method value and the monitor or monitoring system measurements in a relative
 5246 accuracy test audit exceed the bias statistic in Section 7 of Exhibit A to this
 5247 Appendix), the owner or operator must adjust the monitor or continuous emission
 5248 monitoring system to eliminate the cause of bias such that it passes the bias test.
 5249

5250 **Section 1.8 Determination of Monitor Data Availability**

5251
 5252 a) Following initial certification of the required CO₂ O₂ flow monitoring systems,
 5253 Hg concentration or moisture monitoring systems at a particular unit or stack
 5254 location (i.e., the date and time at which quality-assured data begins to be
 5255 recorded by CEMSs at that location), the owner or operator must begin
 5256 calculating the percent monitor data availability as described in subsection (a)(1)
 5257 of this Section, by means of the automated data acquisition and handling system,
 5258 and the percent monitor data availability for each monitored parameter.
 5259

5260 1) Following initial certification, the owner or operator must use Equation 8
 5261 to calculate, hourly, percent monitor data availability for each calendar
 5262 quarter.
 5263

5264 Total unit operating hours for which quality-assured data Percent was
 5265 recorded for the calendar quarter monitor data = X 100 (Eq.8)
 5266 Availability Total unit operating hours for the calendar quarter
 5267

5268 2) When calculating percent monitor data availability using Equation 8, the
 5269 owner or operator must include all unit operating hours, and all monitor
 5270 operating hours for which quality-assured data were recorded by a
 5271 certified primary monitor; a certified redundant or non-redundant backup
 5272 monitor or a reference method for that unit.
 5273

5274 **Section 1.9 Determination of Sorbent Trap Monitoring Systems Data Availability**

5275
 5276 a) If a primary sorbent trap monitoring system has not been certified by the
 5277 applicable compliance date specified under Subpart B of this Part, and if quality-
 5278 assured mercury concentration data from a certified backup mercury monitoring
 5279 system, reference method or approved alternative monitoring system are
 5280 unavailable, the owner or operator must perform quarterly emissions testing in
 5281 accordance with Section 225.239 until such time the primary sorbent trap
 5282 monitoring system has been certified.
 5283

5284 b) For a certified sorbent trap system, a missing data period will occur in the
 5285 following circumstances, unless quality-assured mercury concentration data from
 5286 a certified backup mercury CEMS, sorbent trap system, reference method or
 5287 approved alternative monitoring system are available:

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- 1) A gas sample is not extracted from the stack during unit operation (e.g., during a monitoring system malfunction or when the system undergoes maintenance); or
 - 2) The results of the mercury analysis for the paired sorbent traps are missing or invalid (as determined using the quality assurance procedures in Exhibit D to this Appendix). The missing data period begins with the hour in which the paired sorbent traps for which the mercury analysis is missing or invalid were put into service. The missing data period ends at the first hour in which valid mercury concentration data are obtained with another pair of sorbent traps (i.e., the hour at which this pair of traps was placed in service), or with a certified backup mercury CEMS, reference method or approved alternative monitoring system.
 - c) Following initial certification of the sorbent trap monitoring system, begin reporting the percent monitor data availability in accordance with Section 1.8 of this Appendix.

5307 **Section 1.10 Monitoring Plan**

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- a) The owner or operator of an affected unit must prepare and maintain a mercury emissions monitoring plan.
 - b) Whenever the owner or operator makes a replacement, modification or change in the certified CEMS, including a change in the automated data acquisition and handling system or in the flue gas handling system, that affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), then the owner or operator must update the monitoring plan, by the applicable deadline specified in 40 CFR 75.62, incorporated by reference in Section 225.140, or elsewhere in this Appendix.
 - c) Contents of Monitoring Plan for Specific Situations. The following additional information must be included in the monitoring plan for the specific situations described. For each monitoring system recertification, maintenance or other event, the designated representative must include the following additional information in electronic format in the monitoring plan:
 - 1) Component/system identification code;
 - 2) Event code or code for required test;
 - 3) Event begin date and hour;

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- 4) Conditionally valid data period begin date and hour (if applicable);
- 5) Date and hour that last test is successfully completed; and
- 6) Indicator of whether conditionally valid data were reported at the end of the quarter.

d) Contents of the Mercury Monitoring Plan. The requirements of subsection (d) of this Section must be met on and after July 1, 2009. Each monitoring plan must contain the information in subsection (d)(1) of this Section in electronic format and the information in subsection (d)(2) of this Section in hardcopy format. Electronic storage of all monitoring plan information, including the hardcopy portions, is permissible provided that a paper copy of the information can be furnished upon request for audit purposes.

1) Electronic

A) The facility ORISPL number developed by the Department of Energy and used in the National Allowance Data Base (or equivalent facility ID number assigned by USEPA, if the facility does not have an ORISPL number). Also provide the following information for each unit and (as applicable) for each common stack and/or pipe, and each multiple stack and/or pipe involved in the monitoring plan:

i) A representation of the exhaust configuration for the units in the monitoring plan. Provide the ID number of each unit and assign a unique ID number to each common stack, common pipe, multiple stack and/or multiple pipe associated with the units represented in the monitoring plan. For common and multiple stacks and/or pipes, provide the activation date and deactivation date (if applicable) of each stack and/or pipe;

ii) Identification of the monitoring system locations (e.g., at the unit-level, on the common stack, at each multiple stack, etc.). Provide an indicator (flag) if the monitoring location is at a bypass stack or in the ductwork (breeching);

iii) The stack exit height (ft) above ground level and ground level elevation above sea level, and the inside cross-sectional area (ft²) at the flue exit and at the flow

- 5374 monitoring location (for units with flow monitors only).
 5375 Also use appropriate codes to indicate the materials of
 5376 construction and the shapes of the stack or duct cross-
 5377 sections at the flue exit and (if applicable) at the flow
 5378 monitor location;
 5379
 5380 iv) The types of fuels fired by each unit. Indicate the start and
 5381 (if applicable) end date of combustion for each type of fuel,
 5382 and whether the fuel is the primary, secondary, emergency
 5383 or startup fuel;
 5384
 5385 v) The types of emission controls that are used to reduce
 5386 mercury emissions from each unit. Also provide the
 5387 installation date, optimization date and retirement date (if
 5388 applicable) of the emission controls, and indicate whether
 5389 the controls are an original installation; and
 5390
 5391 vi) Maximum hourly heat input capacity of each unit.
 5392
 5393 B) For each monitored parameter (i.e., mercury concentration, diluent
 5394 concentration or flow) at each monitoring location, specify the
 5395 monitoring methodology for the parameter. If the unmonitored
 5396 bypass stack approach is used for a particular parameter, indicate
 5397 this by means of an appropriate code. Provide the activation
 5398 date/hour, and deactivation date/hour (if applicable) for each
 5399 monitoring methodology.
 5400
 5401 C) For each required continuous emission monitoring system and each
 5402 sorbent trap monitoring system (as defined in Section 225.130),
 5403 identify and describe the major monitoring components in the
 5404 monitoring system (e.g., gas analyzer, flow monitor, moisture
 5405 sensor, DAHS software, etc.). Other important components in the
 5406 system (e.g., sample probe, PLC, data logger, etc.) may also be
 5407 represented in the monitoring plan, if necessary. Provide the
 5408 following specific information about each component and
 5409 monitoring system:
 5410
 5411 i) For each required monitoring system, assign a unique, 3-
 5412 character alphanumeric identification code to the system;
 5413 indicate the parameter monitored by the system; designate
 5414 the system as a primary, redundant backup, non-redundant
 5415 backup, data backup or reference method backup system, as
 5416 provided in Section 1.2(d) of this Appendix; and indicate

- 5417 the system activation date/hour and deactivation date/hour
 5418 (as applicable).
 5419
 5420 ii) For each component of each monitoring system represented
 5421 in the monitoring plan, assign a unique, 3-character
 5422 alphanumeric identification code to the component;
 5423 indicate the manufacturer, model and serial number;
 5424 designate the component type; for gas analyzers, indicate
 5425 the moisture basis of measurement; indicate the method of
 5426 sample acquisition or operation, (e.g., extractive pollutant
 5427 concentration monitor or thermal flow monitor); and
 5428 indicate the component activation date/hour and
 5429 deactivation date/hour (as applicable).
 5430
 5431 D) Explicit formulas, using the component and system identification
 5432 codes for the primary monitoring system, and containing all
 5433 constants and factors required to derive the required emission rates,
 5434 heat input rates, etc. from the hourly data recorded by the
 5435 monitoring systems. Formulas using the system and component ID
 5436 codes for backup monitoring systems are required only if different
 5437 formulas for the same parameter are used for the primary and
 5438 backup monitoring systems (e.g., if the primary system measures
 5439 pollutant concentration on a different moisture basis from the
 5440 backup system). Provide the equation number or other appropriate
 5441 code for each emissions formula (e.g., use code F-1 if Equation F-1
 5442 in Exhibit C to this Appendix is used to calculate SO₂ mass
 5443 emissions). Also identify each emissions formula with a unique
 5444 three character alphanumeric code. The formula effective start
 5445 date/hour and inactivation date/hour (as applicable) must be
 5446 included for each formula.
 5447
 5448 E) For each parameter monitored with CEMS, provide the following
 5449 information:
 5450
 5451 i) Measurement scale;
 5452
 5453 ii) Maximum potential value (and method of calculation);
 5454
 5455 iii) Maximum expected value (if applicable) and method of
 5456 calculation;
 5457
 5458 iv) Span values and full-scale measurement ranges;
 5459

- 5460 v) Daily calibration units of measure;
- 5461
- 5462 vi) Effective date/hour, and (if applicable) inactivation
- 5463 date/hour of each span value;
- 5464
- 5465 vii) The default high range value (if applicable) and the
- 5466 maximum allowable low-range value for this option.
- 5467
- 5468 F) If the monitoring system or excepted methodology provides for the
- 5469 use of a constant, assumed or default value for a parameter under
- 5470 specific circumstances, then include the following information for
- 5471 each such value for each parameter:
- 5472
- 5473 i) Identification of the parameter;
- 5474
- 5475 ii) Default, maximum, minimum, or constant value, and units
- 5476 of measure for the value;
- 5477
- 5478 iii) Purpose of the value;
- 5479
- 5480 iv) Indicator of use, i.e., during controlled hours, uncontrolled
- 5481 hours or all operating hours;
- 5482
- 5483 v) Type of fuel;
- 5484
- 5485 vi) Source of the value;
- 5486
- 5487 vii) Value effective date and hour;
- 5488
- 5489 viii) Date and hour value is no longer effective (if applicable);
- 5490 and
- 5491
- 5492 G) Unless otherwise specified in Section 6.5.2.1 of Exhibit A to this
- 5493 Appendix, for each unit or common stack on which hardware
- 5494 CEMS are installed:
- 5495
- 5496 i) Maximum hourly gross load (in MW, rounded to the
- 5497 nearest MW, or steam load in 1000 lb/hr (i.e., klb/hr),
- 5498 rounded to the nearest klb/hr, or thermal output in
- 5499 mmBtu/hr, rounded to the nearest mmBtu/hr), for units that
- 5500 produce electrical or thermal output;
- 5501
- 5502 ii) The upper and lower boundaries of the range of operation

- 5503 (as defined in Section 6.5.2.1 of Exhibit A to this
 5504 Appendix), expressed in megawatts, thousands of lb/hr of
 5505 steam, mmBtu/hr of thermal output or ft/sec (as
 5506 applicable);
- 5507
- 5508 iii) Except for peaking units, identify the most frequently and
 5509 second most frequently used load (or operating) levels (i.e.,
 5510 low, mid or high) in accordance with Section 6.5.2.1 of
 5511 Exhibit A to this Appendix, expressed in megawatts,
 5512 thousands of lb/hr of steam, mmBtu/hr of thermal output or
 5513 ft/sec (as applicable);
- 5514
- 5515 iv) An indicator of whether the second most frequently used
 5516 load (or operating) level is designated as normal in Section
 5517 6.5.2.1 of Exhibit A to this Appendix;
- 5518
- 5519 v) The date of the data analysis used to determine the normal
 5520 load (or operating) levels and the two most frequently-used
 5521 load (or operating) levels (as applicable); and
- 5522
- 5523 vi) Activation and deactivation dates and hours, when the
 5524 maximum hourly gross load, boundaries of the range of
 5525 operation, normal load (or operating) levels or two most
 5526 frequently-used load (or operating) levels change and are
 5527 updated.
- 5528
- 5529 H) For each unit for which CEMS are not installed, the maximum
 5530 hourly gross load (in MW, rounded to the nearest MW, or steam
 5531 load in klb/hr, rounded to the nearest klb/hr or steam load in
 5532 mmBtu/hr, rounded to the nearest mmBtu/hr);
- 5533
- 5534 I) For each unit with a flow monitor installed on a rectangular stack
 5535 or duct, if a wall effects adjustment factor (WAF) is determined
 5536 and applied to the hourly flow rate data:
- 5537
- 5538 i) Stack or duct width at the test location, ft;
- 5539
- 5540 ii) Stack or duct depth at the test location, ft;
- 5541
- 5542 iii) Wall effects adjustment factor (WAF), to the nearest
 5543 0.0001;
- 5544
- 5545 iv) Method of determining the WAF;

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- v) WAF effective date and hour;
- vi) WAF no longer effective date and hour (if applicable);
- vii) WAF determination date;
- viii) Number of WAF test runs;
- ix) Number of Method 1 traverse points in the WAF test;
- x) Number of test ports in the WAF test; and
- xi) Number of Method 1 traverse points in the reference flow RATA.

2) Hardcopy

- A) Information, including (as applicable): Identification of the test strategy; protocol for the relative accuracy test audit; other relevant test information; calibration gas levels (percent of span) for the calibration error test and linearity check and span; and apportionment strategies under Sections 1.2 and 1.3 of this Appendix.
- B) Description of site locations for each monitoring component in the continuous emission monitoring systems, including schematic diagrams and engineering drawings specified in 40 CFR 75.53(e)(2)(iv) and (v), incorporated by reference in Section 225.140 and any other documentation that demonstrates each monitor location meets the appropriate siting criteria.
- C) A data flow diagram denoting the complete information handling path from output signals of CEMS components to final reports.
- D) For units monitored by a continuous emission monitoring system, a schematic diagram identifying entire gas handling system from boiler to stack for all affected units, using identification numbers for units, monitoring systems and components and stacks corresponding to the identification numbers provided in subsections (d)(1)(A) and (C) of this Section. The schematic diagram must depict stack height and the height of any monitor locations. Comprehensive and/or separate schematic diagrams

5589 must be used to describe groups of units using a common stack.

5590
5591 E) For units monitored by a continuous emission monitoring system,
5592 stack and duct engineering diagrams showing the dimensions and
5593 location of fans, turning vanes, air preheaters, monitor
5594 components, probes, reference method sampling ports and other
5595 equipment that affects the monitoring system location,
5596 performance or quality control checks.
5597

5598 **Section 1.11 General Recordkeeping Provisions**

5599
5600 The owner or operator must meet all of the applicable recordkeeping requirements of Section
5601 225.290 and of this Section.
5602

5603 a) Recordkeeping Requirements for Affected Sources. The owner or operator of any
5604 affected source subject to the requirements of this Appendix must maintain for
5605 each affected unit a file of all measurements, data, reports and other information
5606 required by Subpart B of this Part at the source in a form suitable for inspection
5607 for at least 3 years from the date of each record. The file must contain the
5608 following information:
5609

5610 1) The data and information required in subsections (b) through (h) of this
5611 Section, beginning with the earlier of the date of provisional certification
5612 or July 1, 2009;
5613

5614 2) The supporting data and information used to calculate values required in
5615 subsection (b) through (g) of this Section, excluding the subhourly data
5616 points used to compute hourly averages under Section 1.2(c) of this
5617 Appendix, beginning with the earlier of the date of provisional
5618 certification or July 1, 2009;
5619

5620 3) The data and information required in Section 1.12 of this Appendix for
5621 specific situations, beginning with the earlier of the date of provisional
5622 certification or July 1, 2009;
5623

5624 4) The certification test data and information required in Section 1.13 of this
5625 Appendix for tests required under Section 1.4 of this Appendix, beginning
5626 with the date of the first certification test performed, the quality assurance
5627 and quality control data and information required in Section 1.13 of this
5628 Appendix for tests, and the quality assurance/quality control plan required
5629 under Section 1.5 of this Appendix and Exhibit B to this Appendix,
5630 beginning with the date of provisional certification;
5631

- 5632 5) The current monitoring plan as specified in Section 1.10 of this Appendix,
 5633 beginning with the initial submission required by 40 CFR 75.62,
 5634 incorporated by reference in Section 225.140; and
 5635
- 5636 6) The quality control plan as described in Section 1 of Exhibit B to this
 5637 Appendix, beginning with the date of provisional certification.
 5638
- 5639 b) Operating Parameter Record Provisions. The owner or operator must record for
 5640 each hour the following information on unit operating time, heat input rate and
 5641 load, separately for each affected unit and also for each group of units utilizing a
 5642 common stack and a common monitoring system:
 5643
- 5644 1) Date and hour;
 5645
- 5646 2) Unit operating time (rounded up to the nearest fraction of an hour (in
 5647 equal increments that can range from one hundredth to one quarter of an
 5648 hour, at the option of the owner or operator));
 5649
- 5650 3) Hourly gross unit load (rounded to nearest MWge)
 5651
- 5652 4) Steam load in 1000 lbs/hr at stated temperatures and pressures, rounded to
 5653 the nearest 1000 lbs/hr.
 5654
- 5655 5) Operating load range corresponding to hourly gross load of 1 to 10, except
 5656 for units using a common stack, which may use up to 20 load ranges for
 5657 stack or fuel flow, as specified in the monitoring plan;
 5658
- 5659 6) Hourly heat input rate (mmBtu/hr, rounded to the nearest tenth);
 5660
- 5661 7) Identification code for formula used for heat input as provided in Section
 5662 1.10 of this Appendix; and
 5663
- 5664 8) For Mercury CEMS units only, F-factor for heat input calculation and
 5665 indication of whether the diluent cap was used for heat input calculations
 5666 for the hour.
 5667
- 5668 c) Diluent Record Provisions. The owner or operator of a unit using a flow monitor
 5669 and an O₂ diluent monitor to determine heat input, in accordance with Equation F-
 5670 17 or F-18 of Exhibit C to this Appendix, or a unit that accounts for heat input
 5671 using a flow monitor and a CO₂ diluent monitor (which is used only for heat input
 5672 determination and is not used as a CO₂ pollutant concentration monitor) must
 5673 keep the following records for the O₂ or CO₂ diluent monitor:
 5674

- 5675 1) Component-system identification code as provided in Section 1.10 of this
 5676 Appendix;
 5677
- 5678 2) Date and hour;
 5679
- 5680 3) Hourly average diluent gas (O₂ or CO₂) concentration (in percent, rounded
 5681 to the nearest tenth);
 5682
- 5683 4) Percent monitor data availability for the diluent monitor (recorded to the
 5684 nearest tenth of a percent) calculated pursuant to Section 1.8 of this
 5685 Appendix; and
 5686
- 5687 5) Method of determination code for diluent gas (O₂ or CO₂) concentration
 5688 data using Codes 1-55 in Table 4a of this Section.
 5689
- 5690 d) Missing Data Records. The owner or operator must record the causes of any
 5691 missing data periods and the actions taken by the owner or operator to correct
 5692 such causes.
 5693
- 5694 e) Mercury Emission Record Provisions (CEMS). The owner or operator must
 5695 record for each hour the information required by this subsection for each affected
 5696 unit using mercury CEMS in combination with flow rate, and (in certain cases)
 5697 moisture, and diluent gas monitors, to determine mercury concentration and (if
 5698 applicable) unit heat input under Subpart B of this Part.
 5699
- 5700 1) For mercury concentration during unit operation, as measured and
 5701 reported from each certified primary monitor, certified back-up monitor or
 5702 other approved method of emissions determination:
 5703
- 5704 A) Component-system identification code as provided in Section 1.10
 5705 of this Appendix;
 5706
- 5707 B) Date and hour;
 5708
- 5709 C) Hourly mercury concentration (µg/scm, rounded to the nearest
 5710 tenth). For a particular pair of sorbent traps, this will be the flow-
 5711 proportional average concentration for the data collection period;
 5712
- 5713 D) Method of determination for hourly mercury concentration using
 5714 Codes 1-55 in Table 4a of this Section; and
 5715
- 5716 E) The percent monitor data availability (to the nearest tenth of a
 5717 percent) calculated pursuant to Section 1.8 of this Appendix.

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- 2) For flue gas moisture content during unit operation (if required), as measured and reported from each certified primary monitor, certified back-up monitor or other approved method of emissions determination (except where a default moisture value is approved under 40 CFR 75.66, incorporated by reference in Section 225.140):
 - A) Component-system identification code as provided in Section 1.10 of this Appendix;
 - B) Date and hour;
 - C) Hourly average moisture content of flue gas (percent, rounded to the nearest tenth). If the continuous moisture monitoring system consists of wet-and dry-basis oxygen analyzers, also record both the wet- and dry-basis oxygen hourly averages (in percent O₂, rounded to the nearest tenth);
 - D) Percent monitor data availability (recorded to the nearest tenth of a percent) for the moisture monitoring system calculated pursuant to Section 1.8 of this Appendix; and
 - E) Method of determination for hourly average moisture percentage using Codes 1-55 in Table 4a of this Section.

- 3) For diluent gas (O₂ or CO₂) concentration during unit operation (if required), as measured and reported from each certified primary monitor, certified back-up monitor or other approved method of emissions determination:
 - A) Component-system identification code as provided in Section 1.10 of this Appendix;
 - B) Date and hour;
 - C) Hourly average diluent gas (O₂ or CO₂) concentration (in percent, rounded to the nearest tenth);
 - D) Method of determination code for diluent gas (O₂ or CO₂) concentration data using Codes 1-55 in Table 4a of this Section; and
 - E) The percent monitor data availability (to the nearest tenth of a

percent) for the O₂ or CO₂ monitoring system (if a separate O₂ or CO₂ monitoring system is used for heat input determination) calculated pursuant to Section 1.8 of this Appendix.

4) For stack gas volumetric flow rate during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor or other approved method of emissions determination, record the information required under 40 CFR 75.57(c)(2)(i) through (vi), incorporated by reference in Section 225.140.

5) For mercury mass emissions during unit operation, as measured and reported from the certified primary monitoring systems, certified redundant or non-redundant back-up monitoring systems, or other approved methods of emissions determination:

A) Date and hour;

B) Hourly mercury mass emissions (ounces, rounded to three decimal places);

C) Identification code for emissions formula used to derive hourly mercury mass emissions from mercury concentration, flow rate and moisture data, as provided in Section 1.10 of this Appendix.

f) Mercury Emission Record Provisions (Sorbent Trap Systems). The owner or operator must record for each hour the information required by this subsection, for each affected unit using sorbent trap monitoring systems in combination with flow rate, moisture, and (in certain cases) diluent gas monitors, to determine mercury mass emissions and (if required) unit heat input under this Part.

1) For mercury concentration during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor or other approved method of emissions determination:

A) Component-system identification code as provided in Section 1.10 of this Appendix;

B) Date and hour;

C) Hourly mercury concentration ($\mu\text{g}/\text{dscm}$, rounded to the nearest tenth). For a particular pair of sorbent traps, this will be the flow-proportional average concentration for the data collection period;

- 5804 D) Method of determination for hourly average mercury concentration
- 5805 using Codes 1-55 in Table 4a of this Section; and
- 5806
- 5807 E) Percent monitor data availability (recorded to the nearest tenth of a
- 5808 percent) calculated pursuant to Section 1.8 of this Appendix;
- 5809
- 5810 2) For flue gas moisture content during unit operation, as measured and
- 5811 reported from each certified primary monitor, certified back-up monitor or
- 5812 other approved method of emissions determination (except where a default
- 5813 moisture value is approved under 40 CFR 75.66, incorporated by reference
- 5814 in Section 225.140), record the information required under subsections
- 5815 (e)(2)(A) through (E) of this Section;
- 5816
- 5817 3) For diluent gas (O₂ or CO₂) concentration during unit operation (if
- 5818 required for heat input determination), record the information required
- 5819 under subsections (e)(3)(A) through (E) of this Section.
- 5820
- 5821 4) For stack gas volumetric flow rate during unit operation, as measured and
- 5822 reported from each certified primary monitor, certified back-up monitor or
- 5823 other approved method of emissions determination, record the information
- 5824 required under 40 CFR 75.57(c)(2)(i) through (vi), incorporated by
- 5825 reference in Section 225.140.
- 5826
- 5827 5) For mercury mass emissions during unit operation, as measured and
- 5828 reported from the certified primary monitoring systems, certified
- 5829 redundant or non-redundant back-up monitoring systems or other
- 5830 approved methods of emissions determination, record the information
- 5831 required under subsection (e)(5) of this Section.
- 5832
- 5833 6) Record the average flow rate of stack gas through each sorbent trap (in
- 5834 appropriate units, e.g., liters/min, cc/min, dscm/min).
- 5835
- 5836 7) Record the gas flow meter reading (in dscm, rounded to the nearest
- 5837 hundredth) at the beginning and end of the collection period and at least
- 5838 once in each unit operating hour during the collection period.
- 5839
- 5840 8) Calculate and record the ratio of the bias-adjusted stack gas flow rate to
- 5841 the sample flow rate, as described in Section 11.2 of Exhibit D to this
- 5842 Appendix.

5843

5844 Table 4a. – Codes for Method of Emissions and Flow Determination Code

5845 Hourly emissions/flow measurement or estimation method

5846

- 1 Certified primary emission/flow monitoring system.
- 2 Certified backup emission/flow monitoring system.
- 3 Approved alternative monitoring system.
- 4 Reference method.
- 17 Like-kind replacement non-redundant backup analyzer.
- 32 Hourly Hg concentration determined from analysis of a single trap multiplied by a factor of 1.111 when one of the paired traps is invalidated or damaged (See Appendix K, Section 8).
- 33 Hourly Hg concentration determined from the trap resulting in the higher Hg concentration when the relative deviation criterion for the paired traps is not met (See Appendix K, Section 8).
- 40 Fuel specific default value (or prorated default value) used for the hour.
- 54 Other quality assured methodologies approved through petition. These hours are included in missing data lookback and are treated as unavailable hours for percent monitor availability calculations.
- 55 Other substitute data approved through petition. These hours are not included in missing data lookback and are treated as unavailable hours for percent monitor availability calculations.

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Section 1.12 General Recordkeeping Provisions for Specific Situations

The owner or operator must meet all of the applicable recordkeeping requirements of this Section. In accordance with 40 CFR 75.34, incorporated by reference in Section 225.140, the owner or operator of an affected unit with add-on emission controls must record the applicable information in this Section for each hour of missing mercury concentration data. Except as otherwise provided in 40 CFR 75.34(d), incorporated by reference in Section 225.140, for units with add-on mercury emission controls, the owner or operator must record:

- a) Parametric data that demonstrate, for each hour of missing mercury emission data, the proper operation of the add-on emission controls, as described in the quality assurance/quality control program for the unit. The parametric data must be maintained on site and must be submitted, upon request, to the Agency. Alternatively, for units equipped with flue gas desulfurization (FGD) systems, the owner or operator may use quality-assured data from a certified SO₂ monitor to demonstrate proper operation of the emission controls during periods of missing mercury data;

- 5867 b) A flag indicating, for each hour of missing mercury emission data, either that the
5868 add-on emission controls are operating properly, as evidenced by all parameters
5869 being within the ranges specified in the quality assurance/quality control program,
5870 or that the add-on emission controls are not operating properly.
5871

5872 **Section 1.13 Certification, Quality Assurance and Quality Control Record Provisions**
5873

5874 The owner or operator must meet all of the applicable recordkeeping requirements of this
5875 Section.
5876

- 5877 a) Continuous Emission Monitoring Systems. The owner or operator must record the
5878 applicable information in this Section for each certified monitor or certified
5879 monitoring system (including certified backup monitors) measuring and recording
5880 emissions or flow from an affected unit.
5881

- 5882 1) For each flow monitor, mercury monitor or diluent gas monitor (including
5883 wet- and dry-basis O₂ monitors used to determine percent moisture), the
5884 owner or operator must record the following for all daily and 7-day
5885 calibration error tests, all daily system integrity checks and all off-line
5886 calibration demonstrations, including any follow-up tests after corrective
5887 action:
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5889 A) Component-system identification code (on and after January 1,
5890 2009, only the component identification code is required);
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5892 B) Instrument span and span scale;
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5894 C) Date and hour;
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5896 D) Reference value (i.e., calibration gas concentration or reference
5897 signal value, in ppm or other appropriate units);
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5899 E) Observed value (monitor response during calibration, in ppm or
5900 other appropriate units);
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5902 F) Percent calibration error (rounded to the nearest tenth of a percent)
5903 (flag if using alternative performance specification for low emitters
5904 or differential pressure flow monitors);
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5906 G) Reference signal or calibration gas level;
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5908 H) For 7-day calibration error tests, a test number and reason for test;
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- D) For 7-day calibration tests for certification or recertification, a certification from the cylinder gas vendor or CEMS vendor that calibration gas, as defined in 40 CFR 72.2, incorporated by reference in Section 225.140, and Exhibit A to this Appendix, was used to conduct calibration error testing;
 - J) Description of any adjustments, corrective actions or maintenance prior to a passed test or following a failed test; and
 - K) Indication of whether the unit is off-line or on-line.
- 2) For each flow monitor, the owner or operator must record the following for all daily interference checks, including any follow-up tests after corrective action.
- A) Component-system identification code (after January 1, 2009, only the component identification code is required);
 - B) Date and hour;
 - C) Code indicating whether monitor passes or fails the interference check; and
 - D) Description of any adjustments, corrective actions or maintenance prior to a passed test or following a failed test.
- 3) For each mercury concentration monitor or diluent gas monitor (including wet- and dry-basis O₂ monitors used to determine percent moisture), the owner or operator must record the following for the initial and all subsequent linearity checks and 3-level system integrity checks (mercury monitors with converters only), including any follow-up tests after corrective action:
- A) Component-system identification code (on and after July 1, 2009, only the component identification code is required);
 - B) Instrument span and span scale (only span scale is required on and after July 1, 2009);
 - C) Calibration gas level;
 - D) Date and time (hour and minute) of each gas injection at each calibration gas level;

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- E) Reference value (i.e., reference gas concentration for each gas injection at each calibration gas level, in ppm or other appropriate units);
 - F) Observed value (monitor response to each reference gas injection at each calibration gas level, in ppm or other appropriate units);
 - G) Mean of reference values and mean of measured values at each calibration gas level;
 - H) Linearity error at each of the reference gas concentrations (rounded to nearest tenth of a percent) (flag if using alternative performance specification);
 - I) Test number and reason for test (flag if aborted test); and
 - J) Description of any adjustments, corrective action or maintenance prior to a passed test or following a failed test.
- 4) For each differential pressure type flow monitor, the owner or operator must record items in subsections (a)(4)(A) through (E) of this Section, for all quarterly leak checks, including any follow-up tests after corrective action. For each flow monitor, the owner or operator must record items in subsections (a)(4)(F) and (G) of this Section for all flow-to-load ratio and gross heat rate tests:
- A) Component-system identification code (on and after July 1, 2009, only the system identification code is required).
 - B) Date and hour.
 - C) Reason for test.
 - D) Code indicating whether monitor passes or fails the quarterly leak check.
 - E) Description of any adjustments, corrective actions or maintenance prior to a passed test or following a failed test.
 - F) Test data from the flow-to-load ratio or gross heat rate (GHR) evaluation, including:

- 5996 i) Monitoring system identification code;
- 5997
- 5998 ii) Calendar year and quarter;
- 5999
- 6000 iii) Indication of whether the test is a flow-to-load ratio or
- 6001 gross heat rate evaluation;
- 6002
- 6003 iv) Indication of whether bias adjusted flow rates were used;
- 6004
- 6005 v) Average absolute percent difference between reference
- 6006 ratio (or GHR) and hourly ratios (or GHR values);
- 6007
- 6008 vi) Test result;
- 6009
- 6010 vii) Number of hours used in final quarterly average;
- 6011
- 6012 viii) Number of hours exempted for use of a different fuel type;
- 6013
- 6014 ix) Number of hours exempted for load ramping up or down;
- 6015
- 6016 x) Number of hours exempted for scrubber bypass;
- 6017
- 6018 xi) Number of hours exempted for hours preceding a normal-
- 6019 load flow RATA;
- 6020
- 6021 xii) Number of hours exempted for hours preceding a
- 6022 successful diagnostic test, following a documented monitor
- 6023 repair or major component replacement;
- 6024
- 6025 xiii) Number of hours excluded for flue gases discharging
- 6026 simultaneously thorough a main stack and a bypass stack;
- 6027 and
- 6028
- 6029 xiv) Test number.
- 6030
- 6031 G) Reference data for the flow-to-load ratio or gross heat rate
- 6032 evaluation, including (as applicable):
- 6033
- 6034 i) Reference flow RATA end date and time;
- 6035
- 6036 ii) Test number of the reference RATA;
- 6037
- 6038 iii) Reference RATA load and load level;

- 6039
- 6040 iv) Average reference method flow rate during reference flow
- 6041 RATA;
- 6042
- 6043 v) Reference flow/load ratio;
- 6044
- 6045 vi) Average reference method diluent gas concentration during
- 6046 flow RATA and diluent gas units of measure;
- 6047
- 6048 vii) Fuel specific F_d -or F_c -factor during flow RATA and F-
- 6049 factor units of measure;
- 6050
- 6051 viii) Reference gross heat rate value;
- 6052
- 6053 ix) Monitoring system identification code;
- 6054
- 6055 x) Average hourly heat input rate during RATA;
- 6056
- 6057 xi) Average gross unit load;
- 6058
- 6059 xii) Operating load level; and
- 6060
- 6061 xiii) An indicator (flag) if separate reference ratios are
- 6062 calculated for each multiple stack.
- 6063
- 6064 5) For each flow monitor, each diluent gas (O_2 or CO_2) monitor used to
- 6065 determine heat input, each moisture monitoring system, mercury
- 6066 concentration monitoring system, each sorbent trap monitoring system and
- 6067 each approved alternative monitoring system, the owner or operator must
- 6068 record the following information for the initial and all subsequent relative
- 6069 accuracy test audits:
- 6070
- 6071 A) Reference methods used.
- 6072
- 6073 B) Individual test run data from the relative accuracy test audit for the
- 6074 flow monitor, CO_2 emissions concentration monitor-diluent
- 6075 continuous emission monitoring system, diluent gas (O_2 or CO_2)
- 6076 monitor used to determine heat input, moisture monitoring system,
- 6077 mercury concentration monitoring system, sorbent trap monitoring
- 6078 system or approved alternative monitoring system, including:
- 6079
- 6080 i) Date, hour and minute of beginning of test run;
- 6081

- 6082 ii) Date, hour and minute of end of test run;
- 6083
- 6084 iii) Monitoring system identification code;
- 6085
- 6086 iv) Test number and reason for test;
- 6087
- 6088 v) Operating level (low, mid, high or normal, as appropriate)
- 6089 and number of operating levels comprising test;
- 6090
- 6091 vi) Normal load (or operating level) indicator for flow RATAs
- 6092 (except for peaking units);
- 6093
- 6094 vii) Units of measure;
- 6095
- 6096 viii) Run number;
- 6097
- 6098 ix) Run value from CEMS being tested, in the appropriate
- 6099 units of measure;
- 6100
- 6101 x) Run value from reference method, in the appropriate units
- 6102 of measure;
- 6103
- 6104 xi) Flag value (0, 1 or 9, as appropriate) indicating whether run
- 6105 has been used in calculating relative accuracy and bias
- 6106 values or whether the test was aborted prior to completion;
- 6107
- 6108 xii) Average gross unit load, expressed as a total gross unit
- 6109 load, rounded to the nearest MWe, or as steam load,
- 6110 rounded to the nearest 1000 lb/hr, except for units that do
- 6111 not produce electrical or thermal output; and
- 6112
- 6113 xiii) Flag to indicate whether an alternative performance
- 6114 specification has been used.
- 6115
- 6116 C) Calculations and tabulated results, as follows:
- 6117
- 6118 i) Arithmetic mean of the monitoring system measurement
- 6119 values of the reference method values, and of their
- 6120 differences, as specified in Equation A-7 in Exhibit A to
- 6121 this Appendix;
- 6122
- 6123 ii) Standard deviation, as specified in Equation A-8 in Exhibit
- 6124 A to this Appendix;

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- iii) Confidence coefficient, as specified in Equation A–9 in Exhibit A to this Appendix;
 - iv) Statistical t value used in calculations;
 - v) Relative accuracy test results, as specified in Equation A–10 in Exhibit A to this Appendix. For multi-level flow monitor tests the relative accuracy test results must be recorded at each load (or operating) level tested. Each load (or operating) level must be expressed as a total gross unit load, rounded to the nearest MWe, or as steam load, rounded to the nearest 1000 lb/hr, or as otherwise specified by the Agency, for units that do not produce electrical or thermal output;
 - vi) Bias test results as specified in Section 7.4.4 in Exhibit A to this Appendix; and
- D) Description of any adjustment, corrective action or maintenance prior to a passed test or following a failed or aborted test.
 - E) For flow monitors, the equation used to linearize the flow monitor and the numerical values of the polynomial coefficients or K factors of that equation.
 - F) For moisture monitoring systems, the coefficient or K factor or other mathematical algorithm used to adjust the monitoring system with respect to the reference method.
- 6) For each mercury concentration monitor, and each CO₂ or O₂ monitor used to determine heat input, the owner or operator must record the following information for the cycle time test:
- A) Component-system identification code (on and after July 1, 2009, only the component identification code is required);
 - B) Date;
 - C) Start and end times;
 - D) Upscale and downscale cycle times for each component;

- 6168 E) Stable start monitor value;
- 6169
- 6170 F) Stable end monitor value;
- 6171
- 6172 G) Reference value of calibration gases;
- 6173
- 6174 H) Calibration gas level;
- 6175
- 6176 I) Total cycle time;
- 6177
- 6178 J) Reason for test; and
- 6179
- 6180 K) Test number.
- 6181
- 6182 7) In addition to the information in subsection (a)(5) of this Section, the
- 6183 owner or operator must record, for each relative accuracy test audit,
- 6184 supporting information sufficient to substantiate compliance with all
- 6185 applicable Sections and Appendices in this Part. Unless otherwise
- 6186 specified in this Part or in an applicable test method, the information in
- 6187 subsections (a)(7)(A) through (H) of this Section may be recorded either
- 6188 in hard copy format, electronic format or a combination of the two, and
- 6189 the owner or operator must maintain this information in a format suitable
- 6190 for inspection and audit purposes. This RATA supporting information
- 6191 must include, but must not be limited to, the following data elements:
- 6192
- 6193 A) For each RATA using Reference Method 2 (or its allowable
- 6194 alternatives) in appendix A to 40 CFR 60, incorporated by
- 6195 reference in Section 225.140, to determine volumetric flow rate:
- 6196
- 6197 i) Information indicating whether or not the location meets
- 6198 requirements of Method 1 in appendix A to 40 CFR 60,
- 6199 incorporated by reference in Section 225.140; and
- 6200
- 6201 ii) Information indicating whether or not the equipment passed
- 6202 the required leak checks.
- 6203
- 6204 B) For each run of each RATA using Reference Method 2 (or its
- 6205 allowable alternatives in appendix A to 40 CFR 60, incorporated
- 6206 by reference in Section 225.140) to determine volumetric flow
- 6207 rate, record the following data elements (as applicable to the
- 6208 measurement method used):
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- 6210 i) Operating level (low, mid, high or normal, as appropriate);

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- ii) Number of reference method traverse points;
 - iii) Average stack gas temperature (°F);
 - iv) Barometric pressure at test port (inches of mercury);
 - v) Stack static pressure (inches of H₂O);
 - vi) Absolute stack gas pressure (inches of mercury);
 - vii) Percent CO₂ and O₂ in the stack gas, dry basis;
 - viii) CO₂ and O₂ reference method used;
 - ix) Moisture content of stack gas (percent H₂O);
 - x) Molecular weight of stack gas, dry-basis (lb/lb-mole);
 - xi) Molecular weight of stack gas, wet-basis (lb/lb-mole);
 - xii) Stack diameter (or equivalent diameter) at the test port (ft);
 - xiii) Average square root of velocity head of stack gas (inches of H₂O) for the run;
 - xiv) Stack or duct cross-sectional area at test port (ft²);
 - xv) Average velocity (ft/sec);
 - xvi) Average stack flow rate, adjusted, if applicable, for wall effects (scfh, wet-basis);
 - xvii) Flow rate reference method used;
 - xviii) Average velocity, adjusted for wall effects;
 - xix) Calculated (site-specific) wall effects adjustment factor determined during the run, and, if different, the wall effects adjustment factor used in the calculations; and
 - xx) Default wall effects adjustment factor used.

- 6254 C) For each traverse point of each run of each RATA using Reference
 6255 Method 2 (or its allowable alternatives in appendix A to 40 CFR
 6256 60, incorporated by reference in Section 225.140) to determine
 6257 volumetric flow rate, record the following data elements (as
 6258 applicable to the measurement method used):
 6259
 6260 i) Reference method probe type;
 6261
 6262 ii) Pressure measurement device type;
 6263
 6264 iii) Traverse point ID;
 6265
 6266 iv) Probe or pitot tube calibration coefficient;
 6267
 6268 v) Date of latest probe or pitot tube calibration;
 6269
 6270 vi) Average velocity differential pressure at traverse point
 6271 (inches of H₂O) or the average of the square roots of the
 6272 velocity differential pressures at the traverse point ((inches
 6273 of H₂O)^{1/2});
 6274
 6275 vii) T_s, stack temperature at the traverse point (°F);
 6276
 6277 viii) Composite (wall effects) traverse point identifier;
 6278
 6279 ix) Number of points included in composite traverse point;
 6280
 6281 x) Yaw angle of flow at traverse point (degrees);
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 6283 xi) Pitch angle of flow at traverse point (degrees);
 6284
 6285 xii) Calculated velocity at traverse point both accounting and
 6286 not accounting for wall effects (ft/sec); and
 6287
 6288 xiii) Probe identification number.
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 6290 D) For each RATA using Method 3A in appendix A to 40 CFR 60,
 6291 incorporated by reference in Section 225.140, to determine CO₂, or
 6292 O₂ concentration:
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 6294 i) Pollutant or diluent gas being measured;
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 6296 ii) Span of reference method analyzer;

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- iii) Type of reference method system (e.g., extractive or dilution type);
 - iv) Reference method dilution factor (dilution type systems only);
 - v) Reference gas concentrations (zero, mid and high gas levels) used for the 3-point pre-test analyzer calibration error test (or, for dilution type reference method systems, for the 3-point pre-test system calibration error test) and for any subsequent recalibrations;
 - vi) Analyzer responses to the zero-, mid- and high-level calibration gases during the 3-point pre-test analyzer (or system) calibration error test and during any subsequent recalibrations;
 - vii) Analyzer calibration error at each gas level (zero, mid and high) for the 3-point pre-test analyzer (or system) calibration error test and for any subsequent recalibrations (percent of span value);
 - viii) Upscale gas concentration (mid or high gas level) used for each pre-run or post-run system bias check or (for dilution type reference method systems) for each pre-run or post-run system calibration error check;
 - ix) Analyzer response to the calibration gas for each pre-run or post-run system bias (or system calibration error) check;
 - x) The arithmetic average of the analyzer responses to the zero-level gas, for each pair of pre- and post-run system bias (or system calibration error) checks;
 - xi) The arithmetic average of the analyzer responses to the upscale calibration gas for each pair of pre- and post-run system bias (or system calibration error) checks;
 - xii) The results of each pre-run and each post-run system bias (or system calibration error) check using the zero-level gas (percentage of span value);

- 6340 xiii) The results of each pre-run and each post-run system bias
- 6341 (or system calibration error) check using the upscale
- 6342 calibration gas (percentage of span value);
- 6343
- 6344 xiv) Calibration drift and zero drift of analyzer during each
- 6345 RATA run (percentage of span value);
- 6346
- 6347 xv) Moisture basis of the reference method analysis;
- 6348
- 6349 xvi) Moisture content of stack gas, in percent, during each test
- 6350 run (if needed to convert to moisture basis of CEMS being
- 6351 tested);
- 6352
- 6353 xvii) Unadjusted (raw) average pollutant or diluent gas
- 6354 concentration for each run;
- 6355
- 6356 xviii) Average pollutant or diluent gas concentration for each run,
- 6357 corrected for calibration bias (or calibration error) and, if
- 6358 applicable, corrected for moisture;
- 6359
- 6360 xix) The F-factor used to convert reference method data to units
- 6361 of lb/mmBtu (if applicable);
- 6362
- 6363 xx) Dates of the latest analyzer interference tests;
- 6364
- 6365 xxi) Results of the latest analyzer interference tests; and
- 6366
- 6367 xxii) For each calibration gas cylinder used during each RATA,
- 6368 record the cylinder gas vendor, cylinder number, expiration
- 6369 date, pollutants in the cylinder and certified gas
- 6370 concentrations.
- 6371
- 6372 E) For each test run of each moisture determination using Method 4 in
- 6373 appendix A to 40 CFR 60, incorporated by reference in Section
- 6374 225.140, (or its allowable alternatives), whether the determination
- 6375 is made to support a gas RATA, to support a flow RATA or to
- 6376 quality assure the data from a continuous moisture monitoring
- 6377 system, record the following data elements (as applicable to the
- 6378 moisture measurement method used):
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- 6380 i) Test number;
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- 6382 ii) Run number;

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- iii) The beginning date, hour and minute of the run;
 - iv) The ending date, hour and minute of the run;
 - v) Unit operating level (low, mid, high or normal, as appropriate);
 - vi) Moisture measurement method;
 - vii) Volume of H₂O collected in the impingers (ml);
 - viii) Mass of H₂O collected in the silica gel (g);
 - ix) Dry gas meter calibration factor;
 - x) Average dry gas meter temperature (°F);
 - xi) Barometric pressure (inches of mercury);
 - xii) Differential pressure across the orifice meter (inches of H₂O);
 - xiii) Initial and final dry gas meter readings (ft³);
 - xiv) Total sample gas volume, corrected to standard conditions (dscf); and
 - xv) Percentage of moisture in the stack gas (percent H₂O).
- F) The raw data and calculated results for any stratification tests performed in accordance with Sections 6.5.5.1 through 6.5.5.3 of Exhibit A to this Appendix.
 - G) For each RATA run using the Ontario Hydro Method to determine mercury concentration:
 - i) Percent CO₂ and O₂ in the stack gas, dry-basis;
 - ii) Moisture content of the stack gas (percent H₂O);
 - iii) Average stack temperature (°F);

- 6426 iv) Dry gas volume metered (dscm);
- 6427
- 6428 v) Percent isokinetic;
- 6429
- 6430 vi) Particle-bound mercury collected by the filter, blank and
- 6431 probe rinse (µgm);
- 6432
- 6433 vii) Oxidized mercury collected by the KCl impingers (µgm);
- 6434
- 6435 viii) Elemental mercury collected in the HNO₃/H₂O₂ impinger
- 6436 and in the KMnO₄/H₂SO₄ impingers (µgm);
- 6437
- 6438 ix) Total mercury, including particle-bound mercury (µgm);
- 6439 and
- 6440
- 6441 x) Total mercury, excluding particle-bound mercury (µgm)
- 6442
- 6443 H) All appropriate data elements for Methods 30A and 30B.
- 6444
- 6445 I) For a unit with a flow monitor installed on a rectangular stack or
- 6446 duct, if a site-specific default or measured wall effects adjustment
- 6447 factor (WAF) is used to correct the stack gas volumetric flow rate
- 6448 data to account for velocity decay near the stack or duct wall, the
- 6449 owner or operator must keep records of the following for each flow
- 6450 RATA performed with EPA Method 2 in appendices A-1 and A-2
- 6451 to 40 CFR 60, incorporated by reference in Section 225.140,
- 6452 subsequent to the WAF determination:
- 6453
- 6454 i) Monitoring system ID;
- 6455
- 6456 ii) Test number;
- 6457
- 6458 iii) Operating level;
- 6459
- 6460 iv) RATA end date and time;
- 6461
- 6462 v) Number of Method 1 traverse points; and
- 6463
- 6464 vi) Wall effects adjustment factor (WAF), to the nearest
- 6465 0.0001.
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- J) For each RATA run using Method 29 in appendix A-8 to 40 CFR 60, incorporated by reference in Section 225.140, to determine mercury concentration:
 - i) Percent CO₂ and O₂ in the stack gas, dry-basis;
 - ii) Moisture content of the stack gas (percent H₂O);
 - iii) Average stack gas temperature (°F);
 - iv) Dry gas volume metered (dscm);
 - v) Percent isokinetic;
 - vi) Particulate mercury collected in the front half of the sampling train, corrected for the front-half blank value (µgm); and
 - vii) Total vapor phase mercury collected in the back half of the sampling train, corrected for the back-half blank value (µgm).

- 8) For each certified continuous emission monitoring system, excepted monitoring system or alternative monitoring system, the date and description of each event that requires certification, recertification or certain diagnostic testing of the system and the date and type of each test performed. If the conditional data validation procedures of Section 1.4(b)(3) of this Appendix are to be used to validate and report data prior to the completion of the required certification, recertification or diagnostic testing, the date and hour of the probationary calibration error test must be reported to mark the beginning of conditional data validation.

- 9) Hardcopy relative accuracy test reports, certification reports, recertification reports or semiannual or annual reports for gas or flow rate CEMS, mercury CEMS or sorbent trap monitoring systems are required or requested under 40 CFR 75.60(b)(6) or 75.63, incorporated by reference in Section 225.140, the reports must include, at a minimum, the following elements as applicable to the types of tests performed:
 - A) Summarized test results.
 - B) DAHS printouts of the CEMS data generated during the calibration error, linearity, cycle time and relative accuracy tests.

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- C) For pollutant concentration monitor or diluent monitor relative accuracy tests at normal operating load:
- i) The raw reference method data from each run, i.e., the data under subsection (a)(7)(D)(xvii) of this Section (usually in the form of a computerized printout, showing a series of one-minute readings and the run average);
 - ii) The raw data and results for all required pre-test, post-test, pre-run and post-run quality assurance checks (i.e., calibration gas injections) of the reference method analyzers, i.e., the data under subsections (a)(7)(D)(v) through (xiv) of this Section;
 - iii) The raw data and results for any moisture measurements made during the relative accuracy testing, i.e., the data under subsections (a)(7)(E)(i) through (xv) of this Section; and
 - iv) Tabulated, final, corrected reference method run data (i.e., the actual values used in the relative accuracy calculations), along with the equations used to convert the raw data to the final values and example calculations to demonstrate how the test data were reduced.
- D) For relative accuracy tests for flow monitors:
- i) The raw flow rate reference method data, from Reference Method 2 (or its allowable alternatives) under appendix A to 40 CFR 60, incorporated by reference in Section 225.140, including auxiliary moisture data (often in the form of handwritten data sheets), i.e., the data under subsections (a)(7)(B)(i) through (xx), subsections (a)(7)(C)(i) through (xiii), and, if applicable, subsections (a)(7)(E)(i) through (xv) of this Section; and
 - ii) The tabulated, final volumetric flow rate values used in the relative accuracy calculations (determined from the flow rate reference method data and other necessary measurements, such as moisture, stack temperature and pressure), along with the equations used to convert the raw

- 6552 data to the final values and example calculations to
6553 demonstrate how the test data were reduced.
6554
6555 E) Calibration gas certificates for the gases used in the linearity,
6556 calibration error and cycle time tests and for the calibration gases
6557 used to quality assure the gas monitor reference method data
6558 during the relative accuracy test audit.
6559
6560 F) Laboratory calibrations of the source sampling equipment. For
6561 sorbent trap monitoring systems, the laboratory analyses of all
6562 sorbent traps and information documenting the results of all leak
6563 checks and other applicable quality control procedures.
6564
6565 G) A copy of the test protocol used for the CEMS certifications or
6566 recertifications, including narrative that explains any testing
6567 abnormalities, problematic sampling, and analytical conditions that
6568 required a change to the test protocol, and/or solutions to technical
6569 problems encountered during the testing program.
6570
6571 H) Diagrams illustrating test locations and sample point locations (to
6572 verify that locations are consistent with information in the
6573 monitoring plan). Include a discussion of any special traversing or
6574 measurement scheme. The discussion must also confirm that
6575 sample points satisfy applicable acceptance criteria.
6576
6577 I) Names of key personnel involved in the test program, including
6578 test team members, plant contacts, agency representatives and test
6579 observers on site.
6580
6581 10) Whenever reference methods are used as backup monitoring systems
6582 pursuant to Section 1.4(d)(3) of this Appendix, the owner or operator must
6583 record the following information:
6584
6585 A) For each test run using Reference Method 2 (or its allowable
6586 alternatives in appendix A to 40 CFR 60, incorporated by reference
6587 in Section 225.140) to determine volumetric flow rate, record the
6588 following data elements (as applicable to the measurement method
6589 used):
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6591 i) Unit or stack identification number;
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6593 ii) Reference method system and component identification
6594 numbers;

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- iii) Run date and hour;
 - iv) The data in subsection (a)(7)(B) of this Section, except for subsections (a)(7)(B)(i), (vi), (viii), (xii) and (xvii) through (xx); and
 - v) The data in subsection (a)(7)(C), except on a run basis.
- B) For each reference method test run using Method 6C, 7E or 3A in appendix A to 40 CFR 60, incorporated by reference in Section 225.140, to determine SO₂, NO_x, CO₂ or O₂ concentration:
- i) Unit or stack identification number;
 - ii) The reference method system and component identification numbers;
 - iii) Run number;
 - iv) Run start date and hour;
 - v) Run end date and hour;
 - vi) The data in subsections (a)(7)(D)(ii) through (ix) and (xii) through (xv); and (vii) Stack gas density adjustment factor (if applicable).
- C) For each hour of each reference method test run using Method 6C, 7E or 3A in appendix A to 40 CFR 60, incorporated by reference in Section 225.140, to determine SO₂, NO_x, CO₂, or O₂ concentration:
- i) Unit or stack identification number;
 - ii) The reference method system and component identification numbers;
 - iii) Run number;
 - iv) Run date and hour;
 - v) Pollutant or diluent gas being measured;

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- vi) Unadjusted (raw) average pollutant or diluent gas concentration for the hour; and
 - vii) Average pollutant or diluent gas concentration for the hour, adjusted as appropriate for moisture, calibration bias (or calibration error) and stack gas density.

11) For each other quality-assurance test or other quality assurance activity, the owner or operator must record the following (as applicable):

- A) Component/system identification code;
- B) Parameter;
- C) Test or activity completion date and hour;
- D) Test or activity description;
- E) Test result;
- F) Reason for test; and
- G) Test code.

12) For each request for a quality assurance test extension or exemption, for any loss of exempt status, and for each single-load flow RATA claim pursuant to Section 2.3.1.3(c)(3) of Exhibit B to this Appendix, the owner or operator must record the following (as applicable):

- A) For a RATA deadline extension or exemption request:
 - i) Monitoring system identification code;
 - ii) Date of last RATA;
 - iii) RATA expiration date without extension;
 - iv) RATA expiration date with extension;
 - v) Type of RATA extension of exemption claimed or lost;

- 6680 vi) Year to date hours of usage of fuel other than very low
6681 sulfur fuel;
6682
6683 vii) Year to date hours of non-redundant back-up CEMS usage
6684 at the unit/stack; and
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6686 viii) Quarter and year.
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6688 B) For a linearity test or flow-to-load ratio test quarterly exemption:
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6690 i) Component-system identification code;
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6692 ii) Type of test;
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6694 iii) Basis for exemption;
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6696 iv) Quarter and year; and
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6698 v) Span scale.
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6700 C) For a fuel flowmeter accuracy test extension:
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6702 i) Component-system identification code;
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6704 ii) Date of last accuracy test;
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6706 iii) Accuracy test expiration date without extension;
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6708 iv) Accuracy test expiration date with extension;
6709
6710 v) Type of extension; and
6711
6712 vi) Quarter and year.
6713
6714 D) For a single-load (or single-level) flow RATA claim:
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6716 i) Monitoring system identification code;
6717
6718 ii) Ending date of last annual flow RATA;
6719
6720 iii) The relative frequency (percentage) of unit or stack
6721 operation at each load (or operating) level (low, mid and

- 6722 high) since the previous annual flow RATA, to the nearest
6723 0.1 percent;
6724
6725 iv) End date of the historical load (or operating level) data
6726 collection period; and
6727
6728 v) Indication of the load (or operating) level (low, mid or
6729 high) claimed for the single-load flow RATA.
6730
6731 13) For the sorbent traps used in sorbent trap monitoring systems to quantify
6732 mercury concentration under Sections 1.14 through 1.18 of this Appendix
6733 (including sorbent traps used for relative accuracy testing), the owner or
6734 operator must keep records of the following:
6735
6736 A) The ID number of the monitoring system in which each sorbent
6737 trap was used to collect mercury;
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6739 B) The unique identification number of each sorbent trap;
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6741 C) The beginning and ending dates and hours of the data collection
6742 period for each sorbent trap;
6743
6744 D) The average mercury concentration (in $\mu\text{gm}/\text{dscm}$) for the data
6745 collection period;
6746
6747 E) Information documenting the results of the required leak checks;
6748
6749 F) The analysis of the mercury collected by each sorbent trap; and
6750
6751 G) Information documenting the results of the other applicable quality
6752 control procedures in Section 1.3 of this Appendix and in Exhibits
6753 B and D to this Appendix.
6754
6755 b) Except as otherwise provided in Section 1.12(a) of this Appendix, for units with
6756 add-on mercury emission controls, the owner or operator must keep the following
6757 records on-site in the quality assurance/quality control plan required by Section 1
6758 of Exhibit B to this Appendix:
6759
6760 1) A list of operating parameters for the add-on emission controls, including
6761 parameters in Section 1.12 of this Appendix, appropriate to the particular
6762 installation of add-on emission controls; and
6763

- 6764 2) The range of each operating parameter in the list that indicates the add-on
 6765 emission controls are properly operating.
- 6766
- 6767 c) Excepted Monitoring for Mercury Low Mass Emission Units under Section
 6768 1.15(b) of this Appendix. For qualifying coal-fired units using the alternative low
 6769 mass emission methodology under Section 1.15(b), the owner or operator must
 6770 record the data elements described in Section 1.13(a)(7)(G), Section 1.13(a)(7)(H)
 6771 or Section 1.13(a)(7)(J) of this Appendix, as applicable, for each run of each
 6772 mercury emission test and re-test required under Section 1.15(c)(1) or Section
 6773 1.15(d)(4)(C) of this Appendix.
- 6774
- 6775 d) DAHS Verification. For each DAHS (missing data and formula) verification that
 6776 is required for initial certification, recertification or for certain diagnostic testing
 6777 of a monitoring system, record the date and hour that the DAHS verification is
 6778 successfully completed. (This requirement only applies to units that report
 6779 monitoring plan data in accordance with Section 1.10(d) of this Appendix.)

6780

6781 **Section 1.14 General Provisions**

6782

- 6783 a) Applicability. The owner or operator of a unit must comply with the requirements
 6784 of this Appendix to the extent that compliance is required by this Part. For
 6785 purposes of this Appendix, the term "affected unit" means any coal-fired unit (as
 6786 defined in 40 CFR 72.2, incorporated by reference) that is subject to this Part. The
 6787 term "non-affected unit" means any unit that is not subject to such a program, the
 6788 term "permitting authority" means the Agency, and the term "designated
 6789 representative" means the responsible party under this Part.
- 6790
- 6791 b) Compliance Dates. The owner or operator of an affected unit must meet the
 6792 compliance deadlines established by Subpart B of this Part.
- 6793
- 6794 c) Prohibitions.
- 6795
- 6796 1) No owner or operator of an affected unit or a non-affected unit under
 6797 Section 1.16(b)(2)(B) of this Appendix will use any alternative monitoring
 6798 system, alternative reference method or any other alternative for the
 6799 required continuous emission monitoring system without having obtained
 6800 prior written approval in accordance with subsection (f) of this Section.
- 6801
- 6802 2) No owner or operator of an affected unit or a non-affected unit under
 6803 Section 1.16(b)(2)(B) of this Appendix will operate the unit so as to
 6804 discharge, or allow to be discharged, emissions of mercury to the
 6805 atmosphere without accounting for all such emissions in accordance with
 6806 the applicable provisions of this Appendix.

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- 3) No owner or operator of an affected unit or a non-affected unit under Section 1.16(b)(2)(B) of this Appendix will disrupt the continuous emission monitoring system, any portion of the system, or any other approved emission monitoring method, and thereby avoid monitoring and recording mercury mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing or maintenance is performed in accordance with the provisions of this Appendix applicable to monitoring systems under Section 1.15 of this Appendix.

- 4) No owner or operator of an affected unit or a non-affected unit under Section 1.16(b)(2)(B) will retire or permanently discontinue use of the continuous emission monitoring system, any component of the system, or any other approved emission monitoring system under this Appendix, except under any one of the following circumstances:
 - A) During the period that the unit is covered by a retired unit exemption that is in effect under this Part; or

 - B) The owner or operator is monitoring mercury mass emissions from the affected unit with another certified monitoring system approved, in accordance with the provisions of Section 250 of this Part; or

 - C) The designated representative submits notification of the date of certification testing of a replacement monitoring system in accordance with Section 240(d) of this Part.

- d) Quality Assurance and Quality Control Requirements. For units that use continuous emission monitoring systems to account for mercury mass emissions, the owner or operator must meet the applicable quality assurance and quality control requirements in Section 1.5 and Exhibit B to this Appendix for the flow monitoring systems, mercury concentration monitoring systems, moisture monitoring systems and diluent monitors required under Section 1.15 of this Appendix. Units using sorbent trap monitoring systems must meet the applicable quality assurance requirements in Section 1.3 of this Appendix, Exhibit D to this Appendix, and Sections 1.3 and 2.3 of Exhibit B to this Appendix.

- e) Reporting Data Prior to Initial Certification. If, by the applicable compliance date under this Part, the owner or operator of an affected unit has not successfully completed all required certification tests for any monitoring systems, he or she must determine, record, and report data prior to initial certification in accordance

6850 with Section 239 of this Part.

6851

6852 f) Petitions.

6853

6854 1) The designated representative of an affected unit that is also subject to the
 6855 Acid Rain Program may submit a petition to the Agency requesting an
 6856 alternative to any requirement of Sections 1.14 through 1.18 of this
 6857 Appendix. Such a petition must meet the requirements of 40 CFR 75.66,
 6858 incorporated by reference in Section 225.140, and any additional
 6859 requirements established by Subpart B of this Part. Use of an alternative to
 6860 any requirement of Sections 1.14 through 1.18 of this Appendix is in
 6861 accordance with Sections 1.14 through 1.18 of this Appendix and with
 6862 Subpart B of this Part only to the extent that the petition is approved in
 6863 writing by the Agency.

6864

6865 2) Notwithstanding subsection (f)(1) of this Section, petitions requesting an
 6866 alternative to a requirement concerning any additional CEMS required
 6867 solely to meet the common stack provisions of Section 1.16 of this
 6868 Appendix must be submitted to the Agency and will be governed by
 6869 subsection (f)(3) of this Section. Such a petition must meet the
 6870 requirements of 40 CFR 75.66, incorporated by reference in Section
 6871 225.140, and any additional requirements established by Subpart B of this
 6872 Part.

6873

6874 3) The designated representative of an affected unit that is not subject to the
 6875 Acid Rain Program may submit a petition to the Agency requesting an
 6876 alternative to any requirement of Sections 1.14 through 1.18 of this
 6877 Appendix. Such a petition must meet the requirements of 40 CFR 75.66,
 6878 incorporated by reference in Section 225.140, and any additional
 6879 requirements established by Subpart B of this Part. Use of an alternative to
 6880 any requirement of Sections 1.14 through 1.18 of this Appendix is in
 6881 accordance with Sections 1.14 through 1.18 of this Appendix only to the
 6882 extent that it is approved in writing by the Agency.

6883

6884 **Section 1.15 Monitoring of Mercury Mass Emissions and Heat Input at the Unit Level**

6885

6886 The owner or operator of the affected coal-fired unit must:

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6888 a) Meet the general operating requirements in Section 1.2 of this Appendix for the
 6889 following continuous emission monitors (except as provided in accordance with
 6890 subpart E of 40 CFR 75, incorporated by reference in Section 225.140):

6891

6892 1) A mercury concentration monitoring system (consisting of a mercury

6893 pollutant concentration monitor and an automated DAHS, which provides
 6894 a permanent, continuous record of mercury emissions in units of
 6895 micrograms per standard cubic meter ($\mu\text{g}/\text{scm}$)) or a sorbent trap
 6896 monitoring system to measure the mass concentration of total vapor phase
 6897 mercury in the flue gas, including the elemental and oxidized forms of
 6898 mercury, in micrograms per standard cubic meter ($\mu\text{g}/\text{scm}$);

6900 2) A flow monitoring system;

6901
 6902 3) A continuous moisture monitoring system (if correction of mercury
 6903 concentration for moisture is required), as described in 40 CFR 75.11(b),
 6904 incorporated by reference in Section 225.140. Alternatively, the owner or
 6905 operator may use the appropriate fuel-specific default moisture value
 6906 provided in 40 CFR 75.11, incorporated by reference in Section 225.140,
 6907 or a site-specific moisture value approved by petition under 40 CFR 75.66,
 6908 incorporated by reference in Section 225.140; and

6909
 6910 4) If heat input is required to be reported under this Part, the owner or
 6911 operator must meet the general operating requirements for a flow
 6912 monitoring system and an O₂ or CO₂ monitoring system to measure heat
 6913 input rate.

6914
 6915 b) For an affected unit that emits 464 ounces (29 lb) of mercury per year or less, use
 6916 the following excepted monitoring methodology. To implement this methodology
 6917 for a qualifying unit, the owner or operator must meet the general operating
 6918 requirements in Section 1.2 of this Appendix for the continuous emission
 6919 monitors described in subsections (a)(2) and (a)(4) of this Section, and perform
 6920 mercury emission testing for initial certification and on-going quality-assurance,
 6921 as described in subsections (c) through (e) of this Section.

6922
 6923 c) To determine whether an affected unit is eligible to use the monitoring provisions
 6924 in subsections (b) of this Section:

6925
 6926 1) The owner or operator must perform mercury emission testing within 18
 6927 months before the compliance date in Section 1.14(b) of this Appendix to
 6928 determine the mercury concentration (i.e., total vapor phase mercury) in
 6929 the effluent.

6930
 6931 A) The testing must be performed using one of the mercury reference
 6932 methods listed in Section 1.6(a)(5) of this Appendix, and must
 6933 consist of a minimum of 3 runs at the normal unit operating load,
 6934 while combusting coal. The coal combusted during the testing
 6935 must be representative of the coal that will be combusted at the

start of the mercury mass emissions reduction program (preferably from the same sources of supply).

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B) The minimum time per run must be 1 hour if Method 30A is used. If either Method 29 in appendix A-8 to 40 CFR 60, incorporated by reference, ASTM D6784-02 (the Ontario Hydro method) (incorporated by reference under Section 225.140) or Method 30B is used, paired samples are required for each test run and the runs must be long enough to ensure that sufficient mercury is collected to analyze. When Method 29 in appendix A-8 to 40 CFR 60, incorporated by reference, or the Ontario Hydro method is used, the test results must be based on the vapor phase mercury collected in the back-half of the sampling trains (i.e., the non-filterable impinger catches). For each Method 29 in appendix A-8 to 40 CFR 60, incorporated by reference, Method 30B or Ontario Hydro method test run, the paired trains must meet the relative deviation (RD) requirement specified in Section 1.6(a)(5) of this Appendix or Method 30B, as applicable. If the RD specification is met, the results of the two samples must be averaged arithmetically.

C) If the unit is equipped with flue gas desulfurization or add-on mercury emission controls, the controls must be operating normally during the testing, and, for the purpose of establishing proper operation of the controls, the owner or operator must record parametric data or SO₂ concentration data in accordance with Section 1.12(a) of this Appendix.

D) If two or more of units of the same type qualify as a group of identical units in accordance with 40 CFR 75.19(c)(1)(iv)(B), incorporated by reference in Section 225.140, the owner or operator may test a subset of these units in lieu of testing each unit individually. If this option is selected, the number of units required to be tested must be determined from Table LM-4 in 40 CFR 75.19, incorporated by reference in Section 225.140. For the purposes of the required retests under subsection (d)(4) of this Section, it is strongly recommended that (to the extent practicable) the same subset of the units not be tested in two successive retests, and that every effort be made to ensure that each unit in the group of identical units is tested in a timely manner.

2)

A) Based on the results of the emission testing, Equation 1 of this

6979 Section must be used to provide a conservative estimate of the
 6980 annual mercury mass emissions from the unit:

6981

6982
$$E = N \times K \times C_{Hg} \times Q_{max} \quad \text{(Equation 1)}$$

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6985

Where:

- E ≡ Estimated annual mercury mass emissions from the affected unit, (ounces/year)
- K ≡ Units conversion constant, 9.978×10^{-10} oz-scm/ μ g-scf
- N ≡ Either 8,760 (the number of hours in a year) or the maximum number of operating hours per year (if less than 8,760) allowed by the unit's Federally-enforceable operating permit.
- C_{Hg} ≡ The highest mercury concentration (μ g/scm) from any of the test runs or 0.50 μ g/scm, whichever is greater
- Q_{max} ≡ Maximum potential flow rate, determined according to Section 2.1.2.1 of Exhibit A to this Appendix, (scfh)

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B) Equation 1 of this Section assumes that the unit operates at its maximum potential flow rate, either year-round or for the maximum number of hours allowed by the operating permit (if unit operation is restricted to less than 8,760 hours per year). If the permit restricts the annual unit heat input but not the number of annual unit operating hours, the owner or operator may divide the allowable annual heat input (mmBtu) by the design rated heat input capacity of the unit (mmBtu/hr) to determine the value of "N" in Equation 1. Also, note that if the highest mercury concentration measured in any test run is less than 0.50 μ g/scm, a default value of 0.50 μ g/scm must be used in the calculations.

3) If the estimated annual mercury mass emissions from subsection (c)(2) of this Section are 464 ounces per year or less, then the unit is eligible to use the monitoring provisions in subsection (b) of this Section, and continuous monitoring of the mercury concentration is not required (except as otherwise provided in subsections (e) and (f) of this Section).

d) If the owner or operator of an eligible unit under subsection (c)(3) of this Section elects not to continuously monitor mercury concentration, then the following requirements must be met:

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- 1) The results of the mercury emission testing performed under subsection (c) of this Section must be submitted as a certification application to the permitting authority, no later than 45 days after the testing is completed. The calculations demonstrating that the unit emits 464 ounces (or less) per year of mercury must also be provided, and the default mercury concentration that will be used for reporting under Section 1.18 of this Appendix must be specified in both the electronic and hard copy portions of the monitoring plan for the unit. The methodology is considered to be provisionally certified as of the date and hour of completion of the mercury emission testing.

- 2) Following initial certification, the same default mercury concentration value that was used to estimate the unit's annual mercury mass emissions under subsection (c) of this Section must be reported for each unit operating hour, except as otherwise provided in subsection (d)(4)(D) or (d)(6) of this Section. The default mercury concentration value must be updated as appropriate according to subsection (d)(5) of this Section.

- 3) The hourly mercury mass emissions must be calculated according to Section 4.1.3 in Exhibit C to this Appendix.

- 4) The mercury emission testing described in subsection (c) of this Section must be repeated periodically, for the purposes of quality-assurance, as follows:
 - A) If the results of the certification testing under subsection (c) of this Section show that the unit emits 144 ounces (9 lb) of mercury per year or less, the first retest is required by the end of the fourth QA operating quarter (as defined in 40 CFR 72.2, incorporated by reference) following the calendar quarter of the certification testing; or

 - B) If the results of the certification testing under subsection (c) of this Section show that the unit emits more than 144 ounces of mercury per year, but less than or equal to 464 ounces per year, the first retest is required by the end of the second QA operating quarter (as defined in 40 CFR 72.2, incorporated by reference) following the calendar quarter of the certification testing; and

 - C) Thereafter, retesting must be required either semiannually or annually (i.e., by the end of the second or fourth QA operating quarter following the quarter of the previous test), depending on

7051 the results of the previous test. To determine whether the next
 7052 retest is due within two or four QA operating quarters, substitute
 7053 the highest mercury concentration from the current test or 0.50
 7054 µg/scm (whichever is greater) into the equation in subsection (c)(2)
 7055 of this Section. If the estimated annual mercury mass emissions
 7056 exceeds 144 ounces, the next test is due within two QA operating
 7057 quarters. If the estimated annual mercury mass emissions is 144
 7058 ounces or less, the next test is due within four QA operating
 7059 quarters.

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 7061 D) An additional retest is required when there is a change in the coal
 7062 rank of the primary fuel (e.g., when the primary fuel is switched
 7063 from bituminous coal to lignite). Use ASTM D388-99
 7064 (incorporated by reference under Section 225.140) to determine the
 7065 coal rank. The four principal coal ranks are anthracitic, bituminous,
 7066 subbituminous and lignitic. The ranks of anthracite coal refuse
 7067 (culm) and bituminous coal refuse (gob) must be anthracitic and
 7068 bituminous, respectively. The retest must be performed within 720
 7069 unit operating hours of the change.

7070
 7071 5) The default mercury concentration used for reporting under Section 1.18
 7072 of this Appendix must be updated after each required retest. This includes
 7073 retests that are required prior to the compliance date in Section 1.14(b) of
 7074 this Appendix. The updated value must either be the highest mercury
 7075 concentration measured in any of the test runs or 0.50 µg/scm, whichever
 7076 is greater. The updated value must be applied beginning with the first unit
 7077 operating hour in which mercury emissions data are required to be
 7078 reported after completion of the retest, except as provided in subsection
 7079 (d)(4)(D) of this Section, where the need to retest is triggered by a change
 7080 in the coal rank of the primary fuel. In that case, apply the updated default
 7081 mercury concentration beginning with the first unit operating hour in
 7082 which mercury emissions are required to be reported after the date and
 7083 hour of the fuel switch.

7084
 7085 6) If the unit is equipped with a flue gas desulfurization system or add-on
 7086 mercury controls, the owner or operator must record the information
 7087 required under Section 1.12 of this Appendix for each unit operating hour,
 7088 to document proper operation of the emission controls.

7089
 7090 e) For units with common stack and multiple stack exhaust configurations, the use of
 7091 the monitoring methodology described in subsections (b) through (d) of this
 7092 Section is restricted as follows:
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- 1) The methodology may not be used for reporting mercury mass emissions at a common stack unless all of the units using the common stack are affected units and the units' combined potential to emit does not exceed 464 ounces of mercury per year times the number of units sharing the stack, in accordance with subsections (c) and (d) of this Section. If the test results demonstrate that the units sharing the common stack qualify as low mass emitters, the default mercury concentration used for reporting mercury mass emissions at the common stack must either be the highest value obtained in any test run or 0.50 $\mu\text{g}/\text{scm}$, whichever is greater.
 - A) The initial emission testing required under subsection (c) of this Section may be performed at the common stack if the following conditions are met. Otherwise, testing of the individual units (or a subset of the units, if identical, as described in subsection (c)(1)(D) of this Section) is required:
 - i) The testing must be done at a combined load corresponding to the designated normal load level (low, mid or high) for the units sharing the common stack in accordance with Section 6.5.2.1 of Exhibit A to this Appendix;
 - ii) All of the units that share the stack must be operating in a normal, stable manner and at typical load levels during the emission testing. The coal combusted in each unit during the testing must be representative of the coal that will be combusted in that unit at the start of the mercury mass emission reduction program (preferably from the same sources of supply);
 - iii) If flue gas desulfurization and/or add-on mercury emission controls are used to reduce the level of the emissions exiting from the common stack, these emission controls must be operating normally during the emission testing and, for the purpose of establishing proper operation of the controls, the owner or operator must record parametric data or SO_2 concentration data in accordance with Section 1.12(a) of this Appendix;
 - iv) When calculating E, the estimated maximum potential annual mercury mass emissions from the stack, substitute the maximum potential flow rate through the common stack (as defined in the monitoring plan) and the highest concentration from any test run (or 0.50 $\mu\text{g}/\text{scm}$, if greater)

into Equation 1;

- v) The calculated value of E must be divided by the number of units sharing the stack. If the result, when rounded to the nearest ounce, does not exceed 464 ounces, the units qualify to use the low mass emission methodology; and
- vi) If the units qualify to use the methodology, the default mercury concentration used for reporting at the common stack must be the highest value obtained in any test run or 0.50 µg/scm, whichever is greater; or

B) The retests required under subsection (d)(4) of this Section may also be done at the common stack. If this testing option is chosen, the testing must be done at a combined load corresponding to the designated normal load level (low, mid or high) for the units sharing the common stack, in accordance with Section 6.5.2.1 of Exhibit A to this Appendix. Provided that the required load level is attained and that all of the units sharing the stack are fed from the same on-site coal supply during normal operation, it is not necessary for all of the units sharing the stack to be in operation during a retest. However, if two or more of the units that share the stack are fed from different on-site coal supplies (e.g., one unit burns low-sulfur coal for compliance and the other combusts higher-sulfur coal), then either:

- i) Perform the retest with all units in normal operation; or
- ii) If this is not possible, due to circumstances beyond the control of the owner or operator (e.g., a forced unit outage), perform the retest with the available units operating and assess the test results as follows. Use the mercury concentration obtained in the retest for reporting purposes under this Part if the concentration is greater than or equal to the value obtained in the most recent test. If the retested value is lower than the mercury concentration from the previous test, continue using the higher value from the previous test for reporting purposes and use that same higher mercury concentration value in Equation 1 to determine the due date for the next retest, as described in subsection (e)(1)(C) of this Section.

C) If testing is done at the common stack, the due date for the next

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- 7180 scheduled retest must be determined as follows:
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 7182 i) Substitute the maximum potential flow rate for the common
 7183 stack (as defined in the monitoring plan) and the highest
 7184 mercury concentration from any test run (or 0.50 µg/scm, if
 7185 greater) into Equation 1; and
 7186
 7187 ii) If the value of E obtained from Equation 1, rounded to the
 7188 nearest ounce, is greater than 144 times the number of units
 7189 sharing the common stack, but less than or equal to 464
 7190 times the number of units sharing the stack, the next retest
 7191 is due in two QA operating quarters; or
 7192
 7193 iii) If the value of E obtained from Equation 1, rounded to the
 7194 nearest ounce, is less than or equal to 144 times the number
 7195 of units sharing the common stack, the next retest is due in
 7196 four QA operating quarters.
 7197
 7198 2) For units with multiple stack or duct configurations, mercury emission
 7199 testing must be performed separately on each stack or duct, and the sum of
 7200 the estimated annual mercury mass emissions from the stacks or ducts
 7201 must not exceed 464 ounces of mercury per year. For reporting purposes,
 7202 the default mercury concentration used for each stack or duct must either
 7203 be the highest value obtained in any test run for that stack or 0.50 µg/scm,
 7204 whichever is greater.
 7205
 7206 3) For units with a main stack and bypass stack configuration, mercury
 7207 emission testing must be performed only on the main stack. For reporting
 7208 purposes, the default mercury concentration used for the main stack must
 7209 either be the highest value obtained in any test run for that stack or 0.50
 7210 µg/scm, whichever is greater. Whenever the main stack is bypassed, the
 7211 maximum potential mercury concentration, as defined in Section 2.1.3 of
 7212 Exhibit A to this Appendix, must be reported.
 7213
 7214 f) At the end of each calendar year, if the cumulative annual mercury mass
 7215 emissions from an affected unit have exceeded 464 ounces, then the owner must
 7216 install, certify, operate and maintain a mercury concentration monitoring system
 7217 or a sorbent trap monitoring system no later than 180 days after the end of the
 7218 calendar year in which the annual mercury mass emissions exceeded 464 ounces.
 7219 For common stack and multiple stack configurations, installation and certification
 7220 of a mercury concentration or sorbent trap monitoring system on each stack
 7221 (except for bypass stacks) is likewise required within 180 days after the end of the
 7222 calendar year, if:

- 7223
 7224 1) The annual mercury mass emissions at the common stack have exceeded
 7225 464 ounces times the number of affected units using the common stack; or
 7226
 7227 2) The sum of the annual mercury mass emissions from all of the multiple
 7228 stacks or ducts has exceeded 464 ounces; or
 7229
 7230 3) The sum of the annual mercury mass emissions from the main and bypass
 7231 stacks has exceeded 464 ounces.
 7232
 7233 g) For an affected unit that is using a mercury concentration CEMS or a sorbent trap
 7234 system under Section 1.15(a) of this Appendix to continuously monitor the
 7235 mercury mass emissions, the owner or operator may switch to the methodology in
 7236 Section 1.15(b) of this Appendix, provided that the applicable conditions in
 7237 subsections (c) through (f) of this Section are met.
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7239 **Section 1.16 Monitoring of Mercury Mass Emissions and Heat Input at Common and**
 7240 **Multiple Stacks**

- 7241
 7242 a) Unit Utilizing Common Stack with Other Affected Units. When an affected unit
 7243 utilizes a common stack with one or more affected units, but no non-affected
 7244 units, the owner or operator must either:
 7245
 7246 1) Install, certify, operate and maintain the monitoring systems described in
 7247 Section 1.15(a) of this Appendix at the common stack record the
 7248 combined mercury mass emissions for the units exhausting to the common
 7249 stack. Alternatively, if, in accordance with Section 1.15(e) of this
 7250 Appendix, each of the units using the common stack is demonstrated to
 7251 emit less than 464 ounces of mercury per year, the owner or operator may
 7252 install, certify, operate and maintain the monitoring systems and perform
 7253 the mercury emission testing described under Section 1.15(b) of this
 7254 Appendix. If reporting of the unit heat input rate is required, determine the
 7255 hourly unit heat input rates either by:
 7256
 7257 A) Apportioning the common stack heat input rate to the individual
 7258 units according to the procedures in 40 CFR 75.16(e)(3),
 7259 incorporated by reference in Section 225.140; or
 7260
 7261 B) Installing, certifying, operating and maintaining a flow monitoring
 7262 system and diluent monitor in the duct to the common stack from
 7263 each unit; or
 7264
 7265 2) Install, certify, operate and maintain the monitoring systems and (if

7266 applicable) perform the mercury emission testing described in Section
 7267 1.15(a) or Section 1.15(b) of this Appendix in the duct to the common
 7268 stack from each unit.

7269
 7270 b) Unit Utilizing Common Stack with Nonaffected Units. When one or more
 7271 affected units utilizes a common stack with one or more nonaffected units, the
 7272 owner or operator must either:

7273
 7274 1) Install, certify, operate and maintain the monitoring systems and (if
 7275 applicable) perform the mercury emission testing described in Section
 7276 1.15(a) or Section 1.15(b) of this Appendix in the duct to the common
 7277 stack from each affected unit; or

7278
 7279 2) Install, certify, operate and maintain the monitoring systems described in
 7280 Section 1.15(a) of this Appendix in the common stack; and

7281
 7282 A) Install, certify, operate and maintain the monitoring systems and (if
 7283 applicable) perform the mercury emission testing described in
 7284 Section 1.15(a) or (b) of this Appendix in the duct to the common
 7285 stack from each non-affected unit. The designated representative
 7286 must submit a petition to the Agency to allow a method of
 7287 calculating and reporting the mercury mass emissions from the
 7288 affected units as the difference between mercury mass emissions
 7289 measured in the common stack and mercury mass emissions
 7290 measured in the ducts of the non-affected units, not to be reported
 7291 as an hourly value less than zero. The Agency may approve such a
 7292 method whenever the designated representative demonstrates, to
 7293 the satisfaction of the Agency, that the method ensures that the
 7294 mercury mass emissions from the affected units are not
 7295 underestimated; or

7296
 7297 B) Count the combined emissions measured at the common stack as
 7298 the mercury mass emissions for the affected units, for
 7299 recordkeeping and compliance purposes, in accordance with
 7300 subsection (a) of this Section; or

7301
 7302 C) Submit a petition to the Agency to allow use of a method for
 7303 apportioning mercury mass emissions measured in the common
 7304 stack to each of the units using the common stack and for reporting
 7305 the mercury mass emissions. The Agency may approve such a
 7306 method whenever the designated representative demonstrates, to
 7307 the satisfaction of the Agency, that the method ensures that the
 7308 mercury mass emissions from the affected units are not

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underestimated.

3) If the monitoring option in subsection (b)(2) of this Section is selected, and if heat input is required to be reported under this Part, the owner or operator must either:

A) Apportion the common stack heat input rate to the individual units according to the procedures in 40 CFR 75.16(e)(3), incorporated by reference in Section 225.140; or

B) Install a flow monitoring system and a diluent gas (O₂ or CO₂) monitoring system in the duct leading from each affected unit to the common stack, and measure the heat input rate in each duct, according to Section 2.2 of Exhibit C to this Appendix.

c) Unit With a Main Stack and a Bypass Stack. Whenever any portion of the flue gases from an affected unit can be routed through a bypass stack to avoid the mercury monitoring systems installed on the main stack, the owner and operator must either:

1) Install, certify, operate and maintain the monitoring systems described in Section 1.15(a) of this Appendix on both the main stack and the bypass stack and calculate mercury mass emissions for the unit as the sum of the mercury mass emissions measured at the two stacks;

2) Install, certify, operate and maintain the monitoring systems described in Section 1.15(a) of this Appendix at the main stack and measure mercury mass emissions at the bypass stack using the appropriate reference methods in Section 1.6(b) of this Appendix. Calculate mercury mass emissions for the unit as the sum of the emissions recorded by the installed monitoring systems on the main stack and the emissions measured by the reference method monitoring systems;

3) Install, certify, operate and maintain the monitoring systems and (if applicable) perform the mercury emission testing described in Section 1.15(a) or (b) of this Appendix only on the main stack. If this option is chosen, it is not necessary to designate the exhaust configuration as a multiple stack configuration in the monitoring plan required under Section 1.10 of this Appendix, since only the main stack is monitored; or

4) If the monitoring option in subsection (c)(1) or (2) of this Section is selected, and if heat input is required to be reported under this Part, the owner or operator must:

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- A) Use the installed flow and diluent monitors to determine the hourly heat input rate at each stack (mmBtu/hr), according to Section 2.2 of Exhibit C to this Appendix; and
 - B) Calculate the hourly heat input at each stack (in mmBtu) by multiplying the measured stack heat input rate by the corresponding stack operating time; and
 - C) Determine the hourly unit heat input by summing the hourly stack heat input values.
- d) Unit With Multiple Stack or Duct Configuration. When the flue gases from an affected unit discharge to the atmosphere through more than one stack, or when the flue gases from an affected unit utilize two or more ducts feeding into a single stack and the owner or operator chooses to monitor in the ducts rather than in the stack, the owner or operator must either:
- 1) Install, certify, operate and maintain the monitoring systems and (if applicable) perform the mercury emission testing described in Section 1.15(a) or (b) of this Appendix in each of the multiple stacks and determine mercury mass emissions from the affected unit as the sum of the mercury mass emissions recorded for each stack. If another unit also exhausts flue gases into one of the monitored stacks, the owner or operator must comply with the applicable requirements of subsections (a) and (b) of this Section, in order to properly determine the mercury mass emissions from the units using that stack;
 - 2) Install, certify, operate and maintain the monitoring systems and (if applicable) perform the mercury emission testing described in Section 1.15(a) or (b) of this Appendix in each of the ducts that feed into the stack, and determine mercury mass emissions from the affected unit using the sum of the mercury mass emissions measured at each duct, except that where another unit also exhausts flue gases to one or more of the stacks, the owner or operator must also comply with the applicable requirements of subsections (a) and (b) of this Section to determine and record mercury mass emissions from the units using that stack; or
 - 3) If the monitoring option in subsection (d)(1) or (2) of this Section is selected, and if heat input is required to be reported under this Part, the owner or operator must:

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- A) Use the installed flow and diluent monitors to determine the hourly heat input rate at each stack or duct (mmBtu/hr), according to Section 2.2 of Exhibit C to this Appendix; and
 - B) Calculate the hourly heat input at each stack or duct (in mmBtu) by multiplying the measured stack (or duct) heat input rate by the corresponding stack (or duct) operating time; and
 - C) Determine the hourly unit heat input by summing the hourly stack (or duct) heat input values.

7408 **Section 1.17 Calculation of mercury mass emissions and heat input rate**

7409
7410 The owner or operator must calculate mercury mass emissions and heat input rate in accordance
7411 with the procedures in Sections 4.1 through 4.3 of Exhibit F to this Appendix.
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7413 **Section 1.18 Recordkeeping and reporting**

- 7414
7415 a) General recordkeeping provisions. The owner or operator of any affected unit
7416 must maintain for each affected unit and each non-affected unit under Section
7417 1.16(b)(2)(B) of this Appendix a file of all measurements, data, reports, and other
7418 information required by this part at the source in a form suitable for inspection for
7419 at least 3 years from the date of each record. Except for the certification data
7420 required in Section 1.11(a)(4) of this Appendix and the initial submission of the
7421 monitoring plan required in Section 1.11(a)(5) of this Appendix, the data must be
7422 collected beginning with the earlier of the date of provisional certification or the
7423 compliance deadline in Section 1.14(b) of this Appendix. The certification data
7424 required in Section 1.11(a)(4) of this Appendix must be collected beginning with
7425 the date of the first certification test performed. The file must contain the
7426 following information:
7427
- 1) The information required in Sections 1.11(a)(2), (a)(4), (a)(5), (a)(6), (b),
7428 (c) (if applicable), (d), and (e) or (f) of this Appendix (as applicable);
7429
 - 2) The information required in Section 1.12 of this Appendix, for units with
7430 flue gas desulfurization systems or add-on mercury emission controls;
7431
 - 3) For affected units using mercury CEMS or sorbent trap monitoring
7432 systems, for each hour when the unit is operating, record the mercury mass
7433 emissions, calculated in accordance with Section 4 of Exhibit C to this
7434 Appendix.
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- 4) Heat input and mercury methodologies for the hour; and
 - 5) Formulas from the monitoring plan for total mercury mass emissions and heat input rate (if applicable);
 - b) Certification, quality assurance and quality control record provisions. The owner or operator of any affected unit must record the applicable information in Section 1.13 of this Appendix for each affected unit or group of units monitored at a common stack and each non-affected unit under Section 1.16(b)(2)(B) of this Appendix.
 - c) Monitoring plan recordkeeping provisions.
 - 1) General provisions. The owner or operator of an affected unit must prepare and maintain a monitoring plan for each affected unit or group of units monitored at a common stack and each non-affected unit under Section 1.16(b)(2)(B) of this Appendix. The monitoring plan must contain sufficient information on the continuous monitoring systems and the use of data derived from these systems to demonstrate that all the unit's mercury emissions are monitored and reported.
 - 2) Updates. Whenever the owner or operator makes a replacement, modification, or change in a certified continuous monitoring system or alternative monitoring system under 40 CFR 75, subpart E, incorporated by reference in Section 225.140, including a change in the automated data acquisition and handling system or in the flue gas handling system, that affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), then the owner or operator must update the monitoring plan.
 - 3) Contents of the monitoring plan. Each monitoring plan must contain the information in Section 1.10(d)(1) of this Appendix in electronic format and the information in Section 1.10(d)(2) in hardcopy format.
 - d) General reporting provisions.
 - 1) The designated representative for an affected unit must comply with all reporting requirements in this Section and with any additional requirements set forth in 35 Ill. Adm. Code 225.
 - 2) The designated representative for an affected unit must submit the following for each affected unit or group of units monitored at a common

- 7481 stack and each non-affected unit under Section 1.16(b)(2)(B) of this
 7482 Appendix:
 7483
 7484 A) Monitoring plans in accordance with subsection (e) of this Section;
 7485 and
 7486
 7487 B) Quarterly reports in accordance with subsection (f) of this Section.
 7488
 7489 3) Other petitions and communications. The designated representative for an
 7490 affected unit must submit petitions, correspondence, application forms,
 7491 and petition-related test results in accordance with the provisions in
 7492 Section 1.14(f) of this Appendix.
 7493
 7494 4) Quality assurance RATA reports. If requested by the Agency, the
 7495 designated representative of an affected unit must submit the quality
 7496 assurance RATA report for each affected unit or group of units monitored
 7497 at a common stack and each non-affected unit under Section 1.16(b)(2)(B)
 7498 of this Appendix by the later of 45 days after completing a quality
 7499 assurance RATA according to Section 2.3 of Exhibit B to this Appendix
 7500 or 15 days after receiving the request. The designated representative must
 7501 report the hardcopy information required by Section 1.13(a)(9) of this
 7502 Appendix to the Agency.
 7503
 7504 5) Notifications. The designated representative for an affected unit must
 7505 submit written notice to the Agency according to the provisions in 40 CFR
 7506 75.61, incorporated by reference in Section 225.140, for each affected unit
 7507 or group of units monitored at a common stack and each non-affected unit
 7508 under Section 1.16(b)(2)(B) of this Appendix.
 7509
 7510 e) Monitoring plan reporting.
 7511
 7512 1) Electronic submission. The designated representative for an affected unit
 7513 must submit to the Agency and USEPA, or an alternate Agency designee
 7514 if one is specified, a complete, electronic, up-to-date monitoring plan file
 7515 in a format specified by the Agency for each affected unit or group of
 7516 units monitored at a common stack and each non-affected unit under
 7517 Section 1.16(b)(2)(B) of this Appendix, as follows: No later than 21 days
 7518 prior to the commencement of initial certification testing; at the time of a
 7519 certification or recertification application submission; and whenever an
 7520 update of the electronic monitoring plan is required, either under Section
 7521 1.10 of this Appendix or elsewhere in this Appendix.
 7522
 7523 2) Hardcopy submission. The designated representative of an affected unit

7524 must submit all of the hardcopy information required under Section 1.10
 7525 of this Appendix, for each affected unit or group of units monitored at a
 7526 common stack and each non-affected unit under Section 1.16(b)(2)(B) of
 7527 this Appendix, to the Agency prior to initial certification. Thereafter, the
 7528 designated representative must submit hardcopy information only if that
 7529 portion of the monitoring plan is revised. The designated representative
 7530 must submit the required hardcopy information as follows: no later than
 7531 21 days prior to the commencement of initial certification testing; with
 7532 any certification or recertification application, if a hardcopy monitoring
 7533 plan change is associated with the recertification event; and within 30 days
 7534 after any other event with which a hardcopy monitoring plan change is
 7535 associated, pursuant to Section 1.10(b) of this Appendix. Electronic
 7536 submittal of all monitoring plan information, including hardcopy portions,
 7537 is permissible provided that a paper copy of the hardcopy portions can be
 7538 furnished upon request.

7539
 7540 f) Quarterly reports.

7541
 7542 1) Electronic submission. Electronic quarterly reports must be submitted,
 7543 beginning with the calendar quarter containing the compliance date in
 7544 Section 1.14(b) of this Appendix, unless otherwise specified in 35 Ill.
 7545 Adm. Code 225. The designated representative for an affected unit must
 7546 report the data and information in this subsection (f)(1) and the applicable
 7547 compliance certification information in subsection (f)(2) of this Section to
 7548 the Agency and USEPA, or an alternate Agency designee if one is
 7549 specified, quarterly in a format specified by the Agency, except as
 7550 otherwise provided in 40 CFR 75.64(a), incorporated by reference in
 7551 Section 225.140, for units in long-term cold storage. Each electronic
 7552 report must be submitted to the Agency within 45 days following the end
 7553 of each calendar quarter. Except as otherwise provided in 40 CFR
 7554 75.64(a)(4) and (a)(5), incorporated by reference in Section 225.140, each
 7555 electronic report must include the date of report generation and the
 7556 following information for each affected unit or group of units monitored at
 7557 a common stack:

7558
 7559 A) The facility information in 40 CFR 75.64(a)(3), incorporated by
 7560 reference in Section 225.140; and

7561
 7562 B) The information and hourly data required in subsections (a) and (b)
 7563 of this Section, except for:

7564
 7565 i) Descriptions of adjustments, corrective action, and
 7566 maintenance;

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- ii) Information which is incompatible with electronic reporting (e.g., field data sheets, lab analyses, quality control plan);
 - iii) For units with flue gas desulfurization systems or with add-on mercury emission controls, the parametric information in Section 1.12 of this Appendix;
 - iv) Information required by Section 1.11(d) of this Appendix concerning the causes of any missing data periods and the actions taken to cure those causes;
 - v) Hardcopy monitoring plan information required by Section 1.10 of this Appendix and hardcopy test data and results required by Section 1.13 of this Appendix;
 - vi) Records of flow polynomial equations and numerical values required by Section 1.13(a)(5)(E) of this Appendix;
 - vii) Stratification test results required as part of the RATA supplementary records under Section 1.13(a)(7) of this Appendix;
 - viii) Data and results of RATAs that are aborted or invalidated due to problems with the reference method or operational problems with the unit and data and results of linearity checks that are aborted or invalidated due to operational problems with the unit;
 - ix) Supplementary RATA information required under Section 1.13(a)(7) of this Appendix, except that: the applicable data elements under Section 1.13(a)(7)(B)(i) through (xx) of this Appendix and under Section 1.13(a)(7)(C)(i) through (xiii) of this Appendix must be reported for flow RATAs at circular or rectangular stacks (or ducts) in which angular compensation for yaw and/or pitch angles is used (i.e., Method 2F or 2G in appendices A-1 and A-2 to 40 CFR 60, incorporated by reference in Section 225.140), with or without wall effects adjustments; the applicable data elements under Section 1.13(a)(7)(B)(i) through (xx) of this Appendix and under Section 1.13(a)(7)(C)(i) through (xiii) of this Appendix must be reported for any flow RATA run at a circular stack in which Method 2 in appendices A-1

7610 and A-2 to 40 CFR 60, incorporated by reference in Section
 7611 225.140, is used and a wall effects adjustment factor is
 7612 determined by direct measurement; the data under Section
 7613 1.13(a)(7)(B)(xx) of this Appendix must be reported for all
 7614 flow RATAs at circular stacks in which Method 2 in
 7615 appendices A-1 and A-2 to 40 CFR 60, incorporated by
 7616 reference in Section 225.140, is used and a default wall
 7617 effects adjustment factor is applied; and the data under
 7618 Section 1.13(a)(7)(I)(i) through (vi) must be reported for all
 7619 flow RATAs at rectangular stacks or ducts in which
 7620 Method 2 in appendices A-1 and A-2 to 40 CFR 60,
 7621 incorporated by reference in Section 225.140, is used and a
 7622 wall effects adjustment factor is applied.

7623
 7624 x) For units using sorbent trap monitoring systems, the hourly
 7625 gas flow meter readings taken between the initial and final
 7626 meter readings for the data collection period; and

7627
 7628 C) Ounces of mercury emitted during quarter and cumulative ounces
 7629 of mercury emitted in the year-to-date (rounded to the nearest
 7630 thousandth); and

7631
 7632 D) Unit or stack operating hours for quarter, cumulative unit or stack
 7633 operating hours for year-to-date; and

7634
 7635 E) Reporting period heat input (if applicable) and cumulative, year-to-
 7636 date heat input.

7637
 7638 2) Compliance certification.

7639
 7640 A) The designated representative must certify that the monitoring plan
 7641 information in each quarterly electronic report (i.e., component and
 7642 system identification codes, formulas, etc.) represent current
 7643 operating conditions for the affected units.

7644
 7645 B) The designated representative must submit and sign a compliance
 7646 certification in support of each quarterly emissions monitoring
 7647 report based on reasonable inquiry of those persons with primary
 7648 responsibility for ensuring that all of the unit's emissions are
 7649 correctly and fully monitored. The certification must state that:

7650
 7651 i) The monitoring data submitted were recorded in
 7652 accordance with the applicable requirements of this

- 7653 Appendix, including the quality assurance procedures and
7654 specifications; and
7655
7656 ii) With regard to a unit with an FGD system or with add-on
7657 mercury emission controls, that for all hours where
7658 mercury data is missing in accordance with Section 1.13(b)
7659 of this Appendix, the add-on emission controls were
7660 operating within the range of parameters listed in the
7661 quality-assurance plan for the unit (or that quality-assured
7662 SO₂ CEMS data were available to document proper
7663 operation of the emission controls).
7664
7665 3) Additional reporting requirements. The designated representative must
7666 also comply with all of the quarterly reporting requirements in 40 CFR
7667 75.64(d), (f), and (g), incorporated by reference in Section 225.140.
7668

7669 **Exhibit A to Appendix B – Specifications and Test Procedures**

7670

7671 **1. Installation and Measurement Location**

7672

7673 **1.1 Gas and Mercury Monitors**

7674

7675 Following the procedures in Section 8.1.1 of Performance Specification 2 in Appendix B to 40
 7676 CFR 60, incorporated by reference in Section 225.140, install the pollutant concentration
 7677 monitor or monitoring system at a location where the pollutant concentration and emission rate
 7678 measurements are directly representative of the total emissions from the affected unit. Select a
 7679 representative measurement point or path for the monitor probes (or for the path from the
 7680 transmitter to the receiver) such that the CO₂, O₂, concentration monitoring system, mercury
 7681 concentration monitoring system, or sorbent trap monitoring system will pass the relative
 7682 accuracy test (see Section 6 of this Exhibit).

7683

7684 It is recommended that monitor measurements be made at locations where the exhaust gas
 7685 temperature is above the dew-point temperature. If the cause of failure to meet the relative
 7686 accuracy tests is determined to be the measurement location, relocate the monitor probes.

7687

7688 **1.1.1 Point Monitors**

7689

7690 Locate the measurement point (1) within the centroidal area of the stack or duct cross section, or
 7691 (2) no less than 1.0 meter from the stack or duct wall.

7692

7693 **1.2 Flow Monitors**

7694

7695 Install the flow monitor in a location that provides representative volumetric flow over all
 7696 operating conditions. Such a location is one that provides an average velocity of the flue gas flow
 7697 over the stack or duct cross section and is representative of the pollutant concentration monitor
 7698 location. Where the moisture content of the flue gas affects volumetric flow measurements, use
 7699 the procedures in both Reference Methods 1 and 4 of appendix A to 40 CFR 60, incorporated by
 7700 reference in Section 225.140, to establish a proper location for the flow monitor. The Illinois
 7701 EPA recommends (but does not require) performing a flow profile study following the
 7702 procedures in 40 CFR 60, appendix A, Method 1, Sections 11.5 or 11.4, incorporated by
 7703 reference in Section 225.140, for each of the three operating or load levels indicated in Section
 7704 6.5.2.1 of this Exhibit to determine the acceptability of the potential flow monitor location and to
 7705 determine the number and location of flow sampling points required to obtain a representative
 7706 flow value. The procedure in 40 CFR 60, appendix A, Test Method 1, Section 11.5, incorporated
 7707 by reference in Section 225.140, may be used even if the flow measurement location is greater
 7708 than or equal to 2 equivalent stack or duct diameters downstream or greater than or equal to ½
 7709 duct diameter upstream from a flow disturbance. If a flow profile study shows that cyclonic (or
 7710 swirling) or stratified flow conditions exist at the potential flow monitor location that are likely
 7711 to prevent the monitor from meeting the performance specifications of this part, then the Agency

7712 recommends either (1) selecting another location where there is no cyclonic (or swirling) or
 7713 stratified flow condition, or (2) eliminating the cyclonic (or swirling) or stratified flow condition
 7714 by straightening the flow, e.g., by installing straightening vanes. The Agency also recommends
 7715 selecting flow monitor locations to minimize the effects of condensation, coating, erosion, or
 7716 other conditions that could adversely affect flow monitor performance.

7717
 7718 1.2.1 Acceptability of Monitor Location
 7719

7720 The installation of a flow monitor is acceptable if either (1) the location satisfies the minimum
 7721 siting criteria of Method 1 in appendix A to 40 CFR 60, incorporated by reference in Section
 7722 225.140 (i.e., the location is greater than or equal to eight stack or duct diameters downstream
 7723 and two diameters upstream from a flow disturbance; or, if necessary, two stack or duct
 7724 diameters downstream and one-half stack or duct diameter upstream from a flow disturbance), or
 7725 (2) the results of a flow profile study, if performed, are acceptable (i.e., there are no cyclonic (or
 7726 swirling) or stratified flow conditions), and the flow monitor also satisfies the performance
 7727 specifications of this part. If the flow monitor is installed in a location that does not satisfy these
 7728 physical criteria, but nevertheless the monitor achieves the performance specifications of this
 7729 part, then the location is acceptable, notwithstanding the requirements of this Section.

7730
 7731 1.2.2 Alternative Monitoring Location
 7732

7733 Whenever the owner or operator successfully demonstrates that modifications to the exhaust duct
 7734 or stack (such as installation of straightening vanes, modifications of ductwork, and the like) are
 7735 necessary for the flow monitor to meet the performance specifications, the Agency may approve
 7736 an interim alternative flow monitoring methodology and an extension to the required certification
 7737 date for the flow monitor.

7738
 7739 Where no location exists that satisfies the physical siting criteria in Section 1.2.1, where the
 7740 results of flow profile studies performed at two or more alternative flow monitor locations are
 7741 unacceptable, or where installation of a flow monitor in either the stack or the ducts is
 7742 demonstrated to be technically infeasible, the owner or operator may petition the Agency for an
 7743 alternative method for monitoring flow.

7744
 7745 2. Equipment Specifications
 7746

7747 2.1 Instrument Span and Range
 7748

7749 In implementing Sections 2.1.1 through 2.1.2 of this Exhibit, set the measurement range for each
 7750 parameter (CO₂, O₂, or flow rate) high enough to prevent full-scale exceedances from occurring,
 7751 yet low enough to ensure good measurement accuracy and to maintain a high signal-to-noise
 7752 ratio. To meet these objectives, select the range such that the majority of the readings obtained
 7753 during typical unit operation are kept, to the extent practicable, between 20.0 and 80.0 percent of
 7754 the full-scale range of the instrument.

2.1.1 CO₂ and O₂ Monitors

For an O₂ monitor (including O₂ monitors used to measure CO₂ emissions or percentage moisture), select a span value between 15.0 and 25.0 percent O₂. For a CO₂ monitor installed on a boiler, select a span value between 14.0 and 20.0 percent CO₂. For a CO₂ monitor installed on a combustion turbine, an alternative span value between 6.0 and 14.0 percent CO₂ may be used. An alternative CO₂ span value below 6.0 percent may be used if an appropriate technical justification is included in the hardcopy monitoring plan. An alternative O₂ span value below 15.0 percent O₂ may be used if an appropriate technical justification is included in the monitoring plan (e.g., O₂ concentrations above a certain level create an unsafe operating condition). Select the full-scale range of the instrument to be consistent with Section 2.1 of this Exhibit and to be greater than or equal to the span value. Select the calibration gas concentrations for the daily calibration error tests and linearity checks in accordance with Section 5.1 of this Exhibit, as percentages of the span value. For O₂ monitors with span values ≥ 21.0 percent O₂, purified instrument air containing 20.9 percent O₂ may be used as the high-level calibration material. If a dual-range or autoranging diluent analyzer is installed, the analyzer may be represented in the monitoring plan as a single component, using a special component type code specified by the USEPA to satisfy the requirements of 40 CFR 75.53(e)(1)(iv)(D), incorporated by reference in Section 225.140.

2.1.2 Flow Monitors

Select the full-scale range of the flow monitor so that it is consistent with Section 2.1 of this Exhibit and can accurately measure all potential volumetric flow rates at the flow monitor installation site.

2.1.2.1 Maximum Potential Velocity and Flow Rate

For this purpose, determine the span value of the flow monitor using the following procedure. Calculate the maximum potential velocity (MPV) using Equation A-3a or A-3b or determine the MPV (wet basis) from velocity traverse testing using Reference Method 2 (or its allowable alternatives) in appendix A to 40 CFR 60, incorporated by reference in Section 225.140. If using test values, use the highest average velocity (determined from the Method 2 traverses) measured at or near the maximum unit operating load (or, for units that do not produce electrical or thermal output, at the normal process operating conditions corresponding to the maximum stack gas flow rate). Express the MPV in units of wet standard feet per minute (fpm). For the purpose of providing substitute data during periods of missing flow rate data in accordance with 40 CFR 75.31 and 75.33 and as required elsewhere in this part, calculate the maximum potential stack gas flow rate (MPF) in units of standard cubic feet per hour (scfh), as the product of the MPV (in units of wet, standard fpm) times 60, times the cross-sectional area of the stack or duct (in ft²) at the flow monitor location.

7798

7799

$$MPV = \left(\frac{F_d H_f}{A} \right) \left(\frac{20.9}{20.9 - \%O_{2d}} \right) \left(\frac{100}{100 - \%H_2O} \right) \quad \text{(Equation A-3a)}$$

7800

7801

or

7802

$$MPV = \left(\frac{F_c H_f}{A} \right) \left(\frac{100}{\%CO_{2d}} \right) \left(\frac{100}{100 - \%H_2O} \right) \quad \text{(Equation A-3b)}$$

7803

7804

7805

Where:

- MPV = maximum potential velocity (fpm, standard wet basis).
- F_d = dry-basis F factor (dscf/mmBtu) from Table 1, Section 3.3.5 of Appendix F, 40 CFR 75.
- F_c = carbon-based F factor (scf CO₂/mmBtu) from Table 1, Section 3.3.5 of Appendix F, 40 CFR 75.
- H_f = maximum heat input (mmBtu/minute) for all units, combined, exhausting to the stack or duct where the flow monitor is located.
- A = inside cross sectional area (ft²) of the flue at the flow monitor location.
- %O_{2d} = maximum oxygen concentration, percent dry basis, under normal operating conditions.
- %CO_{2d} = minimum carbon dioxide concentration, percent dry basis, under normal operating conditions.
- %H₂O = maximum percent flue gas moisture content under normal operating conditions.

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7808

2.1.2.2 Span Values and Range

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Determine the span and range of the flow monitor as follows. Convert the MPV, as determined in Section 2.1.2.1 of this Exhibit, to the same measurement units of flow rate that are used for daily calibration error tests (e.g., scfh, kscfh, kacfm, or differential pressure (inches of water)). Next, determine the "calibration span value" by multiplying the MPV (converted to equivalent daily calibration error units) by a factor no less than 1.00 and no greater than 1.25, and rounding up the result to at least two significant figures. For calibration span values in inches of water, retain at least two decimal places. Select appropriate reference signals for the daily calibration error tests as percentages of the calibration span value, as specified in Section 2.2.2.1 of this Exhibit. Finally, calculate the "flow rate span value" (in scfh) as the product of the MPV, as determined in Section 2.1.2.1 of this Exhibit, times the same factor (between 1.00 and 1.25) that was used to calculate the calibration span value. Round off the flow rate span value to the nearest

7820 1000 scfh. Select the full-scale range of the flow monitor so that it is greater than or equal to the
 7821 span value and is consistent with Section 2.1 of this Exhibit. Include in the monitoring plan for
 7822 the unit: calculations of the MPV, MPF, calibration span value, flow rate span value, and full-
 7823 scale range (expressed both in scfh and, if different, in the measurement units of calibration).

7824
 7825 2.1.2.3 Adjustment of Span and Range
 7826

7827 For each affected unit or common stack, the owner or operator must make a periodic evaluation
 7828 of the MPV, span, and range values for each flow rate monitor (at a minimum, an annual
 7829 evaluation is required) and must make any necessary span and range adjustments with
 7830 corresponding monitoring plan updates, as described in subsections (a) through (c) of this
 7831 Section 2.1.2.3. Span and range adjustments may be required, for example, as a result of changes
 7832 in the fuel supply, changes in the stack or ductwork configuration, changes in the manner of
 7833 operation of the unit, or installation or removal of emission controls. In implementing the
 7834 provisions in subsections (a) and (b) of this Section 2.1.2.3, note that flow rate data recorded
 7835 during short-term, non-representative operating conditions (e.g., a trial burn of a different type of
 7836 fuel) must be excluded from consideration. The owner or operator must keep the results of the
 7837 most recent span and range evaluation on-site, in a format suitable for inspection. Make each
 7838 required span or range adjustment no later than 45 days after the end of the quarter in which the
 7839 need to adjust the span or range is identified.

7840
 7841 a) If the fuel supply, stack or ductwork configuration, operating parameters, or other
 7842 conditions change such that the maximum potential flow rate changes
 7843 significantly, adjust the span and range to assure the continued accuracy of the
 7844 flow monitor. A "significant" change in the MPV means that the guidelines of
 7845 Section 2.1 of this Exhibit can no longer be met, as determined by either a
 7846 periodic evaluation by the owner or operator or from the results of an audit by the
 7847 Agency. The owner or operator should evaluate whether any planned changes in
 7848 operation of the unit may affect the flow of the unit or stack and should plan any
 7849 necessary span and range changes needed to account for these changes, so that
 7850 they are made in as timely a manner as practicable to coordinate with the
 7851 operational changes. Calculate the adjusted calibration span and flow rate span
 7852 values using the procedures in Section 2.1.2.2 of this Exhibit.

7853
 7854 b) Whenever the full-scale range is exceeded during a quarter, provided that the
 7855 exceedance is not caused by a monitor out-of-control period, report 200.0 percent
 7856 of the current full-scale range as the hourly flow rate for each hour of the full-
 7857 scale exceedance. If the range is exceeded, make appropriate adjustments to the
 7858 flow rate span and range to prevent future full-scale exceedances. Calculate the
 7859 new calibration span value by converting the new flow rate span value from units
 7860 of scfh to units of daily calibration. A calibration error test must be performed and
 7861 passed to validate data on the new range.
 7862

7863 c) Whenever changes are made to the MPV, full-scale range, or span value of the
 7864 flow monitor, as described in subsections (a) and (b) of this Section, record and
 7865 report (as applicable) the new full-scale range setting, calculations of the flow rate
 7866 span value, calibration span value, and MPV in an updated monitoring plan for
 7867 the unit. The monitoring plan update must be made in the quarter in which the
 7868 changes become effective. Record and report the adjusted calibration span and
 7869 reference values as parts of the records for the calibration error test required by
 7870 Exhibit B to this Appendix. Whenever the calibration span value is adjusted, use
 7871 reference values for the calibration error test that meet the requirements of Section
 7872 2.2.2.1 of this Exhibit, based on the most recent adjusted calibration span value.
 7873 Perform a calibration error test according to Section 2.1.1 of Exhibit B to this
 7874 Appendix whenever making a change to the flow monitor span or range, unless
 7875 the range change also triggers a recertification under Section 1.4 of this Appendix.
 7876

7877 2.1.3 Mercury Monitors

7878
 7879 Determine the appropriate span and range values for each mercury pollutant concentration
 7880 monitor, so that all expected mercury concentrations can be determined accurately.
 7881

7882 2.1.3.1 Maximum Potential Concentration

7883
 7884 The maximum potential concentration depends upon the type of coal combusted in the unit. For
 7885 the initial MPC determination, there are three options:
 7886

- 7887 1) Use one of the following default values: 9 µg/scm for bituminous coal; 10
 7888 µg/scm for sub-bituminous coal; 16 µg/scm for lignite, and 1 µg/scm for
 7889 waste coal, i.e., anthracite culm or bituminous gob. If different coals are
 7890 blended, use the highest MPC for any fuel in the blend; or
 7891
- 7892 2) You may base the MPC on the results of site-specific emission testing
 7893 using one of the mercury reference methods in Section 1.6 of this
 7894 Appendix, if the unit does not have add-on mercury emission controls or a
 7895 flue gas desulfurization system, or if you test upstream of these control
 7896 devices. A minimum of 3 test runs are required at the normal operating
 7897 load. Use the highest total mercury concentration obtained in any of the
 7898 tests as the MPC; or
 7899
- 7900 3) You may base the MPC on 720 or more hours of historical CEMS data or
 7901 data from a sorbent trap monitoring system, if the unit does not have add-
 7902 on mercury emission controls or a flue gas desulfurization system (or if
 7903 the CEMS or sorbent trap system is located upstream of these control
 7904 devices) and if the mercury CEMS or sorbent trap system has been tested
 7905 for relative accuracy against one of the mercury reference methods in

7906 Section 1.6 of this Appendix and has met a relative accuracy specification
 7907 of 20.0% or less.

7908
 7909 2.1.3.2 Maximum Expected Concentration
 7910

7911 For units with FGD systems that significantly reduce mercury emissions (including fluidized bed
 7912 units that use limestone injection) and for units equipped with add-on mercury emission controls
 7913 (e.g., carbon injection), determine the maximum expected mercury concentration (MEC) during
 7914 normal, stable operation of the unit and emission controls. To calculate the MEC, substitute the
 7915 MPC value from Section 2.1.3.1 of this Exhibit into Equation A-2 in Section 2.1.1.2 of appendix
 7916 A to 40 CFR 75, incorporated by reference in Section 225.140. For units with add-on mercury
 7917 emission controls, base the percent removal efficiency on design engineering calculations. For
 7918 units with FGD systems, use the best available estimate of the mercury removal efficiency of the
 7919 FGD system.

7920
 7921 2.1.3.3 Span and Range Values
 7922

- 7923 a) For each mercury monitor, determine a high span value, by rounding the MPC
 7924 value from Section 2.1.3.1 of this Exhibit upward to the next highest multiple of
 7925 10 µg/scm.
- 7926
 7927 b) For an affected unit equipped with an FGD system or a unit with add-on mercury
 7928 emission controls, if the MEC value from Section 2.1.3.2 of this Exhibit is less
 7929 than 20 percent of the high span value from subsection (a) of this Section, and if
 7930 the high span value is 20 µg/scm or greater, define a second, low span value of 10
 7931 µg/scm.
- 7932
 7933 c) If only a high span value is required, set the full-scale range of the mercury
 7934 analyzer to be greater than or equal to the span value.
- 7935
 7936 d) If two span values are required, you may either:
- 7937
 7938 1) Use two separate (high and low) measurement scales, setting the range of
 7939 each scale to be greater than or equal to the high or low span value, as
 7940 appropriate; or
- 7941
 7942 2) Quality-assure two segments of a single measurement scale.
 7943

7944 2.1.3.4 Adjustment of Span and Range
 7945

7946 For each affected unit or common stack, the owner or operator must make a periodic evaluation
 7947 of the MPC, MEC, span, and range values for each mercury monitor (at a minimum, an annual
 7948 evaluation is required) and must make any necessary span and range adjustments, with

7949 corresponding monitoring plan updates. Span and range adjustments may be required, for
 7950 example, as a result of changes in the fuel supply, changes in the manner of operation of the unit,
 7951 or installation or removal of emission controls. In implementing the provisions in subsections (a)
 7952 and (b) of this Section, data recorded during short-term, non-representative process operating
 7953 conditions (e.g., a trial burn of a different type of fuel) must be excluded from consideration. The
 7954 owner or operator must keep the results of the most recent span and range evaluation on-site, in a
 7955 format suitable for inspection. Make each required span or range adjustment no later than 45
 7956 days after the end of the quarter in which the need to adjust the span or range is identified, except
 7957 that up to 90 days after the end of that quarter may be taken to implement a span adjustment if
 7958 the calibration gas concentrations currently being used for calibration error tests, system integrity
 7959 checks, and linearity checks are unsuitable for use with the new span value and new calibration
 7960 materials must be ordered.

- 7961
- 7962 a) The guidelines of Section 2.1 of this Exhibit do not apply to mercury monitoring
 7963 systems.
- 7964
- 7965 b) Whenever a full-scale range exceedance occurs during a quarter and is not caused
 7966 by a monitor out-of-control period, proceed as follows:
- 7967
- 7968 1) For monitors with a single measurement scale, report that the system was
 7969 out of range and invalid data was obtained until the readings come back
 7970 on-scale and, if appropriate, make adjustments to the MPC, span, and
 7971 range to prevent future full-scale exceedances; or
- 7972
- 7973 2) For units with two separate measurement scales, if the low range is
 7974 exceeded, no further action is required, provided that the high range is
 7975 available and is not out-of-control or out-of-service for any reason.
 7976 However, if the high range is not able to provide quality assured data at
 7977 the time of the low range exceedance or at any time during the
 7978 continuation of the exceedance, report that the system was out-of-control
 7979 until the readings return to the low range or until the high range is able to
 7980 provide quality assured data (unless the reason that the high-scale range is
 7981 not able to provide quality assured data is because the high-scale range has
 7982 been exceeded; if the high-scale range is exceeded follow the procedures
 7983 in subsection (b)(1) of this Section).
- 7984
- 7985 c) Whenever changes are made to the MPC, MEC, full-scale range, or span value of
 7986 the mercury monitor, record and report (as applicable) the new full-scale range
 7987 setting, the new MPC or MEC and calculations of the adjusted span value in an
 7988 updated monitoring plan. The monitoring plan update must be made in the quarter
 7989 in which the changes become effective. In addition, record and report the adjusted
 7990 span as part of the records for the daily calibration error test and linearity check
 7991 specified by Exhibit B to this Appendix. Whenever the span value is adjusted, use

7992 calibration gas concentrations that meet the requirements of Section 5.1 of this
 7993 Exhibit, based on the adjusted span value. When a span adjustment is so
 7994 significant that the calibration gas concentrations currently being used for
 7995 calibration error tests, system integrity checks and linearity checks are unsuitable
 7996 for use with the new span value, then a diagnostic linearity or 3-level system
 7997 integrity check using the new calibration gas concentrations must be performed
 7998 and passed. Use the data validation procedures in Section 1.4(b)(3) of this
 7999 Appendix, beginning with the hour in which the span is changed.

8000
 8001 2.2 Design for Quality Control Testing

8002
 8003 2.2.1 Pollutant Concentration and CO₂ or O₂ Monitors

- 8004
 8005 a) Design and equip each pollutant concentration and CO₂ or O₂ monitor with a
 8006 calibration gas injection port that allows a check of the entire measurement
 8007 system when calibration gases are introduced. For extractive and dilution type
 8008 monitors, all monitoring components exposed to the sample gas, (e.g., sample
 8009 lines, filters, scrubbers, conditioners, and as much of the probe as practicable) are
 8010 included in the measurement system. For in-situ type monitors, the calibration
 8011 must check against the injected gas for the performance of all active electronic
 8012 and optical components (e.g., transmitter, receiver, analyzer).
 8013
 8014 b) Design and equip each pollutant concentration or CO₂ or O₂ monitor to allow
 8015 daily determinations of calibration error (positive or negative) at the zero- and
 8016 mid- or high-level concentrations specified in Section 5.2 of this Exhibit.

8017
 8018 2.2.2 Flow Monitors

8019
 8020 Design all flow monitors to meet the applicable performance specifications.

8021
 8022 2.2.2.1 Calibration Error Test

8023
 8024 Design and equip each flow monitor to allow for a daily calibration error test consisting of at
 8025 least two reference values: Zero to 20 percent of span or an equivalent reference value (e.g.,
 8026 pressure pulse or electronic signal) and 50 to 70 percent of span. Flow monitor response, both
 8027 before and after any adjustment, must be capable of being recorded by the data acquisition and
 8028 handling system. Design each flow monitor to allow a daily calibration error test of the entire
 8029 flow monitoring system, from and including the probe tip (or equivalent) through and including
 8030 the data acquisition and handling system, or the flow monitoring system from and including the
 8031 transducer through and including the data acquisition and handling system.

8032
 8033 2.2.2.2 Interference Check

8034

- 8035 a) Design and equip each flow monitor with a means to ensure that the moisture
 8036 expected to occur at the monitoring location does not interfere with the proper
 8037 functioning of the flow monitoring system. Design and equip each flow monitor
 8038 with a means to detect, on at least a daily basis, pluggage of each sample line and
 8039 sensing port, and malfunction of each resistance temperature detector (RTD),
 8040 transceiver or equivalent.
- 8041
- 8042 b) Design and equip each differential pressure flow monitor to provide an automatic,
 8043 periodic back purging (simultaneously on both sides of the probe) or equivalent
 8044 method of sufficient force and frequency to keep the probe and lines sufficiently
 8045 free of obstructions on at least a daily basis to prevent velocity sensing
 8046 interference, and a means for detecting leaks in the system on at least a quarterly
 8047 basis (manual check is acceptable).
- 8048
- 8049 c) Design and equip each thermal flow monitor with a means to ensure on at least a
 8050 daily basis that the probe remains sufficiently clean to prevent velocity sensing
 8051 interference.
- 8052
- 8053 d) Design and equip each ultrasonic flow monitor with a means to ensure on at least
 8054 a daily basis that the transceivers remain sufficiently clean (e.g., back purging
 8055 system) to prevent velocity sensing interference.
- 8056

2.2.3 Mercury Monitors

8057

8058

8059 Design and equip each mercury monitor to permit the introduction of known concentrations of
 8060 elemental mercury and HgCl₂ separately, at a point immediately preceding the sample extraction
 8061 filtration system, such that the entire measurement system can be checked. If the mercury
 8062 monitor does not have a converter, the HgCl₂ injection capability is not required.

3. Performance Specifications

3.1 Calibration Error

- 8063
- 8064
- 8065
- 8066
- 8067
- 8068 a) The calibration error performance specifications in this Section apply only to 7-
 8069 day calibration error tests under Sections 6.3.1 and 6.3.2 of this Exhibit and to the
 8070 offline calibration demonstration described in Section 2.1.1.2 of Exhibit B to this
 8071 Appendix. The calibration error limits for daily operation of the continuous
 8072 monitoring systems required under this part are found in Section 2.1.4(a) of
 8073 Exhibit B to this Appendix.
- 8074
- 8075 b) The calibration error of a mercury concentration monitor must not deviate from
 8076 the reference value of either the zero or upscale calibration gas by more than 5.0
 8077 percent of the span value, as calculated using Equation A-5 of this Exhibit.

8078 Alternatively, if the span value is 10 µg/scm, the calibration error test results are
 8079 also acceptable if the absolute value of the difference between the monitor
 8080 response value and the reference value, R-A in Equation A-5 of this Exhibit, is ≤
 8081 1.0 µg/scm.
 8082

$$CE = \frac{|R - A|}{S} \times 100 \quad \text{(Equation A-5)}$$

8083
 8084
 8085 Where:
 8086

- CE = Calibration error as a percentage of the span of the instrument.
- R = Reference value of zero or upscale (high-level or mid-level, as applicable) calibration gas introduced into the monitoring system.
- A = Actual monitoring system response to the calibration gas.
- S = Span of the instrument, as specified in Section 2 of this Exhibit.

8087
 8088
 8089
 8090

3.2 Linearity Check

8091 For CO₂ or O₂ monitors (including O₂ monitors used to measure CO₂ emissions or percent
 8092 moisture):

- 8093
- 8094 a) The error in linearity for each calibration gas concentration (low-, mid-, and high-
 8095 levels) must not exceed or deviate from the reference value by more than 5.0
 8096 percent as calculated using Equation A-4 of this Exhibit; or
 8097
- 8098 b) The absolute value of the difference between the average of the monitor response
 8099 values and the average of the reference values, R-A in Equation A-4 of this
 8100 Exhibit, must be less than or equal to 0.5 percent CO₂ or O₂, whichever is less
 8101 restrictive.
 8102
- 8103 c) For the linearity check and the 3-level system integrity check of a mercury
 8104 monitor, which are required, respectively, under Section 1.4(c)(1)(B) and
 8105 (c)(1)(E) of this Appendix, the measurement error must not exceed 10.0 percent
 8106 of the reference value at any of the three gas levels. To calculate the measurement
 8107 error at each level, take the absolute value of the difference between the reference
 8108 value and mean CEM response, divide the result by the reference value, and then
 8109 multiply by 100. Alternatively, the results at any gas level are acceptable if the
 8110 absolute value of the difference between the average monitor response and the
 8111 average reference value, i.e., R-A in Equation A-4 of this Exhibit, does not exceed
 8112 0.8 µg/m³. The principal and alternative performance specifications in this
 8113 Section also apply to the single-level system integrity check described in Section

8114 2.6 of Exhibit B to this Appendix.

8115

8116
$$LE = \frac{|R - A|}{R} \times 100 \quad \text{(Equation A-4)}$$

8117

8118

8119

Where:

LE = Percentage linearity error, based upon the reference value.

R = Reference value of low-, mid-, or high-level calibration gas introduced into the monitoring system.

A = Average of the monitoring system responses.

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3.3 Relative Accuracy

3.3.1 Relative Accuracy for CO₂ and O₂ Monitors

The relative accuracy for CO₂ and O₂ monitors must not exceed 10.0 percent. The relative accuracy test results are also acceptable if the difference between the mean value of the CO₂ or O₂ monitor measurements and the corresponding reference method measurement mean value, calculated using equation A-7 of this Exhibit, does not exceed ± 1.0 percent CO₂ or O₂.

8130

$$d = \sum_{i=1}^n d_i \quad \text{(Equation A-7)}$$

8131

8132

8133

Where:

n = Number of data points.

d_i = The difference between a reference method value and the corresponding continuous emission monitoring system value (RM_i- CEM_i) at a given point in time i.

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3.3.2 Relative Accuracy for Flow Monitors

- a) The relative accuracy of flow monitors must not exceed 10.0 percent at any load (or operating) level at which a RATA is performed (i.e., the low-, mid-, or high-level, as defined in Section 6.5.2.1 of this Exhibit).
- b) For affected units where the average of the flow reference method measurements of gas velocity at a particular load (or operating) level of the relative accuracy test audit is less than or equal to 10.0 fps, the difference between the mean value of the flow monitor velocity measurements and the reference method mean value in fps at that level must not exceed ± 2.0 fps, wherever the 10.0 percent relative

8146 accuracy specification is not achieved.

8147
8148 3.3.3 Relative Accuracy for Moisture Monitoring Systems

8149
8150 The relative accuracy of a moisture monitoring system must not exceed 10.0 percent. The
8151 relative accuracy test results are also acceptable if the difference between the mean value of the
8152 reference method measurements (in percent H₂O) and the corresponding mean value of the
8153 moisture monitoring system measurements (in percent H₂O), calculated using Equation A-7 of
8154 this Exhibit does not exceed ± 1.5 percent H₂O.

8155
8156 3.3.4 Relative Accuracy for Mercury Monitoring Systems

8157
8158 The relative accuracy of a mercury concentration monitoring system or a sorbent trap monitoring
8159 system must not exceed 20.0 percent. Alternatively, for affected units where the average of the
8160 reference method measurements of mercury concentration during the relative accuracy test audit
8161 is less than 5.0 µg/scm, the test results are acceptable if the difference between the mean value of
8162 the monitor measurements and the reference method mean value does not exceed 1.0 µg/scm, in
8163 cases where the relative accuracy specification of 20.0 percent is not achieved.

8164
8165 3.4 Bias

8166
8167 3.4.1 Flow Monitors

8168
8169 Flow monitors must not be biased low as determined by the test procedure in Section 7.4 of this
8170 Exhibit. The bias specification applies to all flow monitors including those measuring an average
8171 gas velocity of 10.0 fps or less.

8172
8173 3.4.2 Mercury Monitoring Systems

8174
8175 Mercury concentration monitoring systems and sorbent trap monitoring systems must not be
8176 biased low as determined by the test procedure in Section 7.4 of this Exhibit.

8177
8178 3.5 Cycle Time

8179
8180 The cycle time for mercury concentration monitors, oxygen monitors used to determine percent
8181 moisture, and any other monitoring component of a continuous emission monitoring system that
8182 is required to perform a cycle time test must not exceed 15 minutes.

8183
8184 4. Data Acquisition and Handling Systems

8185
8186 Automated data acquisition and handling systems must read and record the full range of pollutant
8187 concentrations and volumetric flow from zero through span and provide a continuous, permanent
8188 record of all measurements and required information as an ASCII flat file capable of

8189 transmission both by direct computer-to-computer electronic transfer via modem and EPA-
 8190 provided software and by an IBM-compatible personal computer diskette. These systems also
 8191 must have the capability of interpreting and converting the individual output signals from a flow
 8192 monitor, a CO₂ monitor, an O₂ monitor, a moisture monitoring system, a mercury concentration
 8193 monitoring system, and a sorbent trap monitoring system, to produce a continuous readout of
 8194 pollutant emission rates or pollutant mass emissions (as applicable) in the appropriate units (e.g.,
 8195 lb/hr, lb/mmBtu, ounces/hr, tons/hr). These systems also must have the capability of interpreting
 8196 and converting the individual output signals from a flow monitor to produce a continuous
 8197 readout of pollutant mass emission rates in the units of the standard. Where CO₂ emissions are
 8198 measured with a continuous emission monitoring system, the data acquisition and handling
 8199 system must also produce a readout of CO₂ mass emissions in tons.

8200
 8201 Data acquisition and handling systems must also compute and record monitor calibration error,
 8202 any bias adjustments to mercury pollutant concentration data, flow rate data, or mercury emission
 8203 rate data.

8204
 8205 5. Calibration Gas

8206
 8207 5.1 Reference Gases

8208
 8209 For the purposes of this Appendix, calibration gases include the following:

8210
 8211 5.1.1 Standard Reference Materials (SRM)

8212
 8213 These calibration gases may be obtained from the National Institute of Standards and
 8214 Technology (NIST) at the following address: Quince Orchard and Cloppers Road, Gaithersburg,
 8215 MD 20899-0001.

8216
 8217 5.1.2 SRM-Equivalent Compressed Gas Primary Reference Material (PRM)

8218
 8219 Contact the Gas Metrology Team, Analytical Chemistry Division, Chemical Science and
 8220 Technology Laboratory of NIST, at the address in Section 5.1.1, for a list of vendors and
 8221 cylinder gases.

8222
 8223 5.1.3 NIST Traceable Reference Materials

8224
 8225 Contact the Gas Metrology Team, Analytical Chemistry Division, Chemical Science and
 8226 Technology Laboratory of NIST, at the address in Section 5.1.1, for a list of vendors and
 8227 cylinder gases that meet the definition for a NIST Traceable Reference Material (NTRM)
 8228 provided in 40 CFR 72.2, incorporated by reference in Section 225.140.

8229
 8230 5.1.4 EPA Protocol Gases

8231

- 8232 a) An EPA Protocol Gas is a calibration gas mixture prepared and analyzed
8233 according to Section 2 of the "EPA Traceability Protocol for Assay and
8234 Certification of Gaseous Calibration Standards", September 1997, EPA-600/R-
8235 97/121 or such revised procedure as approved by the Administrator (EPA
8236 Traceability Protocol).
- 8237
- 8238 b) An EPA Protocol Gas must have a specialty gas producer-certified uncertainty
8239 (95 percent confidence interval) that must not be greater than 2.0 percent of the
8240 certified concentration (tag value) of the gas mixture. The uncertainty must be
8241 calculated using the statistical procedures (or equivalent statistical techniques)
8242 that are listed in Section 2.1.8 of the EPA Traceability Protocol.
- 8243
- 8244 c) A copy of EPA-600/R-97/121 is available from the National Technical
8245 Information Service, 5285 Port Royal Road, Springfield VA, 703-605-6585 or
8246 <http://www.ntis.gov>, and from <http://www.epa.gov/ttn/emc/news.html> or [http://](http://www.epa.gov/appcdwww/tsb/index.html)
8247 www.epa.gov/appcdwww/tsb/index.html.
- 8248

8249 5.1.5 Research Gas Mixtures

8250

8251 Research gas mixtures must be vendor-certified to be within 2.0 percent of the concentration
8252 specified on the cylinder label (tag value), using the uncertainty calculation procedure in Section
8253 2.1.8 of the "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration
8254 Standards", September 1997, EPA-600/R-97/121. Inquiries about the RGM program should be
8255 directed to: National Institute of Standards and Technology, Analytical Chemistry Division,
8256 Chemical Science and Technology Laboratory, B-324 Chemistry, Gaithersburg MD 20899.

8257

8258 5.1.6 Zero Air Material

8259

8260 Zero air material is defined in 40 CFR 72.2, incorporated by reference in Section 225.140.

8261

8262 5.1.7 NIST/EPA-Approved Certified Reference Materials

8263

8264 Existing certified reference materials (CRMs) that are still within their certification period may
8265 be used as calibration gas.

8266

8267 5.1.8 Gas Manufacturer's Intermediate Standards

8268

8269 Gas manufacturer's intermediate standards is defined in 40 CFR 72.2, incorporated by reference
8270 in Section 225.140.

8271

8272 5.1.9 Mercury Standards

8273

8274 For 7-day calibration error tests of mercury concentration monitors and for daily calibration error

8275 tests of mercury monitors, either NIST-traceable elemental mercury standards (as defined in
8276 Section 225.130) or a NIST-traceable source of oxidized mercury (as defined in Section
8277 225.130) may be used. For linearity checks, NIST-traceable elemental mercury standards must
8278 be used. For 3-level and single-point system integrity checks under Section 1.4(c)(1)(E) of this
8279 Appendix, Sections 6.2(g) and 6.3.1 of this Exhibit, and Sections 2.1.1, 2.2.1 and 2.6 of Exhibit
8280 B to this Appendix, a NIST-traceable source of oxidized mercury must be used. Alternatively,
8281 other NIST-traceable standards may be used for the required checks, subject to the approval of
8282 the Agency. Notwithstanding these requirements, mercury calibration standards that are not
8283 NIST-traceable may be used for the tests described in this Section until December 31, 2009.
8284 However, on and after January 1, 2010, only NIST-traceable calibration standards must be used
8285 for these tests.

8286 5.2 Concentrations

8287
8288
8289 Four concentration levels are required as follows.

8290 5.2.1 Zero-level Concentration

8291
8292
8293 0.0 to 20.0 percent of span, including span for high-scale or both low- and high-scale for CO₂
8294 and O₂ monitors, as appropriate.

8295 5.2.2 Low-level Concentration

8296
8297
8298 20.0 to 30.0 percent of span, including span for high-scale or both low- and high-scale for CO₂
8299 and O₂ monitors, as appropriate.

8300 5.2.3 Mid-level Concentration

8301
8302
8303 50.0 to 60.0 percent of span, including span for high-scale or both low- and high-scale for CO₂
8304 and O₂ monitors, as appropriate.

8305 5.2.4 High-level Concentration

8306
8307
8308 80.0 to 100.0 percent of span, including span for high-scale or both low-and high-scale for CO₂
8309 and O₂ monitors, as appropriate.

8310 6. Certification Tests and Procedures

8311 6.1 General Requirements

8312 6.1.1 Pretest Preparation

8313
8314
8315
8316
8317 Install the components of the continuous emission monitoring system (i.e., pollutant

8318 concentration monitors, CO₂ or O₂ monitor, and flow monitor) as specified in Sections 1, 2, and
 8319 3 of this Exhibit, and prepare each system component and the combined system for operation in
 8320 accordance with the manufacturer's written instructions. Operate the units during each period
 8321 when measurements are made. Units may be tested on non-consecutive days. To the extent
 8322 practicable, test the DAHS software prior to testing the monitoring hardware.

8323
 8324 6.1.2 Requirements for Air Emission Testing Bodies

- 8325
- 8326 a) On and after January 1, 2009, any Air Emission Testing Body (AETB) conducting
 8327 relative accuracy test audits of CEMS and sorbent trap monitoring systems under
 8328 Part 225, Subpart B, must conform to the requirements of ASTM D7036-04
 8329 (incorporated by reference in Section 225.140). This Section is not applicable to
 8330 daily operation, daily calibration error checks, daily flow interference checks,
 8331 quarterly linearity checks or routine maintenance of CEMS.
- 8332
- 8333 b) The AETB must provide to the affected sources certification that the AETB
 8334 operates in conformance with, and that data submitted to the Agency has been
 8335 collected in accordance with, the requirements of ASTM D7036-04 (incorporated
 8336 by reference in Section 225.140). This certification may be provided in the form
 8337 of:
- 8338
- 8339 1) A certificate of accreditation of relevant scope issued by a recognized,
 8340 national accreditation body; or
- 8341
- 8342 2) A letter of certification signed by a member of the senior management
 8343 staff of the AETB.
- 8344
- 8345 c) The AETB must either provide a Qualified Individual on-site to conduct or must
 8346 oversee all relative accuracy testing carried out by the AETB as required in
 8347 ASTM D7036-04 (incorporated by reference in Section 225.140). The Qualified
 8348 Individual must provide the affected sources with copies of the qualification
 8349 credentials relevant to the scope of the testing conducted.

8350

8351 6.2 Linearity Check (General Procedures)

8352

8353 Check the linearity of each CO₂, Hg, and O₂ monitor while the unit, or group of units for a
 8354 common stack, is combusting fuel at conditions of typical stack temperature and pressure; it is
 8355 not necessary for the unit to be generating electricity during this test. For units with two
 8356 measurement ranges (high and low) for a particular parameter, perform a linearity check on both
 8357 the low scale and the high scale. For on-going quality assurance of the CEMS, perform linearity
 8358 checks, using the procedures in this Section, on the ranges and at the frequency specified in
 8359 Section 2.2.1 of Exhibit B to this Appendix. Challenge each monitor with calibration gas, as
 8360 defined in Section 5.1 of this Exhibit, at the low-, mid-, and high-range concentrations specified

8361 in Section 5.2 of this Exhibit. Introduce the calibration gas at the gas injection port, as specified
 8362 in Section 2.2.1 of this Exhibit. Operate each monitor at its normal operating temperature and
 8363 conditions. For extractive and dilution type monitors, pass the calibration gas through all filters,
 8364 scrubbers, conditioners, and other monitor components used during normal sampling and
 8365 through as much of the sampling probe as is practical. For in-situ type monitors, perform
 8366 calibration checking all active electronic and optical components, including the transmitter,
 8367 receiver, and analyzer. Challenge the monitor three times with each reference gas (see example
 8368 data sheet in Figure 1). Do not use the same gas twice in succession. To the extent practicable,
 8369 the duration of each linearity test, from the hour of the first injection to the hour of the last
 8370 injection, must not exceed 24 unit operating hours. Record the monitor response from the data
 8371 acquisition and handling system. For each concentration, use the average of the responses to
 8372 determine the error in linearity using Equation A-4 in this Exhibit. Linearity checks are
 8373 acceptable for monitor or monitoring system certification, recertification, or quality assurance if
 8374 none of the test results exceed the applicable performance specifications in Section 3.2 of this
 8375 Exhibit. The status of emission data from a CEMS prior to and during a linearity test period must
 8376 be determined as follows:

- 8377
- 8378 a) For the initial certification of a CEMS, data from the monitoring system are
 8379 considered invalid until all certification tests, including the linearity test, have
 8380 been successfully completed, unless the conditional data validation procedures in
 8381 Section 1.4(b)(3) of this Appendix are used. When the procedures in Section
 8382 1.4(b)(3) of this Appendix are followed, the words "initial certification" apply
 8383 instead of "recertification", and complete all of the initial certification tests by
 8384 January 1, 2009, rather than within the time periods specified in Section
 8385 1.4(b)(3)(D) of this Appendix for the individual tests.
- 8386
- 8387 b) For the routine quality assurance linearity checks required by Section 2.2.1 of
 8388 Exhibit B to this Appendix, use the data validation procedures in Section 2.2.3 of
 8389 Exhibit B to this Appendix.
- 8390
- 8391 c) When a linearity test is required as a diagnostic test or for recertification, use the
 8392 data validation procedures in Section 1.4 (b)(3) of this Appendix.
- 8393
- 8394 d) For linearity tests of non-redundant backup monitoring systems, use the data
 8395 validation procedures in Section 1.4(d)(2)(C) of this Appendix.
- 8396
- 8397 e) For linearity tests performed during a grace period and after the expiration of a
 8398 grace period, use the data validation procedures in Sections 2.2.3 and 2.2.4,
 8399 respectively, of Exhibit B to this Appendix.
- 8400
- 8401 f) For all other linearity checks, use the data validation procedures in Section 2.2.3
 8402 of Exhibit B to this Appendix.
- 8403

- 8404 g) For mercury monitors, follow the guidelines in Section 2.2.3 of this Exhibit in
 8405 addition to the applicable procedures in Section 6.2 when performing the system
 8406 integrity checks described in Section 1.4(c)(1)(E) and in Sections 2.1.1, 2.2.1, and
 8407 2.6 of Exhibit B to this Appendix.
- 8408
- 8409 h) For mercury concentration monitors, if moisture is added to the calibration gas
 8410 during the required linearity checks or system integrity checks, the moisture
 8411 content of the calibration gas must be accounted for. Under these circumstances,
 8412 the dry basis concentration of the calibration gas must be used to calculate the
 8413 linearity error or measurement error (as applicable).

8414

8415 6.3 7-Day Calibration Error Test

8416

8417 6.3.1 Gas Monitor 7-day Calibration Error Test

8418

8419 Measure the calibration error of each mercury concentration monitor and each CO₂ or O₂
 8420 monitor while the unit is combusting fuel (but not necessarily generating electricity) once each
 8421 day for 7 consecutive operating days according to the following procedures. For mercury
 8422 monitors, you may perform this test using either elemental mercury standards or a NIST-
 8423 traceable source of oxidized mercury. Also for mercury monitors, if moisture is added to the
 8424 calibration gas, the added moisture must be accounted for and the dry-basis concentration of the
 8425 calibration gas must be used to calculate the calibration error. (In the event that unit outages
 8426 occur after the commencement of the test, the 7 consecutive unit operating days need not be 7
 8427 consecutive calendar days.) Units using dual span monitors must perform the calibration error
 8428 test on both high- and low-scales of the pollutant concentration monitor. The calibration error
 8429 test procedures in this Section and in Section 6.3.2 of this Exhibit must also be used to perform
 8430 the daily assessments and additional calibration error tests required under Sections 2.1.1 and
 8431 2.1.3 of Exhibit B to this Appendix. Do not make manual or automatic adjustments to the
 8432 monitor settings until after taking measurements at both zero and high concentration levels for
 8433 that day during the 7-day test. If automatic adjustments are made following both injections,
 8434 conduct the calibration error test such that the magnitude of the adjustments can be determined
 8435 and recorded. Record and report test results for each day using the unadjusted concentration
 8436 measured in the calibration error test prior to making any manual or automatic adjustments (i.e.,
 8437 resetting the calibration). The calibration error tests should be approximately 24 hours apart,
 8438 (unless the 7-day test is performed over non-consecutive days). Perform calibration error tests at
 8439 both the zero-level concentration and high-level concentration, as specified in Section 5.2 of this
 8440 Exhibit. Alternatively, a mid-level concentration gas (50.0 to 60.0 percent of the span value) may
 8441 be used in lieu of the high-level gas, provided that the mid-level gas is more representative of the
 8442 actual stack gas concentrations. Use only calibration gas, as specified in Section 5.1 of this
 8443 Exhibit. Introduce the calibration gas at the gas injection port, as specified in Section 2.2.1 of this
 8444 Exhibit. Operate each monitor in its normal sampling mode. For extractive and dilution type
 8445 monitors, pass the calibration gas through all filters, scrubbers, conditioners, and other monitor
 8446 components used during normal sampling and through as much of the sampling probe as is

8447 practical. For in-situ type monitors, perform calibration, checking all active electronic and
 8448 optical components, including the transmitter, receiver, and analyzer. Challenge the pollutant
 8449 concentration monitors and CO₂ or O₂ monitors once with each calibration gas. Record the
 8450 monitor response from the data acquisition and handling system. Using Equation A-5 of this
 8451 Exhibit, determine the calibration error at each concentration once each day (at approximately
 8452 24-hour intervals) for 7 consecutive days according to the procedures given in this Section. The
 8453 results of a 7-day calibration error test are acceptable for monitor or monitoring system
 8454 certification, recertification or diagnostic testing if none of these daily calibration error test
 8455 results exceed the applicable performance specifications in Section 3.1 of this Exhibit. The status
 8456 of emission data from a gas monitor prior to and during a 7-day calibration error test period must
 8457 be determined as follows:

- 8458
- 8459 a) For initial certification, data from the monitor are considered invalid until all
 8460 certification tests, including the 7-day calibration error test, have been
 8461 successfully completed, unless the conditional data validation procedures in
 8462 Section 1.4(b)(3) of this Appendix are used. When the procedures in Section
 8463 1.4(b)(3) of this Appendix are followed, the words "initial certification" apply
 8464 instead of "recertification", and complete all of the initial certification tests by
 8465 January 1, 2009, rather than within the time periods specified in Section
 8466 1.4(b)(3)(D) of this Appendix for the individual tests.
 - 8467
 - 8468 b) When a 7-day calibration error test is required as a diagnostic test or for
 8469 recertification, use the data validation procedures in Section 1.4(b)(3) of this
 8470 Appendix.

8471

8472 6.3.2 Flow Monitor 7-day Calibration Error Test

8473

8474 Flow monitors installed on peaking units (as defined in 40 CFR 72.2, incorporated by reference
 8475 in Section 225.140) are exempted from the 7-day calibration error test requirements of this part.
 8476 In all other cases, perform the 7-day calibration error test of a flow monitor, when required for
 8477 certification, recertification or diagnostic testing, according to the following procedures.
 8478 Introduce the reference signal corresponding to the values specified in Section 2.2.2.1 of this
 8479 Exhibit to the probe tip (or equivalent), or to the transducer. During the 7-day certification test
 8480 period, conduct the calibration error test while the unit is operating once each unit operating day
 8481 (as close to 24-hour intervals as practicable). In the event that unit outages occur after the
 8482 commencement of the test, the 7 consecutive operating days need not be 7 consecutive calendar
 8483 days. Record the flow monitor responses by means of the data acquisition and handling system.
 8484 Calculate the calibration error using Equation A-6 of this Exhibit. Do not perform any corrective
 8485 maintenance, repair, or replacement upon the flow monitor during the 7-day test period other
 8486 than that required in the quality assurance/quality control plan required by Exhibit B to this
 8487 Appendix. Do not make adjustments between the zero and high reference level measurements on
 8488 any day during the 7-day test. If the flow monitor operates within the calibration error
 8489 performance specification (i.e., less than or equal to 3.0 percent error each day and requiring no

8490 corrective maintenance, repair, or replacement during the 7-day test period), the flow monitor
 8491 passes the calibration error test. Record all maintenance activities and the magnitude of any
 8492 adjustments. Record output readings from the data acquisition and handling system before and
 8493 after all adjustments. Record and report all calibration error test results using the unadjusted flow
 8494 rate measured in the calibration error test prior to resetting the calibration. Record all
 8495 adjustments made during the 7-day period at the time the adjustment is made, and report them in
 8496 the certification or recertification application. The status of emissions data from a flow monitor
 8497 prior to and during a 7-day calibration error test period must be determined as follows:

8498
 8499 a) For initial certification, data from the monitor are considered invalid until all
 8500 certification tests, including the 7-day calibration error test, have been
 8501 successfully completed, unless the conditional data validation procedures in
 8502 Section 1.4(b)(3) of this Appendix are used. When the procedures in Section
 8503 1.4(b)(3) of this Appendix are followed, the words "initial certification" apply
 8504 instead of "recertification", and complete all of the initial certification tests by
 8505 January 1, 2009, rather than within the time periods specified in Section
 8506 1.4(b)(3)(D) of this Appendix for the individual tests.

8507
 8508 b) When a 7-day calibration error test is required as a diagnostic test or for
 8509 recertification, use the data validation procedures in Section 1.4(b)(3).
 8510

8511
$$CE = \frac{|R - A|}{S} \times 100 \quad \text{(Equation A-6)}$$

8512
 8513 Where:

- 8514
- CE = Calibration error as a percentage of span.
 - R = Low or high level reference value specified in Section 2.2.2.1 of this Exhibit.
 - A = Actual flow monitor response to the reference value.
 - S = Flow monitor calibration span value as determined under Section 2.1.2.2 of this Exhibit.

8515
 8516 6.3.3
 8517

8518 For gas or flow monitors installed on peaking units, the exemption from performing the 7-day
 8519 calibration error test applies as long as the unit continues to meet the definition of a peaking unit
 8520 in 40 CFR 72.2, incorporated by reference in Section 225.140. However, if at the end of a
 8521 particular calendar year or ozone season, it is determined that peaking unit status has been lost,
 8522 the owner or operator must perform a diagnostic 7-day calibration error test of each monitor
 8523 installed on the unit, by no later than December 31 of the following calendar year.

6.4 Cycle Time Test

Perform cycle time tests for each pollutant concentration monitor and continuous emission monitoring system while the unit is operating, according to the following procedures. Use a zero-level and a high-level calibration gas (as defined in Section 5.2 of this Exhibit) alternately. For mercury monitors, the calibration gas used for this test may either be the elemental or oxidized form of mercury. To determine the downscale cycle time, measure the concentration of the flue gas emissions until the response stabilizes. Record the stable emissions value. Inject a zero-level concentration calibration gas into the probe tip (or injection port leading to the calibration cell, for in-situ systems with no probe). Record the time of the zero gas injection, using the data acquisition and handling system (DAHS). Next, allow the monitor to measure the concentration of the zero gas until the response stabilizes. Record the stable ending calibration gas reading. Determine the downscale cycle time as the time it takes for 95.0 percent of the step change to be achieved between the stable stack emissions value and the stable ending zero gas reading. Then repeat the procedure, starting with stable stack emissions and injecting the high-level gas, to determine the upscale cycle time, which is the time it takes for 95.0 percent of the step change to be achieved between the stable stack emissions value and the stable ending high-level gas reading. Use the following criteria to assess when a stable reading of stack emissions or calibration gas concentration has been attained. A stable value is equivalent to a reading with a change of less than 2.0 percent of the span value for 2 minutes, or a reading with a change of less than 6.0 percent from the measured average concentration over 6 minutes. Alternatively, the reading is considered stable if it changes by no more than 0.5 ppm, 0.5 $\mu\text{g}/\text{m}^3$ (for mercury) for two minutes. (Owners or operators of systems that do not record data in 1-minute or 3-minute intervals may petition the Agency for alternative stabilization criteria). For monitors or monitoring systems that perform a series of operations (such as purge, sample, and analyze), time the injections of the calibration gases so they will produce the longest possible cycle time. Refer to Figures 6a and 6b in this Exhibit for example calculations of upscale and downscale cycle times. Report the slower of the two cycle times (upscale or downscale) as the cycle time for the analyzer. On and after January 1, 2009, record the cycle time for each component analyzer separately. For time-shared systems, perform the cycle time tests at each of the probe locations that will be polled within the same 15-minute period during monitoring system operations. To determine the cycle time for time-shared systems, at each monitoring location, report the sum of the cycle time observed at that monitoring location plus the sum of the time required for all purge cycles (as determined by the continuous emission monitoring system manufacturer) at each of the probe locations of the time-shared systems. For monitors with dual ranges, report the test results for each range separately. Cycle time test results are acceptable for monitor or monitoring system certification, recertification or diagnostic testing if none of the cycle times exceed 15 minutes. The status of emissions data from a monitor prior to and during a cycle time test period must be determined as follows:

- a) For initial certification, data from the monitor are considered invalid until all certification tests, including the cycle time test, have been successfully completed,

8567 unless the conditional data validation procedures in Section 1.4(b)(3) of this
 8568 Appendix are used. When the procedures in Section 1.4(b)(3) of this Appendix
 8569 are followed, the words "initial certification" apply instead of "recertification",
 8570 and complete all of the initial certification tests by January 1, 2009, rather than
 8571 within the time periods specified in Section 1.4(b)(3)(D) of this Appendix for the
 8572 individual tests.

8573
 8574 b) When a cycle time test is required as a diagnostic test or for recertification, use
 8575 the data validation procedures in Section 1.4(b)(3) of this Appendix.
 8576

8577 6.5 Relative Accuracy and Bias Tests (General Procedures)
 8578

8579 Perform the required relative accuracy test audits (RATAs) as follows for each flow monitor,
 8580 each O₂ or CO₂ diluent monitor used to calculate heat input, each mercury concentration
 8581 monitoring system, each sorbent trap monitoring system, and each moisture monitoring system.
 8582

8583 a) Except as otherwise provided in this subsection, perform each RATA while the
 8584 unit (or units, if more than one unit exhausts into the flue) is combusting the fuel
 8585 that is a normal primary or backup fuel for that unit (for some units, more than
 8586 one type of fuel may be considered normal, e.g., a unit that combusts gas or oil on
 8587 a seasonal basis). For units that co-fire fuels as the predominant mode of
 8588 operation, perform the RATAs while co-firing. For mercury monitoring systems,
 8589 perform the RATAs while the unit is combusting coal. When relative accuracy
 8590 test audits are performed on CEMS installed on bypass stacks/ducts, use the fuel
 8591 normally combusted by the unit (or units, if more than one unit exhausts into the
 8592 flue) when emissions exhaust through the bypass stack/ducts.
 8593

8594 b) Perform each RATA at the load (or operating) levels specified in Section 6.5.1 or
 8595 6.5.2 of this Exhibit or in Section 2.3.1.3 of Exhibit B to this Appendix, as
 8596 applicable.
 8597

8598 c) For monitoring systems with dual ranges, perform the relative accuracy test on the
 8599 range normally used for measuring emissions. For units with add-on mercury
 8600 controls that operate continuously rather than seasonally, or for units that need a
 8601 dual range to record high concentration "spikes" during startup conditions, the
 8602 low range is considered normal. However, for some dual span units (e.g., for units
 8603 that use fuel switching or for which the emission controls are operated
 8604 seasonally), provided that both monitor ranges are connected to a common probe
 8605 and sample interface, either of the two measurement ranges may be considered
 8606 normal; in such cases, perform the RATA on the range that is in use at the time of
 8607 the scheduled test. If the low and high measurement ranges are connected to
 8608 separate sample probes and interfaces, RATA testing on both ranges is required.
 8609

- 8610 d) Record monitor or monitoring system output from the data acquisition and
 8611 handling system.
- 8612
- 8613 e) Complete each single-load relative accuracy test audit within a period of 168
 8614 consecutive unit operating hours, as defined in 40 CFR 72.2, incorporated by
 8615 reference in Section 225.140 (or, for CEMS installed on common stacks or bypass
 8616 stacks, 168 consecutive stack operating hours, as defined in 40 CFR 72.2,
 8617 incorporated by reference in Section 225.140). Notwithstanding this requirement,
 8618 up to 336 consecutive unit or stack operating hours may be taken to complete the
 8619 RATA of a mercury monitoring system, when ASTM 6784-02 (incorporated by
 8620 reference in Section 225.140) or Method 29 in appendix A-8 to 40 CFR 60,
 8621 incorporated by reference in Section 225.140, is used as the reference method. For
 8622 2-level and 3-level flow monitor RATAs, complete all of the RATAs at all levels,
 8623 to the extent practicable, within a period of 168 consecutive unit (or stack)
 8624 operating hours; however, if this is not possible, up to 720 consecutive unit (or
 8625 stack) operating hours may be taken to complete a multiple-load flow RATA.
 8626
- 8627 f) The status of emission data from the CEMS prior to and during the RATA test
 8628 period must be determined as follows:
- 8629
- 8630 1) For the initial certification of a CEMS, data from the monitoring system
 8631 are considered invalid until all certification tests, including the RATA,
 8632 have been successfully completed, unless the conditional data validation
 8633 procedures in Section 1.4(b)(3) of this Appendix are used. When the
 8634 procedures in Section 1.4(b)(3) of this Appendix are followed, the words
 8635 "initial certification" apply instead of "recertification", and complete all of
 8636 the initial certification tests by January 1, 2009, rather than within the time
 8637 periods specified in Section 1.4(b)(3)(D) of this Appendix for the
 8638 individual tests.
- 8639
- 8640 2) For the routine quality assurance RATAs required by Section 2.3.1 of
 8641 Exhibit B to this Appendix, use the data validation procedures in Section
 8642 2.3.2 of Exhibit B to this Appendix.
- 8643
- 8644 3) For recertification RATAs, use the data validation procedures in Section
 8645 1.4(b)(3).
- 8646
- 8647 4) For quality assurance RATAs of non-redundant backup monitoring
 8648 systems, use the data validation procedures in Section 1.4(d)(2)(D) and (E)
 8649 of this Appendix.
- 8650
- 8651 5) For RATAs performed during and after the expiration of a grace period,
 8652 use the data validation procedures in Sections 2.3.2 and 2.3.3,

8653 respectively, of Exhibit B to this Appendix.

8654
 8655 6) For all other RATAs, use the data validation procedures in Section 2.3.2
 8656 of Exhibit B to this Appendix.

8657
 8658 g) For each flow monitor, each CO₂ or O₂ diluent monitor used to determine heat
 8659 input, each moisture monitoring system, each mercury concentration monitoring
 8660 system, and each sorbent trap monitoring system, calculate the relative accuracy,
 8661 in accordance with Section 7.3 of this Exhibit, as applicable.

8662
 8663 6.5.1 Gas and Mercury Monitoring System RATAs (Special Considerations)

8664
 8665 a) Perform the required relative accuracy test audits for each CO₂ or O₂ diluent
 8666 monitor used to determine heat input, each mercury concentration monitoring
 8667 system, and each sorbent trap monitoring system at the normal load level or
 8668 normal operating level for the unit (or combined units, if common stack), as
 8669 defined in Section 6.5.2.1 of this Exhibit. If two load levels or operating levels
 8670 have been designated as normal, the RATAs may be done at either load level.

8671
 8672 b) For the initial certification of a gas or mercury monitoring system and for
 8673 recertifications in which, in addition to a RATA, one or more other tests are
 8674 required (i.e., a linearity test, cycle time test, or 7-day calibration error test), the
 8675 Agency recommends that the RATA not be commenced until the other required
 8676 tests of the CEMS have been passed.

8677
 8678 6.5.2 Flow Monitor RATAs (Special Considerations)

8679
 8680 a) Except as otherwise provided in subsection (b) or (e) of this Section, perform
 8681 relative accuracy test audits for the initial certification of each flow monitor at
 8682 three different exhaust gas velocities (low, mid, and high), corresponding to three
 8683 different load levels or operating levels within the range of operation, as defined
 8684 in Section 6.5.2.1 of this Exhibit. For a common stack/duct, the three different
 8685 exhaust gas velocities may be obtained from frequently used unit/load or
 8686 operating level combinations for the units exhausting to the common stack. Select
 8687 the three exhaust gas velocities such that the audit points at adjacent load or
 8688 operating levels (i.e., low and mid or mid and high), in megawatts (or in
 8689 thousands of lb/hr of steam production or in ft/sec, as applicable), are separated
 8690 by no less than 25.0 percent of the range of operation, as defined in Section
 8691 6.5.2.1 of this Exhibit.

8692
 8693 b) For flow monitors on bypass stacks/ducts and peaking units, the flow monitor
 8694 relative accuracy test audits for initial certification and recertification must be
 8695 single-load tests, performed at the normal load, as defined in Section 6.5.2.1(d) of

8696 this Exhibit.

8697

8698 c) Flow monitor recertification RATAs must be done at three load levels (or three
8699 operating levels), unless otherwise specified in subsection (b) or (e) of this
8700 Section or unless otherwise specified or approved by the Agency.

8701

8702 d) The semiannual and annual quality assurance flow monitor RATAs required
8703 under Exhibit B to this Appendix must be done at the load levels (or operating
8704 levels) specified in Section 2.3.1.3 of Exhibit B to this Appendix.

8705

8706 e) For flow monitors installed on units that do not produce electrical or thermal
8707 output, the flow RATAs for initial certification or recertification may be done at
8708 fewer than three operating levels, if:

8709

8710 1) The owner or operator provides a technical justification in the hardcopy
8711 portion of the monitoring plan for the unit required under 40 CFR
8712 75.53(e)(2), incorporated by reference in Section 225.140, demonstrating
8713 that the unit operates at only one level or two levels during normal
8714 operation (excluding unit startup and shutdown). Appropriate
8715 documentation and data must be provided to support the claim of single-
8716 level or two-level operation; and

8717

8718 2) The justification provided in subsection (e)(1) of this Section is deemed to
8719 be acceptable by the permitting authority.

8720

8721 6.5.2.1 Range of Operation and Normal Load (or Operating) Levels

8722

8723 a) The owner or operator must determine the upper and lower boundaries of the
8724 "range of operation" as follows for each unit (or combination of units, for
8725 common stack configurations):

8726

8727 1) For affected units that produce electrical output (in megawatts) or thermal
8728 output (in lb/hr of steam production or mmBtu/hr), the lower boundary of
8729 the range of operation of a unit must be the minimum safe, stable loads for
8730 any of the units discharging through the stack. Alternatively, for a group
8731 of frequently operated units that serve a common stack, the sum of the
8732 minimum safe, stable loads for the individual units may be used as the
8733 lower boundary of the range of operation. The upper boundary of the
8734 range of operation of a unit must be the maximum sustainable load. The
8735 "maximum sustainable load" is the higher of either: the nameplate or rated
8736 capacity of the unit, less any physical or regulatory limitations or other
8737 deratings; or the highest sustainable load, based on at least four quarters of
8738 representative historical operating data. For common stacks, the maximum

8739 sustainable load is the sum of all of the maximum sustainable loads of the
 8740 individual units discharging through the stack, unless this load is
 8741 unattainable in practice, in which case use the highest sustainable
 8742 combined load for the units that discharge through the stack. Based on at
 8743 least four quarters of representative historical operating data. The load
 8744 values for the units must be expressed either in units of megawatts of
 8745 thousands of lb/hr of steam load or mmBtu/hr of thermal output; or
 8746

8747 2) For affected units that do not produce electrical or thermal output, the
 8748 lower boundary of the range of operation must be the minimum expected
 8749 flue gas velocity (in ft/sec) during normal, stable operation of the unit. The
 8750 upper boundary of the range of operation must be the maximum potential
 8751 flue gas velocity (in ft/sec) as defined in Section 2.1.2.1 of this Exhibit.
 8752 The minimum expected and maximum potential velocities may be derived
 8753 from the results of reference method testing or by using Equation A-3a or
 8754 A-3b (as applicable) in Section 2.1.2.1 of this Exhibit. If Equation A-3a or
 8755 A-3b is used to determine the minimum expected velocity, replace the
 8756 word "maximum" with the word "minimum" in the definitions of "MPV,"
 8757 "H_f," "%O_{2d}", and "%H₂O", and replace the word "minimum" with the
 8758 word "maximum" in the definition of "CO_{2d}". Alternatively, 0.0 ft/sec may
 8759 be used as the lower boundary of the range of operation.
 8760

8761 b) The operating levels for relative accuracy test audits will, except for peaking
 8762 units, be defined as follows: the "low" operating level will be the first 30.0
 8763 percent of the range of operation; the "mid" operating level will be the middle
 8764 portion (> 30.0 percent, but ≤ 60.0 percent) of the range of operation; and the
 8765 "high" operating level will be the upper end (> 60.0 percent) of the range of
 8766 operation. For example, if the upper and lower boundaries of the range of
 8767 operation are 100 and 1100 megawatts, respectively, then the low, mid, and high
 8768 operating levels would be 100 to 400 megawatts, 400 to 700 megawatts, and 700
 8769 to 1100 megawatts, respectively.
 8770

8771 c) Units that do not produce electrical or thermal output are exempted from the
 8772 requirements of this subsection (c). The owner or operator must identify, for each
 8773 affected unit or common stack, the "normal" load level or levels (low, mid or
 8774 high), based on the operating history of the units. To identify the normal load
 8775 levels, the owner or operator must, at a minimum, determine the relative number
 8776 of operating hours at each of the three load levels, low, mid and high over the past
 8777 four representative operating quarters. The owner or operator must determine, to
 8778 the nearest 0.1 percent, the percentage of the time that each load level (low, mid,
 8779 high) has been used during that time period. A summary of the data used for this
 8780 determination and the calculated results must be kept on-site in a format suitable
 8781 for inspection. For new units or newly affected units, the data analysis in this

8782 subsection may be based on fewer than four quarters of data if fewer than four
 8783 representative quarters of historical load data are available. Or, if no historical
 8784 load data are available, the owner or operator may designate the normal load
 8785 based on the expected or projected manner of operating the unit. However, in
 8786 either case, once four quarters of representative data become available, the
 8787 historical load analysis must be repeated.

8788
 8789 d) Determination of normal load (or operating level)
 8790

8791 1) Based on the analysis of the historical load data described in subsection (c)
 8792 of this Section, the owner or operator must, for units that produce
 8793 electrical or thermal output, designate the most frequently used load level
 8794 as the normal load level for the unit (or combination of units, for common
 8795 stacks). The owner or operator may also designate the second most
 8796 frequently used load level as an additional normal load level for the unit or
 8797 stack. If the manner of operation of the unit changes significantly, such
 8798 that the designated normal loads or the two most frequently used load
 8799 levels change, the owner or operator must repeat the historical load
 8800 analysis and must redesignate the normal loads and the two most
 8801 frequently used load levels, as appropriate. A minimum of two
 8802 representative quarters of historical load data are required to document
 8803 that a change in the manner of unit operation has occurred. Update the
 8804 electronic monitoring plan whenever the normal load levels and the two
 8805 most frequently used load levels are redesignated.

8806
 8807 2) For units that do not produce electrical or thermal output, the normal
 8808 operating levels must be determined using sound engineering judgment,
 8809 based on knowledge of the unit and operating experience with the
 8810 industrial process.

8811
 8812 e) The owner or operator must report the upper and lower boundaries of the range of
 8813 operation for each unit (or combination of units, for common stacks), in units of
 8814 megawatts or thousands of lb/hr or mmBtu/hr of steam production or ft/sec (as
 8815 applicable), in the electronic monitoring plan required under Section 1.10 of this
 8816 Appendix.

8817
 8818 6.5.2.2 Multi-Load (or Multi-Level) Flow RATA Results
 8819

8820 For each multi-load (or multi-level) flow RATA, calculate the flow monitor relative accuracy at
 8821 each operating level. If a flow monitor relative accuracy test is failed or aborted due to a problem
 8822 with the monitor on any level of a 2-level (or 3-level) relative accuracy test audit, the RATA
 8823 must be repeated at that load (or operating) level. However, the entire 2-level (or 3-level) relative
 8824 accuracy test audit does not have to be repeated unless the flow monitor polynomial coefficients

8825 or K-factors are changed, in which case a 3-level RATA is required (or, a 2-level RATA, for
 8826 units demonstrated to operate at only two levels, under Section 6.5.2(e) of this Exhibit).

8827
 8828 6.5.3 Calculations
 8829

8830 Using the data from the relative accuracy test audits, calculate relative accuracy and bias in
 8831 accordance with the procedures and equations specified in Section 7 of this Exhibit.

8832
 8833 6.5.4 Reference Method Measurement Location
 8834

8835 Select a location for reference method measurements that is (1) accessible; (2) in the same
 8836 proximity as the monitor or monitoring system location; and (3) meets the requirements of
 8837 Performance Specification 3 in appendix B of 40 CFR 60, incorporated by reference in Section
 8838 225.140, for CO₂ or O₂ monitors, or Method 1 (or 1A) in appendix A of 40 CFR 60, incorporated
 8839 by reference in Section 225.140, for volumetric flow, except as otherwise indicated in this
 8840 Section or as approved by the Agency.

8841
 8842 6.5.5 Reference Method Traverse Point Selection
 8843

8844 Select traverse points that ensure acquisition of representative samples of pollutant and diluent
 8845 concentrations, moisture content, temperature, and flue gas flow rate over the flue cross Section.
 8846 To achieve this, the reference method traverse points must meet the requirements of Section
 8847 8.1.3 of Performance Specification 2 ("PS No. 2") in appendix B to 40 CFR 60, incorporated by
 8848 reference in Section 225.140 (for moisture monitoring system RATAs), Performance
 8849 Specification 3 in appendix B to 40 CFR 60, incorporated by reference in Section 225.140 (for
 8850 O₂ and CO₂ monitor RATAs), Method 1 (or 1A) (for volumetric flow rate monitor RATAs),
 8851 Method 3 (for molecular weight), and Method 4 (for moisture determination) in appendix A to
 8852 40 CFR 60, incorporated by reference in Section 225.140. The following alternative reference
 8853 method traverse point locations are permitted for moisture and gas monitor RATAs:

- 8854
 8855 a) For moisture determinations where the moisture data are used only to determine
 8856 stack gas molecular weight, a single reference method point, located at least 1.0
 8857 meter from the stack wall, may be used. For moisture monitoring system RATAs
 8858 and for gas monitor RATAs in which moisture data are used to correct pollutant
 8859 or diluent concentrations from a dry basis to a wet basis (or vice-versa), single-
 8860 point moisture sampling may only be used if the 12-point stratification test
 8861 described in Section 6.5.5.1 of this Exhibit is performed prior to the RATA for at
 8862 least one pollutant or diluent gas, and if the test is passed according to the
 8863 acceptance criteria in Section 6.5.5.3(b) of this Exhibit.
 8864
 8865 b) For gas monitoring system RATAs, the owner or operator may use any of the
 8866 following options:
 8867

- 8868 1) At any location (including locations where stratification is expected), use a
 8869 minimum of six traverse points along a diameter, in the direction of any
 8870 expected stratification. The points must be located in accordance with
 8871 Method 1 in appendix A to 40 CFR 60, incorporated by reference in
 8872 Section 225.140.
- 8873
- 8874 2) At locations where Section 8.1.3 of PS No. 2 allows the use of a short
 8875 reference method measurement line (with three points located at 0.4, 1.2,
 8876 and 2.0 meters from the stack wall), the owner or operator may use an
 8877 alternative 3-point measurement line, locating the three points at 4.4, 14.6,
 8878 and 29.6 percent of the way across the stack, in accordance with Method 1
 8879 in appendix A to 40 CFR 60, incorporated by reference in Section
 8880 225.140.
- 8881
- 8882 3) At locations where stratification is likely to occur (e.g., following a wet
 8883 scrubber or when dissimilar gas streams are combined), the short
 8884 measurement line from Section 8.1.3 of PS No. 2 (or the alternative line
 8885 described in subsection (b)(2) of this Section) may be used in lieu of the
 8886 prescribed "long" measurement line in Section 8.1.3 of PS No. 2, provided
 8887 that the 12-point stratification test described in Section 6.5.5.1 of this
 8888 Exhibit is performed and passed one time at the location (according to the
 8889 acceptance criteria of Section 6.5.5.3(a) of this Exhibit) and provided that
 8890 either the 12-point stratification test or the alternative (abbreviated)
 8891 stratification test in Section 6.5.5.2 of this Exhibit is performed and passed
 8892 prior to each subsequent RATA at the location (according to the
 8893 acceptance criteria of Section 6.5.5.3(a) of this Exhibit).
- 8894
- 8895 4) A single reference method measurement point, located no less than 1.0
 8896 meter from the stack wall and situated along one of the measurement lines
 8897 used for the stratification test, may be used at any sampling location if the
 8898 12-point stratification test described in Section 6.5.5.1 of this Exhibit is
 8899 performed and passed prior to each RATA at the location (according to the
 8900 acceptance criteria of Section 6.5.5.3(b) of this Exhibit).
- 8901
- 8902 c) For mercury monitoring systems, use the same basic approach for traverse point
 8903 selection that is used for the other gas monitoring system RATAs, except that the
 8904 stratification test provisions in Sections 8.1.3 through 8.1.3.5 of Method 30A must
 8905 apply, rather than the provisions of Sections 6.5.5.1 through 6.5.5.3 of this
 8906 Exhibit.

8907
 8908 6.5.5.1 Stratification Test
 8909

- 8910 a) With the units operating under steady-state conditions at the normal load level (or

8911 normal operating level), as defined in Section 6.5.2.1 of this Exhibit, use a
 8912 traversing gas sampling probe to measure diluent (CO₂ or O₂) concentrations at a
 8913 minimum of 12 points, located according to Method 1 in appendix A to 40 CFR
 8914 60, incorporated by reference in Section 225.140.

8915
 8916 b) Use Method 3A in appendix A to 40 CFR 60, incorporated by reference in
 8917 Section 225.140, to make the measurements. Data from the reference method
 8918 analyzers must be quality assured by performing analyzer calibration error and
 8919 system bias checks before the series of measurements and by conducting system
 8920 bias and calibration drift checks after the measurements, in accordance with the
 8921 procedures of Method 3A.

8922
 8923 c) Measure for a minimum of 2 minutes at each traverse point. To the extent
 8924 practicable, complete the traverse within a 2-hour period.

8925
 8926 d) If the load has remained constant (± 3.0 percent) during the traverse and if the
 8927 reference method analyzers have passed all of the required quality assurance
 8928 checks, proceed with the data analysis.

8929
 8930 e) Calculate the average CO₂ (or O₂) concentrations at each of the individual
 8931 traverse points. Then, calculate the arithmetic average CO₂ (or O₂) concentrations
 8932 for all traverse points.

8933
 8934 6.5.5.2 Alternative (Abbreviated) Stratification Test

8935
 8936 a) With the units operating under steady-state conditions at the normal load level (or
 8937 normal operating level), as defined in Section 6.5.2.1 of this Exhibit, use a
 8938 traversing gas sampling probe to measure the diluent (CO₂ or O₂) concentrations
 8939 at three points. The points must be located according to the specifications for the
 8940 long measurement line in Section 8.1.3 of PS No. 2 (i.e., locate the points 16.7
 8941 percent, 50.0 percent, and 83.3 percent of the way across the stack). Alternatively,
 8942 the concentration measurements may be made at six traverse points along a
 8943 diameter. The six points must be located in accordance with Method 1 in
 8944 appendix A to 40 CFR 60, incorporated by reference in Section 225.140.

8945
 8946 b) Use Method 3A in appendix A to 40 CFR 60, incorporated by reference in
 8947 Section 225.140, to make the measurements. Data from the reference method
 8948 analyzers must be quality assured by performing analyzer calibration error and
 8949 system bias checks before the series of measurements and by conducting system
 8950 bias and calibration drift checks after the measurements, in accordance with the
 8951 procedures of Method 3A.

8952
 8953 c) Measure for a minimum of 2 minutes at each traverse point. To the extent

8954 practicable, complete the traverse within a 1-hour period.

8955

8956 d) If the load has remained constant (± 3.0 percent) during the traverse and if the

8957 reference method analyzers have passed all of the required quality assurance

8958 checks, proceed with the data analysis.

8959

8960 e) Calculate the average CO₂ (or O₂) concentrations at each of the individual

8961 traverse points. Then, calculate the arithmetic average CO₂ (or O₂) concentrations

8962 for all traverse points.

8963

8964 6.5.5.3 Stratification Test Results and Acceptance Criteria

8965

8966 a) For each diluent gas, the short reference method measurement line described in

8967 Section 8.1.3 of PS No. 2 may be used in lieu of the long measurement line

8968 prescribed in Section 8.1.3 of PS No. 2 if the results of a stratification test,

8969 conducted in accordance with Section 6.5.5.1 or 6.5.5.2 of this Exhibit (as

8970 appropriate; see Section 6.5.5(b)(3) of this Exhibit), show that the concentration at

8971 each individual traverse point differs by no more than ± 10.0 percent from the

8972 arithmetic average concentration for all traverse points. The results are also

8973 acceptable if the concentration at each individual traverse point differs by no more

8974 than ± 5 ppm or ± 0.5 percent CO₂ (or O₂) from the arithmetic average

8975 concentration for all traverse points.

8976

8977 b) For each diluent gas, a single reference method measurement point, located at

8978 least 1.0 meter from the stack wall and situated along one of the measurement

8979 lines used for the stratification test, may be used for that diluent gas if the results

8980 of a stratification test, conducted in accordance with Section 6.5.5.1 of this

8981 Exhibit, show that the concentration at each individual traverse point differs by no

8982 more than ± 5.0 percent from the arithmetic average concentration for all traverse

8983 points. The results are also acceptable if the concentration at each individual

8984 traverse point differs by no more than ± 3 ppm or ± 0.3 percent CO₂ (or O₂) from

8985 the arithmetic average concentration for all traverse points.

8986

8987 c) The owner or operator must keep the results of all stratification tests on-site, in a

8988 format suitable for inspection, as part of the supplementary RATA records

8989 required under Section 1.13(a)(7) of this Appendix.

8990

8991 6.5.6 Sampling Strategy

8992

8993 a) Conduct the reference method tests so they will yield results representative of the

8994 pollutant concentration, emission rate, moisture, temperature, and flue gas flow

8995 rate from the unit and can be correlated with the pollutant concentration monitor,

8996 CO₂ or O₂ monitor, flow monitor, and mercury CEMS measurements. The

8997 minimum acceptable time for a gas monitoring system RATA run or for a
 8998 moisture monitoring system RATA run is 21 minutes. For each run of a gas
 8999 monitoring system RATA, all necessary pollutant concentration measurements,
 9000 diluent concentration measurements, and moisture measurements (if applicable)
 9001 must, to the extent practicable, be made within a 60-minute period. For flow
 9002 monitor RATAs, the minimum time per run must be 5 minutes. Flow rate
 9003 reference method measurements may be made either sequentially from port to
 9004 port or simultaneously at two or more sample ports. The velocity measurement
 9005 probe may be moved from traverse point to traverse point either manually or
 9006 automatically. If, during a flow RATA, significant pulsations in the reference
 9007 method readings are observed, be sure to allow enough measurement time at each
 9008 traverse point to obtain an accurate average reading when a manual readout
 9009 method is used (e.g., a "sight-weighted" average from a manometer). Also, allow
 9010 sufficient measurement time to ensure that stable temperature readings are
 9011 obtained at each traverse point, particularly at the first measurement point at each
 9012 sample port, when a probe is moved sequentially from port-to-port. A minimum
 9013 of one set of auxiliary measurements for stack gas molecular weight
 9014 determination (i.e., diluent gas data and moisture data) is required for every clock
 9015 hour of a flow RATA or for every three test runs (whichever is less restrictive).
 9016 Alternatively, moisture measurements for molecular weight determination may be
 9017 performed before and after a series of flow RATA runs at a particular load level
 9018 (low, mid, or high), provided that the time interval between the two moisture
 9019 measurements does not exceed three hours. If this option is selected, the results of
 9020 the two moisture determinations must be averaged arithmetically and applied to
 9021 all RATA runs in the series. Successive flow RATA runs may be performed
 9022 without waiting in-between runs. If an O₂-diluent monitor is used as a CO₂
 9023 continuous emission monitoring system, perform a CO₂ system RATA (i.e.,
 9024 measure CO₂, rather than O₂, with the reference method). For moisture
 9025 monitoring systems, an appropriate coefficient, "K" factor or other suitable
 9026 mathematical algorithm may be developed prior to the RATA, to adjust the
 9027 monitoring system readings with respect to the reference method. If such a
 9028 coefficient, K-factor or algorithm is developed, it must be applied to the CEMS
 9029 readings during the RATA and (if the RATA is passed), to the subsequent CEMS
 9030 data, by means of the automated data acquisition and handling system. The owner
 9031 or operator must keep records of the current coefficient, K factor or algorithm, as
 9032 specified in Section 1.13(a)(5)(F) of this Appendix. Whenever the coefficient, K
 9033 factor or algorithm is changed, a RATA of the moisture monitoring system is
 9034 required. For the RATA of a mercury CEMS using the Ontario Hydro Method, or
 9035 for the RATA of a sorbent trap system (irrespective of the reference method
 9036 used), the time per run must be long enough to collect a sufficient mass of
 9037 mercury to analyze. For the RATA of a sorbent trap monitoring system, the type
 9038 of sorbent material used by the traps must be the same as for daily operation of
 9039 the monitoring system; however, the size of the traps used for the RATA may be

9040 smaller than the traps used for daily operation of the system. Spike the third
 9041 section of each sorbent trap with elemental mercury, as described in Section 7.1.2
 9042 of Exhibit D to this Appendix. Install a new pair of sorbent traps prior to each test
 9043 run. For each run, the sorbent trap data must be validated according to the quality
 9044 assurance criteria in Section 8 of Exhibit D to this Appendix.

- 9045
- 9046 b) To properly correlate individual mercury CEMS data (in lb/mmBtu) and
 9047 volumetric flow rate data with the reference method data, annotate the beginning
 9048 and end of each reference method test run (including the exact time of day) on the
 9049 individual chart recorders or other permanent recording devices.

9050

9051 6.5.7 Correlation of Reference Method and Continuous Emission Monitoring System
 9052

9053 Confirm that the monitor or monitoring system and reference method test results are on
 9054 consistent moisture, pressure, temperature, and diluent concentration basis (e.g., since the flow
 9055 monitor measures flow rate on a wet basis, Method 2 test results must also be on a wet basis).
 9056 Compare flow-monitor and reference method results on a scfh basis. Also, consider the response
 9057 times of the pollutant concentration monitor, the continuous emission monitoring system, and the
 9058 flow monitoring system to ensure comparison of simultaneous measurements.

9059

9060 For each relative accuracy test audit run, compare the measurements obtained from the monitor
 9061 or continuous emission monitoring system (in ppm, percent CO₂, lb/mmBtu, or other units)
 9062 against the corresponding reference method values. Tabulate the paired data in a table such as the
 9063 one shown in Figure 2.

9064

9065 6.5.8 Number of Reference Method Tests
 9066

9067 Perform a minimum of nine sets of paired monitor (or monitoring system) and reference method
 9068 test data for every required (i.e., certification, recertification, diagnostic, semiannual, or annual)
 9069 relative accuracy test audit. For 2-level and 3-level relative accuracy test audits of flow monitors,
 9070 perform a minimum of nine sets at each of the operating levels.

9071

9072 6.5.9 Reference Methods
 9073

9074 The following methods are from appendix A to 40 CFR 60, incorporated by reference in Section
 9075 225.140, or have been published by ASTM, and are the reference methods for performing
 9076 relative accuracy test audits under this part: Method 1 or 1A in appendix A-1 to 40 CFR 60 for
 9077 siting; Method 2 in appendices A-1 and A-2 to 40 CFR 60 or its allowable alternatives in
 9078 appendix A to 40 CFR 60 (except for Methods 2B and 2E in appendix A-1 to 40 CFR 60) for
 9079 stack gas velocity and volumetric flow rate; Methods 3, 3A or 3B in appendix A-2 to 40 CFR 60
 9080 for O₂ and CO₂; Method 4 in appendix A-3 to 40 CFR 60 for moisture; and for mercury, either
 9081 ASTM D6784-02 (the Ontario Hydro Method) (incorporated by reference under Section
 9082 225.140), Method 29 in appendix A-8 to 40 CFR 60, Method 30A, or Method 30B.

9083
9084 7. Calculations

9085
9086 7.1 Linearity Check

9087
9088 Analyze the linearity data for pollutant concentration monitors as follows. Calculate the
9089 percentage error in linearity based upon the reference value at the low-level, mid-level, and high-
9090 level concentrations specified in Section 6.2 of this Exhibit. Perform this calculation once during
9091 the certification test. Use the following equation to calculate the error in linearity for each
9092 reference value.
9093

9094
$$LE = \frac{|R - A|}{R} \times 100 \quad \text{(Equation A-4)}$$

9095
9096 Where:
9097

- 9098 LE = Percentage linearity error, based upon the reference value.
- 9099 R = Reference value of low-, mid-, or high-level calibration gas introduced into
9100 the monitoring system.
- 9101 A = Average of the monitoring system responses.

9102
9103 7.2 Calibration Error

9104 7.2.1 Pollutant Concentration and Diluent Monitors

9105
9106 For each reference value, calculate the percentage calibration error based upon instrument span
9107 for daily calibration error tests using the following equation:

9108
$$CE = \frac{|R - A|}{S} \times 100 \quad \text{(Equation A-5)}$$

9109 Where:

- 9110 CE = Calibration error as a percentage of the span of the instrument.
- 9111 R = Reference value of zero or upscale (high-level or mid-level, as applicable)
9112 calibration gas introduced into the monitoring system.
- 9113 A = Actual monitoring system response to the calibration gas.
- 9114 S = Span of the instrument, as specified in Section 2 of this Exhibit.

9115 7.2.2 Flow Monitor Calibration Error

9113 For each reference value, calculate the percentage calibration error based upon span using the
 9114 following equation:
 9115

$$CE = \frac{|R - A|}{S} \times 100 \quad \text{(Equation A-6)}$$

9117
 9118 Where:
 9119

- CE = Calibration error as a percentage of span.
- R = Low or high level reference value specified in Section 2.2.2.1 of this Exhibit.
- A = Actual flow monitor response to the reference value.
- S = Flow monitor calibration span value as determined under Section 2.1.2.2 of this Exhibit.

9120
 9121 7.3 Relative Accuracy for O₂ Monitors, Mercury Monitoring Systems, and Flow Monitors
 9122

9123 Analyze the relative accuracy test audit data from the reference method tests for CO₂ or O₂
 9124 monitors used only for heat input rate determination, mercury monitoring systems used to
 9125 determine mercury mass emissions under Sections 1.14 through 1.18 of Appendix B, and flow
 9126 monitors using the following procedures. Summarize the results on a data sheet. An example is
 9127 shown in Figure 2. Calculate the mean of the monitor or monitoring system measurement values.
 9128 Calculate the mean of the reference method values. Using data from the automated data
 9129 acquisition and handling system, calculate the arithmetic differences between the reference
 9130 method and monitor measurement data sets. Then calculate the arithmetic mean of the
 9131 difference, the standard deviation, the confidence coefficient, and the monitor or monitoring
 9132 system relative accuracy using the following procedures and equations.

9133
 9134 7.3.1 Arithmetic Mean
 9135

9136 Calculate the arithmetic mean of the differences, d, of a data set as follows.
 9137

$$d = \sum_{i=1}^n d_i \quad \text{(Equation A-7)}$$

9139
 9140 Where:
 9141

- n = Number of data points.
- d_i = The difference between a reference method value and the corresponding continuous emission monitoring system value (RM_i- CEM_i) at a given point in time i.

9142

9143
9144
9145
9146

7.3.2 Standard Deviation

Calculate the standard deviation, S_d , of a data set as follows:

$$S_d = \sqrt{\frac{\sum_{i=1}^n d_i^2 - \frac{\left(\sum_{i=1}^n d_i\right)^2}{n}}{n-1}} \quad \text{(Equation A-8)}$$

9147
9148
9149
9150

Where:

- n \equiv Number of data points.
- d_i \equiv The difference between a reference method value and the corresponding continuous emission monitoring system value ($RM_i - CEM_i$) at a given point in time i .

9151
9152
9153
9154
9155

7.3.3 Confidence Coefficient

Calculate the confidence coefficient (one-tailed), cc , of a data set as follows:

$$cc = t_{0.025} \frac{S_d}{\sqrt{n}} \quad \text{(Equation A-9)}$$

9156
9157
9158
9159

Where:

- $t_{0.025}$ \equiv t value (see Table 7-1).

9160

Table 7-1 t-Values

<u>n-1</u>	<u>t0.025</u>	<u>n-1</u>	<u>t0.025</u>	<u>n-1</u>	<u>t0.025</u>
<u>1</u>	<u>12.706</u>	<u>12</u>	<u>2.179</u>	<u>23</u>	<u>2.069</u>
<u>2</u>	<u>4.303</u>	<u>13</u>	<u>2.160</u>	<u>24</u>	<u>2.064</u>
<u>3</u>	<u>3.182</u>	<u>14</u>	<u>2.145</u>	<u>25</u>	<u>2.060</u>
<u>4</u>	<u>2.776</u>	<u>15</u>	<u>2.131</u>	<u>26</u>	<u>2.056</u>
<u>5</u>	<u>2.571</u>	<u>16</u>	<u>2.120</u>	<u>27</u>	<u>2.052</u>
<u>6</u>	<u>2.447</u>	<u>17</u>	<u>2.110</u>	<u>28</u>	<u>2.048</u>
<u>7</u>	<u>2.365</u>	<u>18</u>	<u>2.101</u>	<u>29</u>	<u>2.045</u>
<u>8</u>	<u>2.306</u>	<u>19</u>	<u>2.093</u>	<u>30</u>	<u>2.042</u>

<u>9</u>	<u>2.262</u>	<u>20</u>	<u>2.086</u>	<u>40</u>	<u>2.021</u>
<u>10</u>	<u>2.228</u>	<u>21</u>	<u>2.080</u>	<u>60</u>	<u>2.000</u>
<u>11</u>	<u>2.201</u>	<u>22</u>	<u>2.074</u>	<u>>60</u>	<u>1.960</u>

7.3.4 Relative Accuracy

Calculate the relative accuracy of a data set using the following equation.

$$RA = \frac{|\bar{d}| + |cc|}{\overline{RM}} \times 100 \quad \text{(Equation A-10)}$$

Where:

\overline{RM} = Arithmetic mean of the reference method values.

$|\bar{d}|$ = The absolute value of the mean difference between the reference method values and the corresponding continuous emission monitoring system values.

$|cc|$ = The absolute value of the confidence coefficient.

7.4 Bias Test

Test the following relative accuracy test audit data sets for bias: flow monitors, mercury concentration monitoring systems, and sorbent trap monitoring systems, using the procedures outlined in Sections 7.4.1 through 7.4.4 of this Exhibit. For multiple-load flow RATAs, perform a bias test at each load level designated as normal under Section 6.5.2.1 of this Exhibit.

7.4.1 Arithmetic Mean

Calculate the arithmetic mean of the difference, "d", of the data set using Equation A-7 of this Exhibit. To calculate bias for a flow monitor, "d" is, for each paired data point, the difference between the flow rate values (in scfh) obtained from the reference method and the monitor. To calculate bias for a mercury monitoring system when using the Ontario Hydro Method or Method 29 in appendix A-8 to 40 CFR 60, incorporated by reference in Section 225.140, "d" is, for each data point, the difference between the average mercury concentration value (in $\mu\text{g}/\text{m}^3$) from the paired Ontario Hydro or Method 29 in appendix A-8 to 40 CFR 60 sampling trains and the concentration measured by the monitoring system. For sorbent trap monitoring systems, use the average mercury concentration measured by the paired traps in the calculation of "d".

7.4.2 Standard Deviation

9192 Calculate the standard deviation, S_d , of the data set using Equation A-8.

9193

9194 7.4.3 Confidence Coefficient

9195

9196 Calculate the confidence coefficient, cc , of the data set using Equation A-9.

9197

9198 7.4.4 Bias Test

9199

9200 If, for the relative accuracy test audit data set being tested, the mean difference, d , is less than or
 9201 equal to the absolute value of the confidence coefficient, $|cc|$, the monitor or monitoring system

9202 has passed the bias test. If the mean difference, d , is greater than the absolute value of the
 9203 confidence coefficient, $|cc|$, the monitor or monitoring system has failed to meet the bias test

9204 requirement.

9205

9206 7.5 Reference Flow-to-Load Ratio or Gross Heat Rate

9207

9208 a) Except as provided in Section 7.6 of this Exhibit, the owner or operator must
 9209 determine R_{ref} , the reference value of the ratio of flow rate to unit load, each time
 9210 that a passing flow RATA is performed at a load level designated as normal in
 9211 Section 6.5.2.1 of this Exhibit. The owner or operator must report the current
 9212 value of R_{ref} in the electronic quarterly report required under 40 CFR 75.64,
 9213 incorporated by reference in Section 225.140, and must also report the completion
 9214 date of the associated RATA. If two load levels have been designated as normal
 9215 under Section 6.5.2.1 of this Exhibit, the owner or operator must determine a
 9216 separate R_{ref} value for each of the normal load levels. The reference flow-to-load
 9217 ratio must be calculated as follows:

9218

9219
$$R_{ref} = \frac{Q_{ref}}{L_{avg}} \times 10^{-5} \quad \text{(Equation A-13)}$$

9220

9221 Where:

9222

R_{ref} ≡ Reference value of the flow-to-load ratio, from the most recent
normal-load flow RATA, scfh/megawatts, scfh/1000 lb/hr of steam,
or scfh/ (mmBtu/hr of steam output).

Q_{ref} ≡ Average stack gas volumetric flow rate measured by the reference
method during the normal-load RATA, scfh.

L_{avg} ≡ Average unit load during the normal-load flow RATA, megawatts,
1000 lb/hr of steam, or mmBtu/hr of thermal output.

9223

9224 b) In Equation A-13, for a common stack, determine L_{avg} by summing, for each

9225 RATA run, the operating loads of all units discharging through the common stack,
 9226 and then taking the arithmetic average of the summed loads. For a unit that
 9227 discharges its emissions through multiple stacks, either determine a single value
 9228 of Q_{ref} for the unit or a separate value of Q_{ref} for each stack. In the former case,
 9229 calculate Q_{ref} by summing, for each RATA run, the volumetric flow rates through
 9230 the individual stacks and then taking the arithmetic average of the summed RATA
 9231 run flow rates. In the latter case, calculate the value of Q_{ref} for each stack by
 9232 taking the arithmetic average, for all RATA runs, of the flow rates through the
 9233 stack. For a unit with a multiple stack discharge configuration consisting of a
 9234 main stack and a bypass stack (e.g., a unit with a wet SO_2 scrubber), determine
 9235 Q_{ref} separately for each stack at the time of the normal load flow RATA. Round
 9236 off the value of R_{ref} to two decimal places.

9237
 9238 c) In addition to determining R_{ref} or as an alternative to determine R_{ref} , a reference
 9239 value of the gross heat rate (GHR) may be determined. In order to use this option,
 9240 quality assured diluent gas (CO_2 or O_2) must be available for each hour of the
 9241 most recent normal-load flow RATA. The reference value of the GHR must be
 9242 determined as follows:

9243
 9244
$$(GHR)_{ref} = \frac{(HeatInput)_{avg}}{L_{avg}} \times 1000 \quad \text{(Equation A-13a)}$$

9245
 9246 Where:
 9247

$(GHR)_{ref} \equiv$ Reference value of the gross heat rate at the time of the
most recent normal-load flow RATA, Btu/kwh, Btu/lb
steam load, or Btu heat input/mmBtu steam output.

$(HeatInput)_{avg} \equiv$ Average hourly heat input during the normal-load flow
RATA, as determined using the applicable equation in
Exhibit C to this Appendix, mmBtu/hr. For multiple stack
configurations, if the reference GHR value is determined
separately for each stack, use the hourly heat input
measured at each stack. If the reference GHR is determined
at the unit level, sum the hourly heat inputs measured at the
individual stacks.

$L_{avg} \equiv$ Average unit load during the normal-load flow RATA,
megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal
output.

9248
 9249 d) In the calculation of $(HeatInput)_{avg}$, use Q_{ref} , the average volumetric flow rate
 9250 measured by the reference method during the RATA, and use the average diluent
 9251 gas concentration measured during the flow RATA (i.e., the arithmetic average of

[FNa] RM means "reference method data".

[FNb] M means "monitor data".

[FNc] Make sure the RM and M data are on a consistent basis, either wet or dry.

9272
9273

Figure 3. Relative Accuracy Determination (Flow Monitors)

<u>Run</u> <u>time</u>	<u>Date</u> <u>and</u> <u>time</u>	<u>Flow rate (Low)</u> <u>(scf/hr) [FNa]</u>			<u>Flow rate (Normal)</u> <u>(scf/hr) [FNa]</u>			<u>Flow rate (High)</u> <u>(scf/hr) [FNa]</u>				
		<u>RM</u>	<u>M</u>	<u>Diff</u>	<u>RM</u>	<u>M</u>	<u>Diff</u>	<u>RM</u>	<u>M</u>	<u>Diff</u>		
<u>1</u>												
<u>2</u>												
<u>3</u>												
<u>4</u>												
<u>5</u>												
<u>6</u>												
<u>7</u>												
<u>8</u>												
<u>9</u>												
<u>10</u>												
<u>11</u>												
<u>12</u>												

Arithmetic Mean Difference (Eq. A-7).

Confidence Coefficient (Eq. A-9).

Relative Accuracy (Eq. A-10).

[FNa] Make sure the RM and M data are on a consistent basis, either wet or dry.

9274
9275

Figure 4. Relative Accuracy Determination (NO_x/Diluent Combined System)

<u>Reference method data NO_x system (lb/mmBtu)</u>							
<u>Run No.</u>	<u>Date and time</u>	<u>NO_x ()</u>	<u>[FNa]</u>	<u>O₂/CO₂%</u>	<u>RM</u>	<u>M</u>	<u>Difference</u>
<u>1</u>							
<u>2</u>							
<u>3</u>							
<u>4</u>							
<u>5</u>							
<u>6</u>							
<u>7</u>							
<u>8</u>							
<u>9</u>							
<u>10</u>							
<u>11</u>							
<u>12</u>							

Arithmetic Mean Difference (Eq. A-7).
Confidence Coefficient (Eq. A-9).
Relative Accuracy (Eq. A-10).

[FNa] Specify units: ppm, lb/dscf, mg/dscm.

9276
9277

Figure 5. Cycle Time

Date of test _____

Component/system ID#: _____

Analyzer type _____

Serial Number _____

High level gas concentration: _____ ppm/% (circle one)

Zero level gas concentration: _____ ppm/% (circle one)

Analyzer span setting: _____ ppm/% (circle one)

Upscale:

Stable starting monitor value: _____ ppm/% (circle one)

Stable ending monitor reading: _____ ppm/% (circle one)

Elapsed time: _____ Seconds

Downscale:

Stable starting monitor value: _____ ppm/% (circle one)

Stable ending monitor reading: _____ ppm/% (circle one)

Elapsed time: _____ seconds

Component cycle time = _____ seconds

System cycle time = _____ seconds

- 9278
- 9279 A. To determine the upscale cycle time (Figure 6a), measure the flue gas emissions until
- 9280 the response stabilizes. Record the stabilized value (see Section 6.4 of this Exhibit for the
- 9281 stability criteria).
- 9282
- 9283 B. Inject a high-level calibration gas into the port leading to the calibration cell or thimble
- 9284 (Point B). Allow the analyzer to stabilize. Record the stabilized value.
- 9285
- 9286 C. Determine the step change. The step change is equal to the difference between the
- 9287 final stable calibration gas value (Point D) and the stabilized stack emissions value (Point
- 9288 A).
- 9289
- 9290 D. Take 95% of the step change value and add the result to the stabilized stack emissions
- 9291 value (Point A). Determine the time at which 95% of the step change occurred (Point C).
- 9292
- 9293 E. Calculate the upscale cycle time by subtracting the time at which the calibration gas
- 9294 was injected (Point B) from the time at which 95% of the step change occurred (Point C).
- 9295 In this example, upscale cycle time = (11-5) = 6 minutes.
- 9296
- 9297 F. To determine the downscale cycle time (Figure 6b) repeat the procedures above,
- 9298 except that a zero gas is injected when the flue gas emissions have stabilized, and 95% of
- 9299 the step change in concentration is subtracted from the stabilized stack emissions value.
- 9300
- 9301 G. Compare the upscale and downscale cycle time values. The longer of these two times

9302 is the cycle time for the analyzer.
9303

9304 **Exhibit B to Appendix B – Quality Assurance and Quality Control Procedures**

9305
9306 1. Quality Assurance/Quality Control Program

9307
9308 Develop and implement a quality assurance/quality control (QA/QC) program for the continuous
9309 emission monitoring systems and their components. At a minimum, include in each QA/QC
9310 program a written plan that describes in detail (or that refers to separate documents containing)
9311 complete, step-by-step procedures and operations for each of the following activities. Upon
9312 request from regulatory authorities, the source must make all procedures, maintenance records,
9313 and ancillary supporting documentation from the manufacturer (e.g., software coefficients and
9314 troubleshooting diagrams) available for review during an audit. Electronic storage of the
9315 information in the QA/QC plan is permissible, provided that the information can be made
9316 available in hardcopy upon request during an audit.

9317
9318 1.1 Requirements for All Monitoring Systems

9319
9320 1.1.1 Preventive Maintenance

9321
9322 Keep a written record of procedures needed to maintain the monitoring system in proper
9323 operating condition and a schedule for those procedures. This must, at a minimum, include
9324 procedures specified by the manufacturers of the equipment and, if applicable, additional or
9325 alternate procedures developed for the equipment.

9326
9327 1.1.2 Recordkeeping and Reporting

9328
9329 Keep a written record describing procedures that will be used to implement the recordkeeping
9330 and reporting requirements in subparts E and G of 40 CFR 75, incorporated by reference in
9331 Section 225.140, and Sections 1.10 through 1.13 of Appendix B, as applicable.

9332
9333 1.1.3 Maintenance Records

9334
9335 Keep a record of all testing, maintenance, or repair activities performed on any monitoring
9336 system or component in a location and format suitable for inspection. A maintenance log may be
9337 used for this purpose. The following records should be maintained: date, time, and description of
9338 any testing, adjustment, repair, replacement, or preventive maintenance action performed on any
9339 monitoring system and records of any corrective actions associated with a monitor's outage
9340 period. Additionally, any adjustment that recharacterizes a system's ability to record and report
9341 emissions data must be recorded (e.g., changing of flow monitor or moisture monitoring system
9342 polynomial coefficients, K factors or mathematical algorithms, changing of temperature and
9343 pressure coefficients and dilution ratio settings), and a written explanation of the procedures used
9344 to make the adjustments must be kept.

9345
9346 1.1.4

9347
9348 The requirements in Section 6.1.2 of Exhibit A to this Appendix must be met by any Air
9349 Emissions Testing Body (AETB) performing the semiannual/annual RATAs described in Section
9350 2.3 of this Exhibit and the mercury emission tests described in Sections 1.15(c) and 1.15(d)(4) of
9351 Appendix B.

9352
9353 1.2 Specific Requirements for Continuous Emissions Monitoring Systems

9354
9355 1.2.1 Calibration Error Test and Linearity Check Procedures

9356
9357 Keep a written record of the procedures used for daily calibration error tests and linearity checks
9358 (e.g., how gases are to be injected, adjustments of flow rates and pressure, introduction of
9359 reference values, length of time for injection of calibration gases, steps for obtaining calibration
9360 error or error in linearity, determination of interferences, and when calibration adjustments
9361 should be made). Identify any calibration error test and linearity check procedures specific to the
9362 continuous emission monitoring system that vary from the procedures in Exhibit A to this
9363 Appendix.

9364
9365 1.2.2 Calibration and Linearity Adjustments

9366
9367 Explain how each component of the continuous emission monitoring system will be adjusted to
9368 provide correct responses to calibration gases, reference values, and/or indications of
9369 interference both initially and after repairs or corrective action. Identify equations, conversion
9370 factors and other factors affecting calibration of each continuous emission monitoring system.

9371
9372 1.2.3 Relative Accuracy Test Audit Procedures

9373
9374 Keep a written record of procedures and details peculiar to the installed continuous emission
9375 monitoring systems that are to be used for relative accuracy test audits, such as sampling and
9376 analysis methods.

9377
9378 1.2.4 Parametric Monitoring for Units With Add-on Emission Controls

9379
9380 The owner or operator shall keep a written (or electronic) record including a list of operating
9381 parameters for the add-on mercury emission controls, as applicable, and the range of each
9382 operating parameter that indicates the add-on emission controls are operating properly. The
9383 owner or operator shall keep a written (or electronic) record of the parametric monitoring data
9384 during each mercury missing data period.

9385
9386 1.3 Requirements for Sorbent Trap Monitoring Systems

9387
9388 1.3.1 Sorbent Trap Identification and Tracking

9389

9390 Include procedures for inscribing or otherwise permanently marking a unique identification
 9391 number on each sorbent trap for tracking purposes. Keep records of the ID of the monitoring
 9392 system in which each sorbent trap is used and the dates and hours of each mercury collection
 9393 period.

9394
 9395 1.3.2 Monitoring System Integrity and Data Quality
 9396

9397 Explain the procedures used to perform the leak checks when sorbent traps are placed in service
 9398 and removed from service. Also explain the other QA procedures used to ensure system integrity
 9399 and data quality, including, but not limited to, gas flow meter calibrations, verification of
 9400 moisture removal, and ensuring air-tight pump operation. In addition, the QA plan must include
 9401 the data acceptance and quality control criteria in Section 8 of Exhibit D to this Appendix. All
 9402 reference meters used to calibrate the gas flow meters (e.g., wet test meters) must be periodically
 9403 recalibrated. Annual, or more frequent, recalibration is recommended. If a NIST-traceable
 9404 calibration device is used as a reference flow meter, the QA plan must include a protocol for
 9405 ongoing maintenance and periodic recalibration to maintain the accuracy and NIST-traceability
 9406 of the calibrator.

9407
 9408 1.3.3 Mercury Analysis
 9409

9410 Explain the chain of custody employed in packing, transporting, and analyzing the sorbent traps
 9411 (see Sections 7.2.8 and 7.2.9 in Exhibit D to this Appendix.). Keep records of all mercury
 9412 analyses. The analyses must be performed in accordance with the procedures described in
 9413 Section 10 of Exhibit D to this Appendix.

9414
 9415 1.3.4 Laboratory Certification
 9416

9417 The QA Plan must include documentation that the laboratory performing the analyses on the
 9418 carbon sorbent traps is certified by the International Organization for Standardization (ISO) to
 9419 have a proficiency that meets the requirements of ISO 17025. Alternatively, if the laboratory
 9420 performs the spike recovery study described in Section 10.3 of Exhibit D to this Appendix and
 9421 repeats that procedure annually, ISO certification is not required.

9422
 9423 1.3.5 Data Collection Period
 9424

9425 State, and provide the rationale for, the minimum acceptable data collection period (e.g., one
 9426 day, one week, etc.) for the size of the sorbent trap selected for the monitoring. Include in the
 9427 discussion such factors as the mercury concentration in the stack gas, the capacity of the sorbent
 9428 trap, and the minimum mass of mercury required for the analysis.

9429
 9430 1.3.6 Relative Accuracy Test Audit Procedures
 9431

9432 Keep records of the procedures and details peculiar to the sorbent trap monitoring systems that

9433 are to be followed for relative accuracy test audits, such as sampling and analysis methods.

9434
9435 2. Frequency of Testing

9436
9437 A summary chart showing each quality assurance test and the frequency at which each test is
9438 required is located at the end of this Exhibit in Figure 1.

9439
9440 2.1 Daily Assessments

9441
9442 Perform the following daily assessments to quality-assure the hourly data recorded by the
9443 monitoring systems during each period of unit operation, or, for a bypass stack or duct, each
9444 period in which emissions pass through the bypass stack or duct. These requirements are
9445 effective as of the date when the monitor or continuous emission monitoring system completes
9446 certification testing.

9447
9448 2.1.1 Calibration Error Test

9449
9450 Except as provided in Section 2.1.1.2 of this Exhibit, perform the daily calibration error test of
9451 each gas monitoring system (including moisture monitoring systems consisting of wet- and dry-
9452 basis O₂ analyzers) according to the procedures in Section 6.3.1 of Exhibit A to this Appendix,
9453 and perform the daily calibration error test of each flow monitoring system according to the
9454 procedure in Section 6.3.2 of Exhibit A to this Appendix. When two measurement ranges (low
9455 and high) are required for a particular parameter, perform sufficient calibration error tests on
9456 each range to validate the data recorded on that range, according to the criteria in Section 2.1.5 of
9457 this Exhibit.

9458
9459 For units with add-on emission controls and dual-span or auto-ranging monitors, and other units
9460 that use the maximum expected concentration to determine calibration gas values, perform the
9461 daily calibration error tests on each scale that has been used since the previous calibration error
9462 test. For example, if the pollutant concentration has not exceeded the low-scale value (based on
9463 the maximum expected concentration) since the previous calibration error test, the calibration
9464 error test may be performed on the low-scale only. If, however, the concentration has exceeded
9465 the low-scale span value for one hour or longer since the previous calibration error test, perform
9466 the calibration error test on both the low- and high-scales.

9467
9468 2.1.1.1 On-line Daily Calibration Error Tests

9469
9470 Except as provided in Section 2.1.1.2 of this Exhibit, all daily calibration error tests must be
9471 performed while the unit is in operation at normal, stable conditions (i.e., "on-line").

9472
9473 2.1.1.2 Off-line Daily Calibration Error Tests

9474

9475 Daily calibrations may be performed while the unit is not operating (i.e., "off-line") and may be
 9476 used to validate data for a monitoring system that meets the following conditions:

- 9477
- 9478 1) An initial demonstration test of the monitoring system is successfully completed
 9479 and the results are reported in the quarterly report required under 40 CFR 75.64,
 9480 incorporated by reference in Section 225.140. The initial demonstration test,
 9481 hereafter called the "off-line calibration demonstration", consists of an off-line
 9482 calibration error test followed by an on-line calibration error test. Both the off-line
 9483 and on-line portions of the off-line calibration demonstration must meet the
 9484 calibration error performance specification in Section 3.1 of Exhibit A to
 9485 Appendix B. Upon completion of the off-line portion of the demonstration, the
 9486 zero and upscale monitor responses may be adjusted, but only toward the true
 9487 values of the calibration gases or reference signals used to perform the test and
 9488 only in accordance with the routine calibration adjustment procedures specified in
 9489 the quality control program required under Section 1 of this Exhibit. Once these
 9490 adjustments are made, no further adjustments may be made to the monitoring
 9491 system until after completion of the on-line portion of the off-line calibration
 9492 demonstration. Within 26 clock hours after the completion hour of the off-line
 9493 portion of the demonstration, the monitoring system must successfully complete
 9494 the first attempted calibration error test, i.e., the on-line portion of the
 9495 demonstration.
- 9496
- 9497 2) For each monitoring system that has passed the off-line calibration demonstration,
 9498 off-line calibration error tests may be used on a limited basis to validate data, in
 9499 accordance with subsection (2) in Section 2.1.5.1 of this Exhibit.

9500

9501 2.1.2 Daily Flow Interference Check

9502

9503 Perform the daily flow monitor interference checks specified in Section 2.2.2.2 of Exhibit A to
 9504 this Appendix while the unit is in operation at normal, stable conditions.

9505

9506 2.1.3 Additional Calibration Error Tests and Calibration Adjustments

9507

- 9508 a) In addition to the daily calibration error tests required under Section 2.1.1 of this
 9509 Exhibit, a calibration error test of a monitor must be performed in accordance
 9510 with Section 2.1.1 of this Exhibit, as follows: whenever a daily calibration error
 9511 test is failed; whenever a monitoring system is returned to service following repair
 9512 or corrective maintenance that could affect the monitor's ability to accurately
 9513 measure and record emissions data; or after making certain calibration
 9514 adjustments, as described in this Section. Except in the case of the routine
 9515 calibration adjustments described in this Section, data from the monitor are
 9516 considered invalid until the required additional calibration error test has been
 9517 successfully completed.

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- b) Routine calibration adjustments of a monitor are permitted after any successful calibration error test. These routine adjustments must be made so as to bring the monitor readings as close as practicable to the known tag values of the calibration gases or to the actual value of the flow monitor reference signals. An additional calibration error test is required following routine calibration adjustments where the monitor's calibration has been physically adjusted (e.g., by turning a potentiometer) to verify that the adjustments have been made properly. An additional calibration error test is not required, however, if the routine calibration adjustments are made by means of a mathematical algorithm programmed into the data acquisition and handling system. It is recommended that routine calibration adjustments be made, at a minimum, whenever the daily calibration error exceeds the limits of the applicable performance specification in Exhibit A to this Appendix for the pollutant concentration monitor, CO₂ or O₂ monitor, or flow monitor.

- c) Additional (non-routine) calibration adjustments of a monitor are permitted prior to (but not during) linearity checks and RATAs and at other times, provided that an appropriate technical justification is included in the quality control program required under Section 1 of this Exhibit. The allowable non-routine adjustments are as follows. The owner or operator may physically adjust the calibration of a monitor (e.g., by means of a potentiometer), provided that the post-adjustment zero and upscale responses of the monitor are within the performance specifications of the instrument given in Section 3.1 of Exhibit A to this Appendix. An additional calibration error test is required following such adjustments to verify that the monitor is operating within the performance specifications at both the zero and upscale calibration levels.

2.1.4 Data Validation

- a) An out-of-control period occurs when the calibration error of a CO₂ or O₂ monitor (including O₂ monitors used to measure CO₂ emissions or percent moisture) exceeds 1.0 percent CO₂ or O₂, or when the calibration error of a flow monitor or a moisture sensor exceeds 6.0 percent of the span value, which is twice the applicable specification of Exhibit A to this Appendix. Notwithstanding, a differential pressure-type flow monitor for which the calibration error exceeds 6.0 percent of the span value will not be considered out-of-control if $|R - A|$, the absolute value of the difference between the monitor response and the reference value in Equation A-6 of Exhibit A to this Appendix, is < 0.02 inches of water. For a mercury monitor, an out-of-control period occurs when the calibration error exceeds 5.0% of the span value. Notwithstanding, the mercury monitor will not be considered out-of-control if $|R - A|$ in Equation A-6 does not exceed 1.0 $\mu\text{g}/\text{scm}$.

The out-of-control period begins upon failure of the calibration error test and ends upon completion of a successful calibration error test. Note, that if a failed calibration, corrective action, and successful calibration error test occur within the same hour, emission data for that hour recorded by the monitor after the successful calibration error test may be used for reporting purposes, provided that two or more valid readings are obtained as required by Section 1.2 of this Appendix. Emission data must not be reported from an out-of-control monitor.

- b) An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of completion of the failed interference check and ends with the hour of completion of an interference check that is passed.

2.1.5 Quality Assurance of Data With Respect to Daily Assessments

When a monitoring system passes a daily assessment (i.e., daily calibration error test or daily flow interference check), data from that monitoring system are prospectively validated for 26 clock hours (i.e., 24 hours plus a 2-hour grace period) beginning with the hour in which the test is passed, unless another assessment (i.e., a daily calibration error test, an interference check of a flow monitor, a quarterly linearity check, a quarterly leak check, or a relative accuracy test audit) is failed within the 26-hour period.

2.1.5.1 Data Invalidation with Respect to Daily Assessments

The following specific rules apply to the invalidation of data with respect to daily assessments:

- 1) Data from a monitoring system are invalid, beginning with the first hour following the expiration of a 26-hour data validation period or beginning with the first hour following the expiration of an 8-hour start-up grace period (as provided under Section 2.1.5.2 of this Exhibit), if the required subsequent daily assessment has not been conducted.
- 2) For a monitor that has passed the off-line calibration demonstration, a combination of on-line and off-line calibration error tests may be used to validate data from the monitor, as follows. For a particular unit (or stack) operating hour, data from a monitor may be validated using a successful off-line calibration error test if:
 - a) An on-line calibration error test has been passed within the previous 26 unit (or stack) operating hours; and
 - b) the 26 clock hour data validation window for the off-line calibration error test has not expired. If either of these conditions is

9603 not met, then the data from the monitor are invalid with respect to
 9604 the daily calibration error test requirement. Data from the monitor
 9605 must remain invalid until the appropriate on-line or off-line
 9606 calibration error test is successfully completed so that both
 9607 conditions in subsections (a) and (b) are met.

- 9608
- 9609 3) For units with two measurement ranges (low and high) for a particular
 9610 parameter, when separate analyzers are used for the low and high ranges, a
 9611 failed or expired calibration on one of the ranges does not affect the
 9612 quality-assured data status on the other range. For a dual-range analyzer
 9613 (i.e., a single analyzer with two measurement scales), a failed calibration
 9614 error test on either the low or high scale results in an out-of-control period
 9615 for the monitor. Data from the monitor remain invalid until corrective
 9616 actions are taken and "hands-off" calibration error tests have been passed
 9617 on both ranges. However, if the most recent calibration error test on the
 9618 high scale was passed but has expired, while the low scale is up-to-date on
 9619 its calibration error test requirements (or vice-versa), the expired
 9620 calibration error test does not affect the quality-assured status of the data
 9621 recorded on the other scale.

9622

9623 2.1.5.2 Daily Assessment Start-Up Grace Period

9624

9625 For the purpose of quality assuring data with respect to a daily assessment (i.e., a daily
 9626 calibration error test or a flow interference check), a start-up grace period may apply when a unit
 9627 begins to operate after a period of non-operation. The start-up grace period for a daily calibration
 9628 error test is independent of the start-up grace period for a daily flow interference check. To
 9629 qualify for a start-up grace period for a daily assessment, there are two requirements:

- 9630
- 9631 1) The unit must have resumed operation after being in outage for 1 or more
 9632 hours (i.e., the unit must be in a start-up condition) as evidenced by a
 9633 change in unit operating time from zero in one clock hour to an operating
 9634 time greater than zero in the next clock hour.
- 9635
- 9636 2) For the monitoring system to be used to validate data during the grace
 9637 period, the previous daily assessment of the same kind must have been
 9638 passed on-line within 26 clock hours prior to the last hour in which the
 9639 unit operated before the outage. In addition, the monitoring system must
 9640 be in-control with respect to quarterly and semi-annual or annual
 9641 assessments.

9642

9643 If both of the above conditions are met, then a start-up grace period of up to 8 clock hours
 9644 applies, beginning with the first hour of unit operation following the outage. During the start-up
 9645 grace period, data generated by the monitoring system are considered quality-assured. For each

9646 monitoring system, a start-up grace period for a calibration error test or flow interference check
 9647 ends when either: (1) a daily assessment of the same kind (i.e., calibration error test or flow
 9648 interference check) is performed; or (2) 8 clock hours have elapsed (starting with the first hour of
 9649 unit operation following the outage), whichever occurs first.

9650
 9651 2.1.6 Data Recording
 9652

9653 Record and tabulate all calibration error test data according to month, day, clock-hour, and
 9654 magnitude in either ppm, percent volume, or scfh. Program monitors that automatically adjust
 9655 data to the corrected calibration values (e.g., microprocessor control) to record either: (1) the
 9656 unadjusted concentration or flow rate measured in the calibration error test prior to resetting the
 9657 calibration, or (2) the magnitude of any adjustment. Record the following applicable flow
 9658 monitor interference check data: (1) sample line/sensing port pluggage, and (2) malfunction of
 9659 each RTD, transceiver, or equivalent.

9660
 9661 2.2 Quarterly Assessments
 9662

9663 For each primary and redundant backup monitor or monitoring system, perform the following
 9664 quarterly assessments. This requirement applies as of the calendar quarter following the calendar
 9665 quarter in which the monitor or continuous emission monitoring system is provisionally certified.

9666
 9667 2.2.1 Linearity Check
 9668

9669 Unless a particular monitor (or monitoring range) is exempted under this subsection or under
 9670 Section 6.2 of Exhibit A to this Appendix, perform a linearity check, in accordance with the
 9671 procedures in Section 6.2 of Exhibit A to this Appendix, for each primary and redundant backup,
 9672 mercury, pollutant concentration monitor and each primary and redundant backup CO₂ or O₂
 9673 monitor (including O₂ monitors used to measure CO₂ emissions or to continuously monitor
 9674 moisture) at least once during each QA operating quarter, as defined in 40 CFR 72.2,
 9675 incorporated by reference in Section 225.140. For mercury monitors, perform the linearity
 9676 checks using elemental mercury standards. Alternatively, you may perform 3-level system
 9677 integrity checks at the same three calibration gas levels (i.e., low, mid, and high), using a NIST-
 9678 traceable source of oxidized mercury. If you choose this option, the performance specification in
 9679 Section 3.2(c) of Exhibit A to this Part must be met at each gas level. For units using both a low
 9680 and high span value, a linearity check is required only on the ranges used to record and report
 9681 emission data during the QA operating quarter. Conduct the linearity checks no less than 30 days
 9682 apart, to the extent practicable. The data validation procedures in Section 2.2.3(e) of this Exhibit
 9683 must be followed.

9684
 9685 2.2.2 Leak Check
 9686

9687 For differential pressure flow monitors, perform a leak check of all sample lines (a manual check
 9688 is acceptable) at least once during each QA operating quarter. For this test, the unit does not have

9689 to be in operation. Conduct the leak checks no less than 30 days apart, to the extent practicable.
 9690 If a leak check is failed, follow the applicable data validation procedures in Section 2.2.3(g) of
 9691 this Exhibit.

9692
 9693 2.2.3 Data Validation
 9694

9695 a) A linearity check must not be commenced if the monitoring system is operating
 9696 out-of-control with respect to any of the daily or semiannual quality assurance
 9697 assessments required by Sections 2.1 and 2.3 of this Exhibit or with respect to the
 9698 additional calibration error test requirements in Section 2.1.3 of this Exhibit.

9700 b) Each required linearity check must be done according to subsection (b)(1), (b)(2)
 9701 or (b)(3) of this Section:

9702
 9703 1) The linearity check may be done "cold", i.e., with no corrective
 9704 maintenance, repair, calibration adjustments, re-linearization or
 9705 reprogramming of the monitor prior to the test.

9706
 9707 2) The linearity check may be done after performing only the routine or non-
 9708 routine calibration adjustments described in Section 2.1.3 of this Exhibit
 9709 at the various calibration gas levels (zero, low, mid or high), but no other
 9710 corrective maintenance, repair, re-linearization or reprogramming of the
 9711 monitor. Trial gas injection runs may be performed after the calibration
 9712 adjustments and additional adjustments within the allowable limits in
 9713 Section 2.1.3 of this Exhibit may be made prior to the linearity check, as
 9714 necessary, to optimize the performance of the monitor. The trial gas
 9715 injections need not be reported, provided that they meet the specification
 9716 for trial gas injections in Section 1.4(b)(3)(G)(v) of this Appendix.
 9717 However, if, for any trial injection, the specification in Section
 9718 1.4(b)(3)(G)(v) is not met, the trial injection must be counted as an aborted
 9719 linearity check.

9720
 9721 3) The linearity check may be done after repair, corrective maintenance or
 9722 reprogramming of the monitor. In this case, the monitor must be
 9723 considered out-of-control from the hour in which the repair, corrective
 9724 maintenance or reprogramming is commenced until the linearity check has
 9725 been passed. Alternatively, the data validation procedures and associated
 9726 timelines in Sections 1.4(b)(3)(B) through (I) of this Appendix may be
 9727 followed upon completion of the necessary repair, corrective maintenance,
 9728 or reprogramming. If the procedures in Section 1.4(b)(3) are used, the
 9729 words "quality assurance" apply instead of the word "recertification".

9730
 9731 c) Once a linearity check has been commenced, the test must be done hands-off.

- 9732 That is, no adjustments of the monitor are permitted during the linearity test
 9733 period, other than the routine calibration adjustments following daily calibration
 9734 error tests, as described in Section 2.1.3 of this Exhibit. If a routine daily
 9735 calibration error test is performed and passed just prior to a linearity test (or
 9736 during a linearity test period) and a mathematical correction factor is
 9737 automatically applied by the DAHS, the correction factor must be applied to all
 9738 subsequent data recorded by the monitor, including the linearity test data.
 9739
- 9740 d) If a daily calibration error test is failed during a linearity test period, prior to
 9741 completing the test, the linearity test must be repeated. Data from the monitor are
 9742 invalidated prospectively from the hour of the failed calibration error test until the
 9743 hour of completion of a subsequent successful calibration error test. The linearity
 9744 test must not be commenced until the monitor has successfully completed a
 9745 calibration error test.
 9746
- 9747 e) An out-of-control period occurs when a linearity test is failed (i.e., when the error
 9748 in linearity at any of the three concentrations in the quarterly linearity check (or
 9749 any of the six concentrations, when both ranges of a single analyzer with a dual
 9750 range are tested) exceeds the applicable specification in Section 3.2 of Exhibit A
 9751 to this Appendix) or when a linearity test is aborted due to a problem with the
 9752 monitor or monitoring system. The out-of-control period begins with the hour of
 9753 the failed or aborted linearity check and ends with the hour of completion of a
 9754 satisfactory linearity check following corrective action and/or monitor repair,
 9755 unless the option in subsection (b)(3) of this Section to use the data validation
 9756 procedures and associated timelines in Section 1.4(b)(3)(B) through (I) of this
 9757 Appendix has been selected, in which case the beginning and end of the out-of-
 9758 control period must be determined in accordance with Sections 1.4(b)(3)(G)(i)
 9759 and (ii). For a dual-range analyzer, "hands-off" linearity checks must be passed on
 9760 both measurement scales to end the out-of-control period.
 9761
- 9762 f) No more than four successive calendar quarters must elapse after the quarter in
 9763 which a linearity check of a monitor or monitoring system (or range of a monitor
 9764 or monitoring system) was last performed without a subsequent linearity test
 9765 having been conducted. If a linearity test has not been completed by the end of the
 9766 fourth calendar quarter since the last linearity test, then the linearity test must be
 9767 completed within a 168 unit operating hour or stack operating hour "grace period"
 9768 (as provided in Section 2.2.4 of this Exhibit) following the end of the fourth
 9769 successive elapsed calendar quarter, or data from the CEMS (or range) will
 9770 become invalid.
 9771
- 9772 g) An out-of-control period also occurs when a flow monitor sample line leak is
 9773 detected. The out-of-control period begins with the hour of the failed leak check
 9774 and ends with the hour of a satisfactory leak check following corrective action.

9775
 9776 h) For each monitoring system, report the results of all completed and partial
 9777 linearity tests that affect data validation (i.e., all completed, passed linearity
 9778 checks; all completed, failed linearity checks; and all linearity checks aborted due
 9779 to a problem with the monitor, including trial gas injections counted as failed test
 9780 attempts under subsection (b)(2) of this Section or under Section 1.4(b)(3)(G)(vi)
 9781 of Appendix B), in the quarterly report required under 40 CFR 75.64,
 9782 incorporated by reference in Section 225.140. Note that linearity attempts that are
 9783 aborted or invalidated due to problems with the reference calibration gases or due
 9784 to operational problems with the affected units need not be reported. Such partial
 9785 tests do not affect the validation status of emission data recorded by the monitor.
 9786 A record of all linearity tests, trial gas injections and test attempts (whether
 9787 reported or not) must be kept on-site as part of the official test log for each
 9788 monitoring system.
 9789

9790 2.2.4 Linearity and Leak Check Grace Period
 9791

9792 a) When a required linearity test or flow monitor leak check has not been completed
 9793 by the end of the QA operating quarter in which it is due or if, due to infrequent
 9794 operation of a unit or infrequent use of a required high range of a monitor or
 9795 monitoring system, four successive calendar quarters have elapsed after the
 9796 quarter in which a linearity check of a monitor or monitoring system (or range)
 9797 was last performed without a subsequent linearity test having been done, the
 9798 owner or operator has a grace period of 168 consecutive unit operating hours, as
 9799 defined in 40 CFR 72.2, incorporated by reference in Section 225.140 (or, for
 9800 monitors installed on common stacks or bypass stacks, 168 consecutive stack
 9801 operating hours, as defined in 40 CFR 72.2) in which to perform a linearity test or
 9802 leak check of that monitor or monitoring system (or range). The grace period
 9803 begins with the first unit or stack operating hour following the calendar quarter in
 9804 which the linearity test was due. Data validation during a linearity or leak check
 9805 grace period must be done in accordance with the applicable provisions in Section
 9806 2.2.3 of this Exhibit.
 9807

9808 b) If, at the end of the 168 unit (or stack) operating hour grace period, the required
 9809 linearity test or leak check has not been completed, data from the monitoring
 9810 system (or range) will be invalid, beginning with the first unit operating hour
 9811 following the expiration of the grace period. Data from the monitoring system (or
 9812 range) remain invalid until the hour of completion of a subsequent successful
 9813 hands-off linearity test or leak check of the monitor or monitoring system (or
 9814 range). Note that when a linearity test or a leak check is conducted within a grace
 9815 period for the purpose of satisfying the linearity test or leak check requirement
 9816 from a previous QA operating quarter, the results of that linearity test or leak
 9817 check may only be used to meet the linearity check or leak check requirement of

9818 the previous quarter, not the quarter in which the missed linearity test or leak
 9819 check is completed.

9820 2.2.5 Flow-to-Load Ratio or Gross Heat Rate Evaluation

- 9821
- 9822
- 9823 a) Applicability and methodology. Unless exempted from the flow-to-load ratio test
 9824 under Section 7.8 to Appendix A to 40 CFR 75 , the owner or operator must, for
 9825 each flow rate monitoring system installed on each unit, common stack or
 9826 multiple stack, evaluate the flow-to-load ratio quarterly, i.e., for each QA
 9827 operating quarter (as defined in 40 CFR 72.2, incorporated by reference in Section
 9828 225.140). At the end of each QA operating quarter, the owner or operator must
 9829 use Equation B-1 to calculate the flow-to-load ratio for every hour during the
 9830 quarter in which: the unit (or combination of units, for a common stack) operated
 9831 within ± 10.0 percent of L_{avg} , the average load during the most recent normal-load
 9832 flow RATA; and a quality assured hourly average flow rate was obtained with a
 9833 certified flow rate monitor. Alternatively, for the reasons stated in subsections
 9834 (c)(1) through (6) of this Section, the owner or operator may exclude from the
 9835 data analysis certain hours within ± 10.0 percent of L_{avg} and may calculate L_{avg}
 9836 values for only the remaining hours.

9837

$$R_h = \frac{Q_h}{L_h} \times 10^{-5} \quad \text{(Equation B-1)}$$

9838

9839 Where:

- 9840
- 9841
- R_h ≡ Hourly value of the flow-to-load ratio, scfh/megawatts, scfh/1000 lb/hr
of steam, or scfh/(mmBtu/hr thermal output).
- Q_h ≡ Hourly stack gas volumetric flow rate, as measured by the flow rate
monitor, scfh.
- L_h ≡ Hourly unit load, megawatts, 1000 lb/hr of steam, or mmBtu/hr
thermal output; must be within + 10.0 percent of L_{avg} during the most
recent normal-load flow RATA.

- 9842
- 9843 1) In Equation B-1, the owner or operator may use either bias-adjusted flow
 9844 rates or unadjusted flow rates, provided that all of the ratios are calculated
 9845 the same way. For a common stack, L_h will be the sum of the hourly
 9846 operating loads of all units that discharge through the stack. For a unit that
 9847 discharges its emissions through multiple stacks or that monitors its
 9848 emissions in multiple breechings, Q_h will be either the combined hourly
 9849 volumetric flow rate for all of the stacks or ducts (if the test is done on a
 9850 unit basis) or the hourly flow rate through each stack individually (if the
 9851 test is performed separately for each stack). For a unit with a multiple

9852 stack discharge configuration consisting of a main stack and a bypass
 9853 stack, each of which has a certified flow monitor (e.g., a unit with a wet
 9854 SO₂ scrubber), calculate the hourly flow-to-load ratios separately for each
 9855 stack. Round off each value of R_h to two decimal places.

- 9856
- 9857 2) Alternatively, the owner or operator may calculate the hourly gross heat
 9858 rates (GHR) in lieu of the hourly flow-to-load ratios. The hourly GHR
 9859 must be determined only for those hours in which quality assured flow rate
 9860 data and diluent gas (CO₂ or O₂) concentration data are both available
 9861 from a certified monitor or monitoring system or reference method. If this
 9862 option is selected, calculate each hourly GHR value as follows:
 9863

9864
$$(GHR)_h = \frac{(HeatInput)_h}{L_h} \times 1000 \quad \text{(Equation B-1a)}$$

9865

9866 Where:
 9867

(GHR)_h = Hourly value of the gross heat rate, Btu/kwh, Btu/lb steam
load, or 1000 mmBtu heat input/mmBtu thermal output.

(HeatInput)_h = Hourly heat input, as determined from the quality assured
flow rate and diluent data, using the applicable equation in
Exhibit C to this Appendix, mmBtu/hr.

L_h = Hourly unit load, megawatts, 1000 lb/hr of steam, or
mmBtu/hr thermal output; must be within + 10.0 percent of
L_{avg} during the most recent normal-load flow RATA.

- 9868
- 9869 3) In Equation B-1a, the owner or operator may either use bias-adjusted flow
 9870 rates or unadjusted flow rates in the calculation of (HeatInput)_h, provided
 9871 that all of the heat input values are determined in the same manner.
 9872

- 9873 4) The owner or operator must evaluate the calculated hourly flow-to-load
 9874 ratios (or gross heat rates) as follows. A separate data analysis must be
 9875 performed for each primary and each redundant backup flow rate monitor
 9876 used to record and report data during the quarter. Each analysis must be
 9877 based on a minimum of 168 acceptable recorded hourly average flow rates
 9878 (i.e., at loads within ± 10 percent of L_{avg}). When two RATA load levels
 9879 are designated as normal, the analysis must be performed at the higher
 9880 load level, unless there are fewer than 168 acceptable data points available
 9881 at that load level, in which case the analysis must be performed at the
 9882 lower load level. If, for a particular flow monitor, fewer than 168
 9883 acceptable hourly flow-to-load ratios (or GHR values) are available at any
 9884 of the load levels designated as normal, a flow-to-load (or GHR)

9885 evaluation is not required for that monitor for that calendar quarter.

9886
 9887 5) For each flow monitor, use Equation B-2 in this Exhibit to calculate E_h ,
 9888 the absolute percentage difference between each hourly R_h value and R_{ref} ,
 9889 the reference value of the flow-to-load ratio, as determined in accordance
 9890 with Section 7.7 to Appendix A to 40 CFR 75. Note that R_{ref} must always
 9891 be based upon the most recent normal-load RATA, even if that RATA was
 9892 performed in the calendar quarter being evaluated.

9893

9894
$$E_h = \frac{|R_{ref} - R_h|}{R_{ref}} \times 100 \quad \text{(Equation B-2)}$$

9895

9896 Where:

9897

E_h = Absolute percentage difference between the hourly average flow-to-load ratio and the reference value of the flow-to-load ratio at normal load.

R_h = The hourly average flow-to-load ratio, for each flow rate recorded at a load level within ± 10.0 percent of L_{avg} .

R_{ref} = The reference value of the flow-to-load ratio from the most recent normal-load flow RATA, determined in accordance with Section 7.7 to Appendix A to 40 CFR 75.

9898

9899 6) Equation B-2 must be used in a consistent manner. That is, use R_{ref} and R_h
 9900 if the flow-to-load ratio is being evaluated, and use (GHR)_{ref} and (GHR)_h
 9901 if the gross heat rate is being evaluated. Finally, calculate E_f , the
 9902 arithmetic average of all of the hourly E_h values. The owner or operator
 9903 must report the results of each quarterly flow-to-load (or gross heat rate)
 9904 evaluation, as determined from Equation B-2, in the electronic quarterly
 9905 report required under 40 CFR 75.64.

9906

9907 b) Acceptable results. The results of a quarterly flow-to-load (or gross heat rate)
 9908 evaluation are acceptable, and no further action is required, if the calculated value
 9909 of E_f is less than or equal to: (1) 15.0 percent, if L_{avg} for the most recent normal-
 9910 load flow RATA is ≥ 60 megawatts (or ≥ 500 klb/hr of steam) and if unadjusted
 9911 flow rates were used in the calculations; or (2) 10.0 percent, if L_{avg} for the most
 9912 recent normal-load flow RATA is ≥ 60 megawatts (or ≥ 500 klb/hr of steam) and
 9913 if bias-adjusted flow rates were used in the calculations; or (3) 20.0 percent, if
 9914 L_{avg} for the most recent normal-load flow RATA is < 60 megawatts (or < 500
 9915 klb/hr of steam) and if unadjusted flow rates were used in the calculations; or (4)
 9916 15.0 percent, if L_{avg} for the most recent normal-load flow RATA is < 60
 9917 megawatts (or < 500 klb/hr of steam) and if bias-adjusted flow rates were used in

9918 the calculations. If E_f is above these limits, the owner or operator must either:
 9919 implement Option 1 in Section 2.2.5.1 of this Exhibit; or perform a RATA in
 9920 accordance with Option 2 in Section 2.2.5.2 of this Exhibit; or re-examine the
 9921 hourly data used for the flow-to-load or GHR analysis and recalculate E_f , after
 9922 excluding all non-representative hourly flow rates. If E_f is above these limits, the
 9923 owner or operator must either: implement Option 1 in Section 2.2.5.1 of this
 9924 Exhibit; perform a RATA in accordance with Option 2 in Section 2.2.5.2 of this
 9925 Exhibit; or (if applicable) re-examine the hourly data used for the flow-to-load or
 9926 GHR analysis and recalculate E_f , after excluding all non-representative hourly
 9927 flow rates, as provided in subsection (c) of this Section.

- 9928
- 9929 c) Recalculation of E_f . If the owner or operator did not exclude any hours within \pm
 9930 10 percent of L_{avg} from the original data analysis and chooses to recalculate E_f ,
 9931 the flow rates for the following hours are considered non-representative and may
 9932 be excluded from the data analysis:
- 9933
- 9934 1) Any hour in which the type of fuel combusted was different from the fuel
 9935 burned during the most recent normal-load RATA. For purposes of this
 9936 determination, the type of fuel is different if the fuel is in a different state
 9937 of matter (i.e., solid, liquid, or gas) than is the fuel burned during the
 9938 RATA or if the fuel is a different classification of coal (e.g., bituminous
 9939 versus sub-bituminous). Also, for units that co-fire different types of fuels,
 9940 if the reference RATA was done while co-firing, then hours in which a
 9941 single fuel was combusted may be excluded from the data analysis as
 9942 different fuel hours (and vice-versa for co-fired hours, if the reference
 9943 RATA was done while combusting only one type of fuel);
 - 9944
 - 9945 2) For a unit that is equipped with an SO₂ scrubber and which always
 9946 discharges its flue gases to the atmosphere through a single stack, any
 9947 hour in which the SO₂ scrubber was bypassed;
 - 9948
 - 9949 3) Any hour in which "ramping" occurred, i.e., the hourly load differed by
 9950 more than \pm 15.0 percent from the load during the preceding hour or the
 9951 subsequent hour;
 - 9952
 - 9953 4) For a unit with a multiple stack discharge configuration consisting of a
 9954 main stack and a bypass stack, any hour in which the flue gases were
 9955 discharged through both stacks;
 - 9956
 - 9957 5) If a normal-load flow RATA was performed and passed during the quarter
 9958 being analyzed, any hour prior to completion of that RATA; and
 - 9959
 - 9960 6) If a problem with the accuracy of the flow monitor was discovered during

9961 the quarter and was corrected (as evidenced by passing the abbreviated
 9962 flow-to-load test in Section 2.2.5.3 of this Exhibit), any hour prior to
 9963 completion of the abbreviated flow-to-load test.

9964
 9965 7) After identifying and excluding all non-representative hourly data in
 9966 accordance with subsections (c)(1) through (6) of this Section, the owner
 9967 or operator may analyze the remaining data a second time. At least 168
 9968 representative hourly ratios or GHR values must be available to perform
 9969 the analysis; otherwise, the flow-to-load (or GHR) analysis is not required
 9970 for that monitor for that calendar quarter.

9971
 9972 8) If, after re-analyzing the data, E_f meets the applicable limit in subsection
 9973 (b)(1), (b)(2), (b)(3), or (b)(4) of this Section, no further action is required.
 9974 If, however, E_f is still above the applicable limit, data from the monitor
 9975 will be declared out-of-control, beginning with the first unit operating
 9976 hour following the quarter in which E_f exceeded the applicable limit.
 9977 Alternatively, if a probationary calibration error test is performed and
 9978 passed according to Section 1.4(b)(3)(B) of this Appendix, data from the
 9979 monitor may be declared conditionally valid following the quarter in
 9980 which E_f exceeded the applicable limit. The owner or operator must then
 9981 either implement Option 1 in Section 2.2.5.1 of this Exhibit or Option 2 in
 9982 Section 2.2.5.2 of this Exhibit.

9983
 9984 2.2.5.1 Option 1
 9985

9986 Within 14 unit operating days of the end of the calendar quarter for which the E_f value is above
 9987 the applicable limit, investigate and troubleshoot the applicable flow monitors. Evaluate the
 9988 results of each investigation as follows:

- 9989
 9990 a) If the investigation fails to uncover a problem with the flow monitor, a RATA
 9991 must be performed in accordance with Option 2 in Section 2.2.5.2 of this Exhibit.
 9992
 9993 b) If a problem with the flow monitor is identified through the investigation
 9994 (including the need to re-linearize the monitor by changing the polynomial
 9995 coefficients or K factors), data from the monitor are considered invalid back to the
 9996 first unit operating hour after the end of the calendar quarter for which E_f was
 9997 above the applicable limit. If the option to use conditional data validation was
 9998 selected under Section 2.2.5(c)(8) of this Exhibit, all conditionally valid data will
 9999 be invalidated, back to the first unit operating hour after the end of the calendar
 10000 quarter for which E_f was above the applicable limit. Corrective actions must be
 10001 taken. All corrective actions (e.g., non-routine maintenance, repairs, major
 10002 component replacements, re-linearization of the monitor, etc.) must be
 10003 documented in the operation and maintenance records for the monitor. The owner

10004 or operator then must either complete the abbreviated flow-to-load test in Section
 10005 2.2.5.3 of this Exhibit, or, if the corrective action taken has required
 10006 relinearization of the flow monitor, must perform a 3-load RATA. The
 10007 conditional data validation procedures in Section 1.4(b)(3) of this Appendix may
 10008 be applied to the 3-load RATA.

10009
 10010 2.2.5.2 Option 2
 10011

10012 Perform a single-load RATA (at a load designated as normal under Section 6.5.2.1 of Exhibit A
 10013 to this Appendix) of each flow monitor for which E_f is outside of the applicable limit. If the
 10014 RATA is passed hands-off, in accordance with Section 2.3.2(c) of this Exhibit, no further action
 10015 is required and the out-of-control period for the monitor ends at the date and hour of completion
 10016 of a successful RATA, unless the option to use conditional data validation was selected under
 10017 Section 2.2.5(c)(8) of this Exhibit. In that case, all conditionally valid data from the monitor are
 10018 considered to be quality-assured, back to the first unit operating hour following the end of the
 10019 calendar quarter for which the E_f value was above the applicable limit. If the RATA is failed, all
 10020 data from the monitor will be invalidated, back to the first unit operating hour following the end
 10021 of the calendar quarter for which the E_f value was above the applicable limit. Data from the
 10022 monitor remain invalid until the required RATA has been passed. Alternatively, following a
 10023 failed RATA and corrective actions, the conditional data validation procedures of Section
 10024 1.4(b)(3) of this Appendix may be used until the RATA has been passed. If the corrective actions
 10025 taken following the failed RATA included adjustment of the polynomial coefficients or K factors
 10026 of the flow monitor, a 3-level RATA is required, except as otherwise specified in Section 2.3.1.3
 10027 of this Exhibit.

10028
 10029 2.2.5.3 Abbreviated Flow-to-Load Test
 10030

- 10031 a) The following abbreviated flow-to-load test may be performed after any
 10032 documented repair, component replacement, or other corrective maintenance to a
 10033 flow monitor (except for changes affecting the linearity of the flow monitor, such
 10034 as adjusting the flow monitor coefficients or K factors) to demonstrate that the
 10035 repair, replacement, or other maintenance has not significantly affected the
 10036 monitor's ability to accurately measure the stack gas volumetric flow rate. Data
 10037 from the monitoring system are considered invalid from the hour of
 10038 commencement of the repair, replacement, or maintenance until either the hour in
 10039 which the abbreviated flow-to-load test is passed, or the hour in which a
 10040 probationary calibration error test is passed following completion of the repair,
 10041 replacement, or maintenance and any associated adjustments to the monitor. If the
 10042 latter option is selected, the abbreviated flow-to-load test must be completed
 10043 within 168 unit operating hours of the probationary calibration error test (or, for
 10044 peaking units, within 30 unit operating days, if that is less restrictive). Data from
 10045 the monitor are considered to be conditionally valid (as defined in 40 CFR 72.2,
 10046 incorporated by reference in Section 225.140), beginning with the hour of the

10047 probationary calibration error test.

10048

10049 b) Operate the units in such a way as to reproduce, as closely as practicable, the

10050 exact conditions at the time of the most recent normal-load flow RATA. To

10051 achieve this, it is recommended that the load be held constant to within ± 10.0

10052 percent of the average load during the RATA and that the diluent gas (CO_2 or O_2)

10053 concentration be maintained within ± 0.5 percent CO_2 or O_2 of the average diluent

10054 concentration during the RATA. For common stacks, to the extent practicable, use

10055 the same combination of units and load levels that were used during the RATA.

10056 When the process parameters have been set, record a minimum of six and a

10057 maximum of 12 consecutive hourly average flow rates, using the flow monitors

10058 for which E_f was outside the applicable limit. For peaking units, a minimum of

10059 three and a maximum of 12 consecutive hourly average flow rates are required.

10060 Also record the corresponding hourly load values and, if applicable, the hourly

10061 diluent gas concentrations. Calculate the flow-to-load ratio (or GHR) for each

10062 hour in the test hour period, using Equation B-1 or B-1a. Determine E_h for each

10063 hourly flow- to-load ratio (or GHR), using Equation B-2 of this Exhibit and then

10064 calculate E_f , the arithmetic average of the E_h values.

10065

10066 c) The results of the abbreviated flow-to-load test will be considered acceptable, and

10067 no further action is required if the value of E_h does not exceed the applicable limit

10068 specified in Section 2.2.5 of this Exhibit. All conditionally valid data recorded by

10069 the flow monitor will be considered quality assured, beginning with the hour of

10070 the probationary calibration error test that preceded the abbreviated flow-to-load

10071 test (if applicable). However, if E_f is outside the applicable limit, all conditionally

10072 valid data recorded by the flow monitor (if applicable) will be considered invalid

10073 back to the hour of the probationary calibration error test that preceded the

10074 abbreviated flow-to-load test, and a single-load RATA is required in accordance

10075 with Section 2.2.5.2 of this Exhibit. If the flow monitor must be re-linearized,

10076 however, a 3-load RATA is required.

10077

10078 2.3 Semiannual and Annual Assessments

10079

10080 For each primary and redundant backup monitoring system, perform relative accuracy

10081 assessments either semiannually or annually, as specified in Section 2.3.1.1 or 2.3.1.2 of this

10082 Exhibit for the type of test and the performance achieved. This requirement applies as of the

10083 calendar quarter following the calendar quarter in which the monitoring system is provisionally

10084 certified. A summary chart showing the frequency with which a relative accuracy test audit must

10085 be performed, depending on the accuracy achieved, is located at the end of this Exhibit in Figure

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10088 2.3.1 Relative Accuracy Test Audit (RATA)

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2.3.1.1 Standard RATA Frequencies

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- a) Except for mercury monitoring systems, and as otherwise specified in Section 2.3.1.2 of this Exhibit, perform relative accuracy test audits semiannually, i.e., once every two successive QA operating quarters (as defined in 40 CFR 72.2, incorporated by reference in Section 225.140) for each primary and redundant backup flow monitor, CO₂ or O₂ diluent monitor used to determine heat input, moisture monitoring system. For each primary and redundant backup mercury concentration monitoring system and each sorbent trap monitoring system, RATAs must be performed annually, i.e., once every four successive QA operating quarters (as defined in 40 CFR 72.2). A calendar quarter that does not qualify as a QA operating quarter must be excluded in determining the deadline for the next RATA. No more than eight successive calendar quarters must elapse after the quarter in which a RATA was last performed without a subsequent RATA having been conducted. If a RATA has not been completed by the end of the eighth calendar quarter since the quarter of the last RATA, then the RATA must be completed within a 720 unit (or stack) operating hour grace period (as provided in Section 2.3.3 of this Exhibit) following the end of the eighth successive elapsed calendar quarter, or data from the CEMS will become invalid.
- b) The relative accuracy test audit frequency of a CEMS may be reduced, as specified in Section 2.3.1.2 of this Exhibit, for primary or redundant backup monitoring systems which qualify for less frequent testing. Perform all required RATAs in accordance with the applicable procedures and provisions in Sections 6.5 through 6.5.2.2 of Exhibit A to this Appendix and Sections 2.3.1.3 and 2.3.1.4 of this Exhibit.

2.3.1.2 Reduced RATA Frequencies

Relative accuracy test audits of primary and redundant backup CO₂ or O₂ diluent monitors used to determine heat input, moisture monitoring systems, flow monitors may be performed annually (i.e., once every four successive QA operating quarters, rather than once every two successive QA operating quarters) if any of the following conditions are met for the specific monitoring system involved:

- a) The relative accuracy during the audit of a CO₂ or O₂ diluent monitor used to determine heat input is ≤ 7.5 percent;
- b) The relative accuracy during the audit of a flow monitor is ≤ 7.5 percent at each operating level tested;
- c) For low flow (≤ 10.0 fps), as measured by the reference method during the RATA stacks/ducts, when the flow monitor fails to achieve a relative accuracy ≤ 7.5

10133 percent during the audit, but the monitor mean value, calculated using Equation
 10134 A-7 in Exhibit A to this Appendix and converted back to an equivalent velocity in
 10135 standard feet per second (fps), is within ± 1.5 fps of the reference method mean
 10136 value, converted to an equivalent velocity in fps;

10137
 10138 d) For a CO₂ or O₂ monitor, when the mean difference between the reference method
 10139 values from the RATA and the corresponding monitor values is within ± 0.7
 10140 percent CO₂ or O₂; and

10141
 10142 e) When the relative accuracy of a continuous moisture monitoring system is ≤ 7.5
 10143 percent or when the mean difference between the reference method values from
 10144 the RATA and the corresponding monitoring system values is within ± 1.0
 10145 percent H₂O.

10146
 10147 2.3.1.3 RATA Load (or Operating) Levels and Additional RATA Requirements
 10148

10149 a) For CO₂ or O₂ diluent monitors used to determine heat input, mercury
 10150 concentration monitoring systems, sorbent trap monitoring systems, moisture
 10151 monitoring systems, the required semiannual or annual RATA tests must be done
 10152 at the load level (or operating level) designated as normal under Section 6.5.2.1(d)
 10153 of Exhibit A to this Appendix. If two load levels (or operating levels) are
 10154 designated as normal, the required RATAs may be done at either load level (or
 10155 operating level).

10156
 10157 b) For flow monitors installed and bypass stacks, and for flow monitors that qualify
 10158 to perform only single-level RATAs under Section 6.5.2(e) of Exhibit A to this
 10159 Appendix, all required semiannual or annual relative accuracy test audits must be
 10160 single-load (or single-level) audits at the normal load (or operating level), as
 10161 defined in Section 6.5.2.1(d) of Exhibit A to this Appendix.

10162
 10163 c) For all other flow monitors, the RATAs must be performed as follows:
 10164

10165 1) An annual 2-load (or 2-level) flow RATA must be done at the two most
 10166 frequently used load levels (or operating levels), as determined under
 10167 Section 6.5.2.1(d) of Exhibit A to this Appendix, or (if applicable) at the
 10168 operating levels determined under Section 6.5.2(e) of Exhibit A to this
 10169 Appendix. Alternatively, a 3-load (or 3-level) flow RATA at the low, mid,
 10170 and high load levels (or operating levels), as defined under Section
 10171 6.5.2.1(b) of Exhibit A to this Appendix, may be performed in lieu of the
 10172 2-load (or 2-level) annual RATA.

10173
 10174 2) If the flow monitor is on a semiannual RATA frequency, 2-load (or 2-
 10175 level) flow RATAs and single-load (or single-level) flow RATAs at the

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normal load level (or normal operating level) may be performed alternately.

- 3) A single-load (or single-level) annual flow RATA may be performed in lieu of the 2-load (or 2-level) RATA if the results of an historical load data analysis show that in the time period extending from the ending date of the last annual flow RATA to a date that is no more than 21 days prior to the date of the current annual flow RATA, the unit (or combination of units, for a common stack) has operated at a single load level (or operating level) (low, mid, or high), for ≥ 85.0 percent of the time. Alternatively, a flow monitor may qualify for a single-load (or single-level) RATA if the 85.0 percent criterion is met in the time period extending from the beginning of the quarter in which the last annual flow RATA was performed through the end of the calendar quarter preceding the quarter of current annual flow RATA.
- 4) A 3-load (or 3-level) RATA, at the low-, mid-, and high-load levels (or operating levels), as determined under Section 6.5.2.1 of Exhibit A to this Appendix, must be performed at least once every twenty consecutive calendar quarters, except for flow monitors that are exempted from 3-load (or 3-level) RATA testing under Section 6.5.2(b) or 6.5.2(e) of Exhibit A to this Appendix.
- 5) A 3-load (or 3-level) RATA is required whenever a flow monitor is re-linearized, i.e., when its polynomial coefficients or K factors are changed, except for flow monitors that are exempted from 3-load (or 3-level) RATA testing under Section 6.5.2(b) or 6.5.2(e) of Exhibit A to this Appendix. For monitors so exempted under Section 6.5.2(b), a single-load flow RATA is required. For monitors so exempted under Section 6.5.2(e), either a single-level RATA or a 2-level RATA is required, depending on the number of operating levels documented in the monitoring plan for the unit.
- 6) For all multi-level flow audits, the audit points at adjacent load levels or at adjacent operating levels (e.g., mid and high) must be separated by no less than 25.0 percent of the "range of operation," as defined in Section 6.5.2.1 of Exhibit A to this Appendix.

d) A RATA of a moisture monitoring system must be performed whenever the coefficient, K factor or mathematical algorithm determined under Section 6.5.6 of Exhibit A to this Appendix is changed.

2.3.1.4 Number of RATA Attempts

10219
 10220 The owner or operator may perform as many RATA attempts as are necessary to achieve the
 10221 desired relative accuracy test audit frequencies. However, the data validation procedures in
 10222 Section 2.3.2 of this Exhibit must be followed.

10223
 10224 2.3.2 Data Validation
 10225

- 10226 a) A RATA must not commence if the monitoring system is operating out-of-control
 10227 with respect to any of the daily and quarterly quality assurance assessments
 10228 required by Sections 2.1 and 2.2 of this Exhibit or with respect to the additional
 10229 calibration error test requirements in Section 2.1.3 of this Exhibit.
- 10230
 10231 b) Each required RATA must be done according to subsection (b)(1), (b)(2) or (b)(3)
 10232 of this Section:
- 10233
 10234 1) The RATA may be done "cold", i.e., with no corrective maintenance,
 10235 repair, calibration adjustments, re-linearization or reprogramming of the
 10236 monitoring system prior to the test.
- 10237
 10238 2) The RATA may be done after performing only the routine or non-routine
 10239 calibration adjustments described in Section 2.1.3 of this Exhibit at the
 10240 zero and/or upscale calibration gas levels, but no other corrective
 10241 maintenance, repair, re-linearization or reprogramming of the monitoring
 10242 system. Trial RATA runs may be performed after the calibration
 10243 adjustments and additional adjustments within the allowable limits in
 10244 Section 2.1.3 of this Exhibit may be made prior to the RATA, as
 10245 necessary, to optimize the performance of the CEMS. The trial RATA
 10246 runs need not be reported, provided that they meet the specification for
 10247 trial RATA runs in Section 1.4(b)(3)(G)(v) of this Appendix. However, if,
 10248 for any trial run, the specification in Section (b)(3)(G)(v) of this Appendix
 10249 is not met, the trial run must be counted as an aborted RATA attempt.
- 10250
 10251 3) The RATA may be done after repair, corrective maintenance, re-
 10252 linearization or reprogramming of the monitoring system. In this case, the
 10253 monitoring system will be considered out-of-control from the hour in
 10254 which the repair, corrective maintenance, re-linearization or
 10255 reprogramming is commenced until the RATA has been passed.
 10256 Alternatively, the data validation procedures and associated timelines in
 10257 Sections 1.4(b)(3)(B) through (I) of this Appendix may be followed upon
 10258 completion of the necessary repair, corrective maintenance, re-
 10259 linearization or reprogramming. If the procedures in Section 1.4(b)(3) of
 10260 this Appendix are used, the words "quality assurance" apply instead of the
 10261 word "recertification".

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- c) Once a RATA is commenced, the test must be done hands-off. No adjustment of the monitor's calibration is permitted during the RATA test period, other than the routine calibration adjustments following daily calibration error tests, as described in Section 2.1.3 of this Exhibit. If a routine daily calibration error test is performed and passed just prior to a RATA (or during a RATA test period) and a mathematical correction factor is automatically applied by the DAHS, the correction factor must be applied to all subsequent data recorded by the monitor, including the RATA test data. For 2-level and 3-level flow monitor audits, no linearization or reprogramming of the monitor is permitted in between load levels.

- d) For single-load (or single-level) RATAs, if a daily calibration error test is failed during a RATA test period, prior to completing the test, the RATA must be repeated. Data from the monitor are invalidated prospectively from the hour of the failed calibration error test until the hour of completion of a subsequent successful calibration error test. The subsequent RATA must not be commenced until the monitor has successfully passed a calibration error test in accordance with Section 2.1.3 of this Exhibit. Notwithstanding these requirements, when ASTM D6784-02 (incorporated by reference under Section 225.140) or Method 29 in appendix A-8 to 40 CFR 60, incorporated by reference in Section 225.140, is used as the reference method for the RATA of a mercury CEMS, if a calibration error test of the CEMS is failed during a RATA test period, any test runs completed prior to the failed calibration error test need not be repeated; however, the RATA may not continue until a subsequent calibration error test of the mercury CEMS has been passed. For multiple-load (or multiple-level) flow RATAs, each load level (or operating level) is treated as a separate RATA (i.e., when a calibration error test is failed prior to completing the RATA at a particular load level (or operating level), only the RATA at that load level (or operating level) must be repeated; the results of any previously-passed RATAs at the other load levels (or operating levels) are unaffected, unless re-linearization of the monitor is required to correct the problem that caused the calibration failure, in which case a subsequent 3-load (or 3-level) RATA is required), except as otherwise provided in Section 2.3.1.3(c)(5) of this Exhibit.

- e) For a RATA performed using the option in subsection (b)(1) or (b)(2) of this Section, if the RATA is failed (that is, if the relative accuracy exceeds the applicable specification in Section 3.3 of Exhibit A to this Appendix) or if the RATA is aborted prior to completion due to a problem with the CEMS, then the CEMS is out-of-control and all emission data from the CEMS are invalidated prospectively from the hour in which the RATA is failed or aborted. Data from the CEMS remain invalid until the hour of completion of a subsequent RATA that meets the applicable specification in Section 3.3 of Exhibit A to this Appendix. If the option in subsection (b)(3) of this Section to use the data validation

procedures and associated timelines in Sections 1.4(b)(3)(B) through(b)(3)(I) of this Appendix has been selected, the beginning and end of the out-of-control period must be determined in accordance with Section 1.4(b)(3)(G)(i) and (ii) of this Appendix. Note that when a RATA is aborted for a reason other than monitoring system malfunction (see subsection (g) of this Section), this does not trigger an out-of-control period for the monitoring system.

- f) For a 2-level or 3-level flow RATA, if, at any load level (or operating level), a RATA is failed or aborted due to a problem with the flow monitor, the RATA at that load level (or operating level) must be repeated. The flow monitor is considered out-of-control and data from the monitor are invalidated from the hour in which the test is failed or aborted and remain invalid until the passing of a RATA at the failed load level (or operating level), unless the option in subsection (b)(3) of this Section to use the data validation procedures and associated timelines in Section 1.4(b)(3)(B) through (b)(3)(I) of this Appendix has been selected, in which case the beginning and end of the out-of-control period must be determined in accordance with Section 1.4(b)(3)(G)(i) and (ii) of this Appendix. Flow RATA(s) that were previously passed at the other load levels (or operating levelss) do not have to be repeated unless the flow monitor must be re-linearized following the failed or aborted test. If the flow monitor is re-linearized, a subsequent 3-load (or 3-level) RATA is required, except as otherwise provided in Section 2.3.1.3(c)(5) of this Exhibit.
- g) For each monitoring system, report the results of all completed and partial RATAs that affect data validation (i.e., all completed, passed RATAs; all completed, failed RATAs; and all RATAs aborted due to a problem with the CEMS, including trial RATA runs counted as failed test attempts under subsection (b)(2) of this Section or under Section 1.4(b)(3)(G)(vi)) in the quarterly report required under 40 CFR 75.64, incorporated by reference in Section 225.140. Note that RATA attempts that are aborted or invalidated due to problems with the reference method or due to operational problems with the affected units need not be reported. Such runs do not affect the validation status of emission data recorded by the CEMS. However, a record of all RATAs, trial RATA runs and RATA attempts (whether reported or not) must be kept on-site as part of the official test log for each monitoring system.
- h) Each time that a hands-off RATA of a mercury concentration monitoring system, a sorbent trap monitoring system, or a flow monitor is passed, perform a bias test in accordance with Section 7.4.4 of Exhibit A to this Appendix.
- i) Failure of the bias test does not result in the monitoring system being out-of-control.

2.3.3 RATA Grace Period

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 10350 a) The owner or operator has a grace period of 720 consecutive unit operating hours,
 10351 as defined in 40 CFR 72.2, incorporated by reference in Section 225.140 (or, for
 10352 CEMS installed on common stacks or bypass stacks, 720 consecutive stack
 10353 operating hours, as defined in 40 CFR 72.2), in which to complete the required
 10354 RATA for a particular CEMS whenever:
 10355
 10356 1) A required RATA has not been performed by the end of the QA operating
 10357 quarter in which it is due; or
 10358
 10359 2) A required 3-load flow RATA has not been performed by the end of the
 10360 calendar quarter in which it is due.
 10361
 10362 b) The grace period will begin with the first unit (or stack) operating hour following
 10363 the calendar quarter in which the required RATA was due. Data validation during
 10364 a RATA grace period must be done in accordance with the applicable provisions
 10365 in Section 2.3.2 of this Exhibit.
 10366
 10367 c) If, at the end of the 720 unit (or stack) operating hour grace period, the RATA has
 10368 not been completed, data from the monitoring system will be invalid, beginning
 10369 with the first unit operating hour following the expiration of the grace period.
 10370 Data from the CEMS remain invalid until the hour of completion of a subsequent
 10371 hands-off RATA. The deadline for the next test will be either two QA operating
 10372 quarters (if a semiannual RATA frequency is obtained) or four QA operating
 10373 quarters (if an annual RATA frequency is obtained) after the quarter in which the
 10374 RATA is completed, not to exceed eight calendar quarters.
 10375
 10376 d) When a RATA is done during a grace period in order to satisfy a RATA
 10377 requirement from a previous quarter, the deadline for the next RATA must be
 10378 determined as follows:
 10379
 10380 1) If the grace period RATA qualifies for a reduced, (i.e., annual), RATA
 10381 frequency the deadline for the next RATA will be set at three QA
 10382 operating quarters after the quarter in which the grace period test is
 10383 completed.
 10384
 10385 2) If the grace period RATA qualifies for the standard, (i.e., semiannual),
 10386 RATA frequency the deadline for the next RATA will be set at two QA
 10387 operating quarters after the quarter in which the grace period test is
 10388 completed.
 10389
 10390 3) Notwithstanding these requirements, no more than eight successive

calendar quarters must elapse after the quarter in which the grace period test is completed, without a subsequent RATA having been conducted.

2.4 Recertification, Quality Assurance, and RATA Frequency (Special Considerations)

- a) When a significant change is made to a monitoring system such that recertification of the monitoring system is required in accordance with Section 1.4(b) of this Appendix, a recertification test (or tests) must be performed to ensure that the CEMS continues to generate valid data. In all recertifications, a RATA will be one of the required tests; for some recertifications, other tests will also be required. A recertification test may be used to satisfy the quality assurance test requirement of this Exhibit. For example, if, for a particular change made to a CEMS, one of the required recertification tests is a linearity check and the linearity check is successful, then, unless another recertification event occurs in that same QA operating quarter, it would not be necessary to perform an additional linearity test of the CEMS in that quarter to meet the quality assurance requirement of Section 2.2.1 of this Exhibit. For this reason, EPA recommends that owners or operators coordinate component replacements, system upgrades, and other events that may require recertification, to the extent practicable, with the periodic quality assurance testing required by this Exhibit. When a quality assurance test is done for the dual purpose of recertification and routine quality assurance, the applicable data validation procedures in Section 1.4(b)(3) must be followed.
- b) Except as provided in Section 2.3.3 of this Exhibit, whenever a passing RATA of a gas monitor is performed, or a passing 2-load (or 2-level) RATA or a passing 3-load (or 3-level) RATA of a flow monitor is performed (irrespective of whether the RATA is done to satisfy a recertification requirement or to meet the quality assurance requirements of this Exhibit, or both), the RATA frequency (semi-annual or annual) must be established based upon the date and time of completion of the RATA and the relative accuracy percentage obtained. For 2-load (or 2-level) and 3-load (or 3-level) flow RATAs, use the highest percentage relative accuracy at any of the loads (or levels) to determine the RATA frequency. The results of a single-load (or single-level) flow RATA may be used to establish the RATA frequency when the single-load (or single-level) flow RATA is specifically required under Section 2.3.1.3(b) of this Exhibit or when the single-load (or single-level) RATA is allowed under Section 2.3.1.3(c) of this Exhibit for a unit that has operated at one load level (or operating level) for ≥ 85.0 percent of the time since the last annual flow RATA. No other single-load (or single-level) flow RATA may be used to establish an annual RATA frequency; however, a 2-load or 3-load (or a 2-level or 3-level) flow RATA may be performed at any time or in place of any required single-load (or single-level) RATA, in order to establish an annual RATA frequency.

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2.5 Other Audits

Affected units may be subject to relative accuracy test audits at any time. If a monitor or continuous emission monitoring system fails the relative accuracy test during the audit, the monitor or continuous emission monitoring system will be considered to be out-of-control beginning with the date and time of completion of the audit, and continuing until a successful audit test is completed following corrective action.

2.6 System Integrity Checks for Mercury Monitors

For each mercury concentration monitoring system (except for a mercury monitor that does not have a converter), perform a single-point system integrity check weekly, i.e., at least once every 168 unit or stack operating hours, using a NIST-traceable source of oxidized mercury. Perform this check using a mid- or high-level gas concentration, as defined in Section 5.2 of Exhibit A to this Appendix. The performance specifications in subsection (3) of Section 3.2 of Exhibit A to this Appendix must be met, otherwise the monitoring system is considered out-of-control, from the hour of the failed check until a subsequent system integrity check is passed. If a required system integrity check is not performed and passed within 168 unit or stack operating hours of last successful check, the monitoring system will also be considered out of control, beginning with the 169th unit or stack operating hour after the last successful check, and continuing until a subsequent system integrity check is passed. This weekly check is not required if the daily calibration assessments in Section 2.1.1 of this Exhibit are performed using a NIST-traceable source of oxidized mercury.

[Note: The following TABLE/FORM is too wide to be displayed on one screen. You must print it for a meaningful review of its contents. The table has been divided into multiple pieces with each piece containing information to help you assemble a printout of the table. The information for each piece includes: (1) a three line message preceding the tabular data showing by line # and character # the position of the upper left-hand corner of the piece and the position of the piece within the entire table; and (2) a numeric scale following the tabular data displaying the character positions.]

Figure 1 for Exhibit B of Appendix B Part 75. – Qaulity Assurance Test Requirements

<u>Test</u>	<u>Basic QA test frequency requirements [FN*]</u>				
	<u>Daily</u> <u>[FN*]</u>	<u>Weekly</u>	<u>Quarterly</u> <u>[FN*]</u>	<u>Semiannual</u> <u>[FN*]</u>	<u>Annual</u>
<u>Calibration Error Test (2 pt.)</u>	/				

<u>Interference Check (flow)</u>	/	
<u>Flow-to-Load Ratio</u>		/
<u>Leak Check (DP flow monitors)</u>		/
<u>Linearity Check or System Integrity Check [FN**] (3 pt.)</u>		/
<u>Single-point System Integrity Check [FN**]</u>	/	
<u>RATA (SO₂, NO_x, CO₂, O₂, H₂O) [FN1]</u>		/
<u>RATA (All Hg monitoring systems)</u>		/
<u>RATA (flow) [FN1] [FN2]</u>		/

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[FN*] "Daily" means operating days, only. "Weekly" means once every 168 unit or stack operating hours. "Quarterly" means once every QA operating quarter. "Semiannual" means once every two QA operating quarters. "Annual" means once every four QA operating quarters. [FN**] The system integrity check applies only to Hg monitors with converters. The single-point weekly system integrity check is not required if daily calibrations are performed using a NIST-traceable source of oxidized Hg. The 3-point quarterly system integrity check is not required if a linearity check is performed.

[FN1] Conduct RATA annually (i.e., once every four QA operating quarters), if monitor meets accuracy requirements to qualify for less frequent testing. [FN2] For flow monitors installed on peaking units, bypass stacks, or units that qualify for single-level RATA testing under Section 6.5.2(e) of this part, conduct all RATAs at a single, normal load (or operating level). For other flow monitors, conduct annual RATAs at two load levels (or operating levels). Alternating single-load and 2-load (or single-level and 2-level) RATAs may be done if a monitor is on a semiannual frequency. A single-load (or single-level) RATA may be done in lieu of a 2-load (or 2-level) RATA if, since the last annual flow RATA, the unit has operated at one load level (or operating level) for ≥85.0 percent of the time. A 3-level RATA is required at least once every five calendar years and whenever a flow monitor is re-linearized, except for flow monitors exempted from 3-level RATA testing under Section 6.5.2(b) or 6.5.2(e) of Exhibit A to this Appendix.

Figure 2 for Exhibit B of Appendix B – Relative Accuracy Test Frequency Incentive System

<u>RATA</u>	<u>Semiannual [FNW] (percent)</u>	<u>Annual [FNW]</u>
<u>SO₂ or NO_x [FNY]</u>	<u>7.5% < RA ≤10.0% or ± 15.0 ppm [FNX]</u>	<u>RA ≤7.5% or ± 12.0 ppm [FNX].</u>
<u>SO₂-diluent</u>	<u>7.5% < RA ≤10.0% or ± 0.030 lb/mmBtu [FNX]</u>	<u>RA ≤7.5% or ± 0.025 lb/mmBtu =G5X.</u>
<u>NO_x-diluent</u>	<u>7.5% < RA ≤10.0% or ± 0.020 lb/mmBtu [FNX]</u>	<u>RA ≤7.5% or ± 0.015 lb/mmBtu [FNX].</u>
<u>Flow</u>	<u>7.5% < RA ≤10.0% or ± 2.0 fps [FNX]</u>	<u>RA ≤7.5% or ± 1.5 fps [FNX].</u>
<u>CO₂ or O₂</u>	<u>7.5% < RA ≤10.0% or ± 1.0 CO₂/O₂ [FNX]</u>	<u>RA ≤7.5% or ± 0.7% CO₂/O₂ [FNX].</u>
<u>Hg [FNX]</u> <u><<mu>>g/scm</u>	<u>N/A</u>	<u>RA < 20.0% or ± 1.0 [FNX].</u>
<u>Moisture</u>	<u>7.5% < RA ≤10.0% or ± 1.5% H₂O [FNX]</u>	<u>RA ≤7.5% or ± 1.0% H₂O [FNX].</u>

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 10494 [FNW] The deadline for the next RATA is the end of the second (if semiannual) or fourth (if
 10495 annual) successive QA operating quarter following the quarter in which the CEMS was last
 10496 tested. Exclude calendar quarters with fewer than 168 unit operating hours (or, for common
 10497 stacks and bypass stacks, exclude quarters with fewer than 168 stack operating hours) in
 10498 determining the RATA deadline. For SO₂ monitors, QA operating quarters in which only
 10499 very low sulfur fuel as defined in 40 CFR 72.2, incorporated by reference in Section
 10500 225.140, is combusted may also be excluded. However, the exclusion of calendar quarters is
 10501 limited as follows: the deadline for the next RATA will be no more than 8 calendar quarters
 10502 after the quarter in which a RATA was last performed. [FNX] The difference between
 10503 monitor and reference method mean values applies to moisture monitors, CO₂, and O₂
 10504 monitors, low emitters of SO₂, NO_x, or H_g, or and low flow, only. The specifications for H_g
 10505 monitors also apply to sorbent trap monitoring systems. [FNY] A NO_x concentration
 10506 monitoring system used to determine NO_x mass emissions under 40 CFR 75.71,
 10507 incorporated by reference in Section 225.140.

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Exhibit C to Appendix B--Conversion Procedures

1. Applicability

Use the procedures in this Exhibit to convert measured data from a monitor or continuous emission monitoring system into the appropriate units of the standard.

2. Procedures for Heat Input

Use the following procedures to compute heat input rate to an affected unit (in mmBtu/hr or mmBtu/day):

2.1

Calculate and record heat input rate to an affected unit on an hourly basis. The owner or operator may choose to use the provisions specified in 40 CFR 75.16(e), incorporated by reference in Section 225.140, in conjunction with the procedures provided in Sections 2.4 through 2.4.2 to apportion heat input among each unit using the common stack or common pipe header.

2.2

For an affected unit that has a flow monitor (or approved alternate monitoring system under subpart E of 40 CFR 75, incorporated by reference in Section 225.140, for measuring volumetric flow rate) and a diluent gas (O₂ or CO₂) monitor, use the recorded data from these monitors and one of the following equations to calculate hourly heat input rate (in mmBtu/hr).

2.2.1

When measurements of CO₂ concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F_c} \frac{\%CO_{2w}}{100} \quad \text{(Equation F - 15)}$$

Where:

- HI ≡ Hourly heat input rate during unit operation, mmBtu/hr.
- Q_w ≡ Hourly average volumetric flow rate during unit operation, wet basis, scfh.
- F_c ≡ Carbon-based F-factor, listed in Section 3.3.5 of appendix F to 40 CFR 75 for each fuel, scf/mmBtu.
- %CO_{2w} ≡ Hourly concentration of CO₂ during unit operation, percent

CO₂ wet basis.

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2.2.2

When measurements of CO₂ concentration are on a dry basis, use the following equation:

$$HI = Q_h \left[\frac{(100 - \%H_2O)}{100F_c} \right] \left(\frac{\%CO_{2d}}{100} \right) \quad \text{(Equation F-16)}$$

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Where:

- HI ≡ Hourly heat input rate during unit operation, mmBtu/hr.
- Q_h ≡ Hourly average volumetric flow rate during unit operation, wet basis, scfh.
- F_c ≡ Carbon-based F-factor, listed in Section 3.3.5 of appendix F to 40 CFR 75 for each fuel, scf/mmBtu.
- %CO_{2d} ≡ Hourly concentration of CO₂ during unit operation, percent CO₂ wet basis.
- %H₂O ≡ Moisture content of gas in the stack, percent.

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2.2.3

When measurements of O₂ concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F} \frac{[(20.9/100)(100 - \%H_2O) - \%O_{2w}]}{20.9} \quad \text{(Equation F-17)}$$

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Where:

- HI ≡ Hourly heat input rate during unit operation, mmBtu/hr.
- Q_w ≡ Hourly average volumetric flow rate during unit operation, wet basis, scfh.
- F ≡ Carbon-based F-factor, listed in Section 3.3.5 of appendix F to 40 CFR 75 for each fuel, scf/mmBtu.
- %O_{2w} ≡ Hourly concentration of O₂ during unit operation, percent O₂ wet basis.
- %H₂O ≡ Hourly average stack moisture content, percent by volume.

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2.2.4

When measurements of O₂ concentration are on a dry basis, use the following equation:

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$$HI = Q_w \left[\frac{(100 - \%H_2O)}{100F} \right] \left[\frac{(20.9 - \%O_{2d})}{20.9} \right] \quad \text{(Equation F-18)}$$

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Where:

- HI ≡ Hourly heat input rate during unit operation, mmBtu/hr.
- Q_w ≡ Hourly average volumetric flow during unit operation, wet basis, scfh.
- F ≡ Dry basis F-factor, listed in Section 3.3.5 of appendix F to 40 CFR 75 for each fuel, dscf/mmBtu.
- %H₂O ≡ Moisture content of the stack gas, percent.
- %O_{2d} ≡ Hourly concentration of O₂ during unit operation, percent O₂ dry basis.

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2.3

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Heat Input Summation (for Heat Input Determined Using a Flow Monitor and Diluent Monitor)

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2.3.1

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Calculate total quarterly heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

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$$HI_q = \sum_{hour=1}^n HI_i t_i \quad \text{(Equation F-18a)}$$

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Where:

- HI_q ≡ Total heat input for the quarter, mmBtu.
- HI_i ≡ Hourly heat input rate during unit operation, using Equation F-15, F-16, F-17, or F-18, mmBtu/hr.
- t_i ≡ Hourly operating time for the unit or common stack, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

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2.3.2

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Calculate total cumulative heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

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$$HI_c = \frac{\sum_{q=1}^{\text{the_current_quarter}} HI_q}{\text{the_current_quarter}} \quad \text{(Equation F-18b)}$$

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Where:

HI_c ≡ Total heat input for the quarter, mmBtu.

HI_q ≡ Total heat input for the quarter, mmBtu.

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2.4 Heat Input Rate Apportionment for Units Sharing a Common Stack or Pipe

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2.4.1

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Where applicable, the owner or operator of an affected unit that determines heat input rate at the unit level by apportioning the heat input monitored at a common stack or common pipe using megawatts must apportion the heat input rate using the following equation:

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$$HI_i = HI_{CS} \left(\frac{t_{CS}}{t_i} \right) \left[\frac{MW_i t_i}{\sum_{i=1}^n MW_i t_i} \right] \quad \text{(Equation F-21a)}$$

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Where:

HI_i ≡ Heat input rate for a unit, mmBtu/hr.

HI_{CS} ≡ Heat input rate at the common stack or pipe, mmBtu/hr.

MW_i ≡ Gross electrical output, MWe.

t_i ≡ Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CS} ≡ Common stack or common pipe operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n ≡ Total number of units using the common stack or pipe.

i ≡ Designation of a particular unit.

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2.4.2

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 10612 Where applicable, the owner or operator of an affected unit that determines the heat input rate at
 10613 the unit level by apportioning the heat input rate monitored at a common stack or common pipe
 10614 using steam load must apportion the heat input rate using the following equation:
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$$HI_i = HI_{CS} \left(\frac{t_{CS}}{t_i} \right) \left[\frac{SF_i t_i}{\sum_{i=1}^n SF_i t_i} \right] \quad \text{(Equation F-21b)}$$

10617
 10618 Where:
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- HI_i ≡ Heat input rate for a unit, mmBtu/hr.
- HI_{CS} ≡ Heat input rate at the common stack or pipe, mmBtu/hr.
- SF ≡ Gross steam load, lb/hr, or mmBtu/hr.
- t_i ≡ Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).
- t_{CS} ≡ Common stack or common pipe operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).
- n ≡ Total number of units using the common stack or pipe.
- i ≡ Designation of a particular unit.

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 10621 2.5 Heat Input Rate Summation for Units with Multiple Stacks or Pipes
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10623 The owner or operator of an affected unit that determines the heat input rate at the unit level by
 10624 summing the heat input rates monitored at multiple stacks or multiple pipes must sum the heat
 10625 input rates using the following equation:
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$$HI_{Unit} = \frac{\sum_{s=1}^n HI_s t_s}{t_{Unit}} \quad \text{(Equation F-21c)}$$

10628
 10629 Where:
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- HI_{Unit} ≡ Heat input rate for a unit, mmBtu/hr.

- $\underline{HI_s}$ = Heat input rate for the individual stack, duct, or pipe, mmBtu/hr.
- $\underline{t_{Unit}}$ = Unit operating time, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).
- $\underline{t_s}$ = Operating time for the individual stack or pipe, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).
- \underline{s} = Designation for a particular stack, duct, or pipe.

3. Procedure for Converting Volumetric Flow to STP

Use the following equation to convert volumetric flow at actual temperature and pressure to standard temperature and pressure.

$$\underline{F_{STP} = F_{Actual} \left(\frac{T_{Std}}{T_{Stack}} \right) \left(\frac{P_{Stack}}{P_{Std}} \right)} \quad \text{(Equation F-22)}$$

Where:

- $\underline{F_{STP}}$ = Flue gas volumetric flow rate at standard temperature and pressure, scfh.
- $\underline{F_{Actual}}$ = Flue gas volumetric flow rate at actual temperature and pressure, acfh.
- $\underline{T_{Std}}$ = Standard temperature = 528 degreesR.
- $\underline{T_{Stack}}$ = Flue gas temperature at flow monitor location, degreesR, where degreesR = 460 + degreesF.
- $\underline{P_{Stack}}$ = The absolute flue gas pressure = barometric pressure at the flow monitor location + flue gas static pressure, inches of mercury.
- $\underline{P_{Std}}$ = The absolute flue gas pressure = barometric pressure at the flow monitor location + flue gas static pressure, inches of mercury.

4. Procedures for Mercury Mass Emissions.

4.1

Use the procedures in this Section to calculate the hourly mercury mass emissions (in ounces) at each monitored location for the affected unit or group of units that discharge through a common stack.

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4.1.1

To determine the hourly mercury mass emissions when using a mercury concentration monitoring system that measures on a wet basis and a flow monitor, use the following equation:

$$\underline{M_h = KC_h Q_h t_h} \quad \text{(Equation F-28)}$$

Where:

- M_h ≡ Mercury mass emissions for the hour rounded off to three decimal places (ounces).
- K ≡ Units conversion constant, 9.978 x 10⁻¹⁰ oz-scm/μg-scf.
- C_h ≡ Hourly mercury concentration, wet basis, adjusted for bias if the bias-test procedures in Exhibit A to this Appendix show that a bias-adjustment factor is necessary, (μg/wscm).
- Q_h ≡ Hourly stack gas volumetric flow rate, adjusted for bias, where the bias-test procedures in Exhibit A to this Appendix shows a bias-adjustment factor is necessary, (scfh).
- t_h ≡ Unit or stack operating time, as defined in 40 CFR 72.2, (hr.).

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4.1.2

To determine the hourly mercury mass emissions when using a mercury concentration monitoring system that measures on a dry basis or a sorbent trap monitoring system and a flow monitor, use the following equation:

$$\underline{M_h = KC_h Q_h t_h (1 - B_{ws})} \quad \text{(Equation F-29)}$$

Where:

- M_h ≡ mercury mass emissions for the hour rounded off to three decimal places (ounces).
- K ≡ Units conversion constant, 9.978 x 10⁻¹⁰ oz-scm/μg-scf.
- C_h ≡ Hourly mercury concentration, dry basis, adjusted for bias if the bias-test procedures in Exhibit A to this Appendix show that a bias-adjustment factor is necessary, (μg/dscm). For sorbent trap systems, a single value of C_h (i.e., a flow-proportional average concentration for the data collection period) is applied to each hour in the data collection period for a particular pair of traps.

$Q_h \equiv$ Hourly stack gas volumetric flow rate, adjusted for bias, where the bias-test procedures in Exhibit A to this Appendix shows a bias-adjustment factor is necessary, (scfh).

$B_{ws} \equiv$ Moisture fraction of the stack gas expressed as a decimal (equal to %H₂O 100)

$t_h \equiv$ Unit or stack operating time as defined in 40 CFR 72.2, (hr.).

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4.1.3

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10673 For units that are demonstrated under Section 1.15(d) of this Appendix to emit less than 464
 10674 ounces of mercury per year, and for which the owner or operator elects not to continuously
 10675 monitor the mercury concentration, calculate the hourly mercury mass emissions using Equation
 10676 F-28 in Section 4.1.1 of this Exhibit, except that "C_h" will be the applicable default mercury
 10677 concentration from Section 1.15(c), (d), or (e) of this Appendix, expressed in µg/scm. Correction
 10678 for the stack gas moisture content is not required when this methodology is used.

10679

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4.2

10681

10682 Use the following equation to calculate quarterly and year-to-date mercury mass emissions in
 10683 ounces:

10684

$$M_{time_period} = \sum_{h=1}^n M_h \quad \text{(Equation F-30)}$$

10685

10686

10687

Where:

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$M_{time_period} \equiv$ Mercury mass emissions for the given time period, i.e., quarter or year-to-date rounded to the nearest thousandth, (ounces).

$M_h \equiv$ Mercury mass emissions for the hour rounded to three decimal places (ounces).

$n \equiv$ The number of hours in the given time period (quarter or year-to-date).

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10690 4.3 If heat input rate monitoring is required, follow the applicable procedures for heat input
 10691 apportionment and summation in Sections 2.3, 2.4 and 2.5 of this Exhibit.

10692

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5. Moisture Determination From Wet and Dry O₂ Readings

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10695 If a correction for the stack gas moisture content is required in any of the emissions or heat input
 10696 calculations described in this Exhibit, and if the hourly moisture content is determined from wet-
 10697 and dry-basis O₂ readings, use Equation F-31 to calculate the percent moisture, unless a "K"
 10698 factor or other mathematical algorithm is developed as described in Section 6.5.6(a) of Exhibit A

10699 to this Appendix:

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10701
$$\%H_2O = \frac{(O_{2d} - O_{2w})}{O_{2d}} \times 100 \quad \text{(Equation F-31)}$$

10702

10703

10704

Where:

- $\%H_2O$ = Hourly average stack gas moisture content, percent H₂O
- O_{2d} = Dry-basis hourly average oxygen concentration, percent O₂
- O_{2w} = Wet-basis hourly average oxygen concentration, percent O₂

10705

10706 **Exhibit D to Appendix B – Quality Assurance and Operating Procedures for Sorbent Trap**
 10707 **Monitoring Systems**

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1.0 Scope and Application

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This Exhibit specifies sampling, and analytical, and quality-assurance criteria and procedures for the performance-based monitoring of vapor-phase mercury (Hg) emissions in combustion flue gas streams, using a sorbent trap monitoring system (as defined in Section 225.130). The principle employed is continuous sampling using in-stack sorbent media coupled with analysis of the integrated samples. The performance-based approach of this Exhibit allows for use of various suitable sampling and analytical technologies while maintaining a specified and documented level of data quality through performance criteria. Persons using this Exhibit should have a thorough working knowledge of Methods 1, 2, 3, 4 and 5 in appendices A-1 through A-3 to 40 CFR 60, incorporated by reference in Section 225.140, as well as the determinative technique selected for analysis.

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1.1 Analytes

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The analyte measured by these procedures and specifications is total vapor-phase mercury in the flue gas, which represents the sum of elemental mercury (Hg⁰, CAS Number 7439-97-6) and oxidized forms of mercury, in mass concentration units of micrograms per dry standard cubic meter (µg/dscm).

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1.2 Applicability

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These performance criteria and procedures are applicable to monitoring of vapor-phase mercury emissions under relatively low-dust conditions (i.e., sampling in the stack after all pollution control devices), from coal-fired electric utility steam generators which are subject to Sections 1.14 through 1.18 of Appendix B. Individual sample collection times can range from 30 minutes to several days in duration, depending on the mercury concentration in the stack. The monitoring system must achieve the performance criteria specified in Section 8 of this Exhibit and the sorbent media capture ability must not be exceeded. The sampling rate must be maintained at a

10738 constant proportion to the total stack flow rate to ensure representativeness of the sample
 10739 collected. Failure to achieve certain performance criteria will result in invalid mercury emissions
 10740 monitoring data.

10741

10742 2.0 Principle

10743

10744 Known volumes of flue gas are extracted from a stack or duct through paired, in-stack, pre-
 10745 spiked sorbent media traps at an appropriate nominal flow rate. Collection of mercury on the
 10746 sorbent media in the stack mitigates potential loss of mercury during transport through a
 10747 probe/sample line. Paired train sampling is required to determine measurement precision and
 10748 verify acceptability of the measured emissions data.

10749

10750 The sorbent traps are recovered from the sampling system, prepared for analysis, as needed, and
 10751 analyzed by any suitable determinative technique that can meet the performance criteria. A
 10752 section of each sorbent trap is spiked with Hg⁰ prior to sampling. This section is analyzed
 10753 separately and the recovery value is used to correct the individual mercury sample for
 10754 measurement bias.

10755

10756 3.0 Clean Handling and Contamination

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10758 To avoid mercury contamination of the samples, special attention should be paid to cleanliness
 10759 during transport, field handling, sampling, recovery, and laboratory analysis, as well as during
 10760 preparation of the sorbent cartridges. Collection and analysis of blank samples (field, trip, lab) is
 10761 useful in verifying the absence of contaminant mercury.

10762

10763 4.0 Safety

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10765 4.1 Site hazards

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10767 Site hazards must be thoroughly considered in advance of applying these
 10768 procedures/specifications in the field; advance coordination with the site is critical to understand
 10769 the conditions and applicable safety policies. At a minimum, portions of the sampling system
 10770 will be hot, requiring appropriate gloves, long sleeves, and caution in handling this equipment.

10771

10772 4.2 Laboratory safety policies

10773

10774 Laboratory safety policies should be in place to minimize risk of chemical exposure and to
 10775 properly handle waste disposal. Personnel must wear appropriate laboratory attire according to a
 10776 Chemical Hygiene Plan established by the laboratory.

10777

10778 4.3 Toxicity or carcinogenicity

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10780 The toxicity or carcinogenicity of any reagents used must be considered. Depending upon the

10781 sampling and analytical technologies selected, this measurement may involve hazardous
 10782 materials, operations, and equipment and this Exhibit does not address all of the safety problems
 10783 associated with implementing this approach. It is the responsibility of the user to establish
 10784 appropriate safety and health practices and determine the applicable regulatory limitations prior
 10785 to performance. Any chemical should be regarded as a potential health hazard and exposure to
 10786 these compounds should be minimized. Chemists should refer to the Material Safety Data Sheet
 10787 (MSDS) for each chemical used.

10788
 10789 4.4 Wastes

10790
 10791 Any wastes generated by this procedure must be disposed of according to a hazardous materials
 10792 management plan that details and tracks various waste streams and disposal procedures.

10793
 10794 5.0 Equipment and Supplies

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 10796 The following list is presented as an example of key equipment and supplies likely required to
 10797 perform vapor-phase mercury monitoring using a sorbent trap monitoring system. It is
 10798 recognized that additional equipment and supplies may be needed. Collection of paired samples
 10799 is required. Also required are a certified stack gas volumetric flow monitor that meets the
 10800 requirements of Section 1.2 to this Appendix and an acceptable means of correcting for the stack
 10801 gas moisture content, i.e., either by using data from a certified continuous moisture monitoring
 10802 system or by using an approved default moisture value (see 40 CFR 75.11(b), incorporated by
 10803 reference in Section 225.140).

10804
 10805 5.1 Sorbent Trap Monitoring System

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 10807 A typical sorbent trap monitoring system is shown in Figure K-1. The monitoring system must
 10808 include the following components:

10809
 10810 5.1.1 Sorbent Traps

10811
 10812 The sorbent media used to collect mercury must be configured in a trap with three distinct and
 10813 identical segments or sections, connected in series, that are amenable to separate analyses.
 10814 Section 1 is designated for primary capture of gaseous mercury. Section 2 is designated as a
 10815 backup section for determination of vapor-phase mercury breakthrough. Section 3 is designated
 10816 for QA/QC purposes where this section must be spiked with a known amount of gaseous Hg⁰
 10817 prior to sampling and later analyzed to determine recovery efficiency. The sorbent media may be
 10818 any collection material (e.g., carbon, chemically-treated filter, etc.) capable of quantitatively
 10819 capturing and recovering for subsequent analysis, all gaseous forms of mercury for the intended
 10820 application. Selection of the sorbent media must be based on the material's ability to achieve the
 10821 performance criteria contained in Section 8 of this Exhibit as well as the sorbent's vapor-phase
 10822 mercury capture efficiency for the emissions matrix and the expected sampling duration at the
 10823 test site. The sorbent media must be obtained from a source that can demonstrate the quality

10824 assurance and control necessary to ensure consistent reliability. The paired sorbent traps are
10825 supported on a probe (or probes) and inserted directly into the flue gas stream.

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5.1.2 Sampling Probe Assembly

10828

10829 Each probe assembly must have a leak-free Exhibit to the sorbent traps. Each sorbent trap must
10830 be mounted at the entrance of or within the probe such that the gas sampled enters the trap
10831 directly. Each probe/sorbent trap assembly must be heated to a temperature sufficient to prevent
10832 liquid condensation in the sorbent traps. Auxiliary heating is required only where the stack
10833 temperature is too low to prevent condensation. Use a calibrated thermocouple to monitor the
10834 stack temperature. A single probe capable of operating the paired sorbent traps may be used.
10835 Alternatively, individual probe/sorbent trap assemblies may be used, provided that the individual
10836 sorbent traps are co-located to ensure representative mercury monitoring and are sufficiently
10837 separated to prevent aerodynamic interference.

10838

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5.1.3 Moisture Removal Device

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10841 A robust moisture removal device or system, suitable for continuous duty (such as a Peltier
10842 cooler), must be used to remove water vapor from the gas stream prior to entering the gas flow
10843 meter.

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5.1.4 Vacuum Pump

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10847 Use a leak-tight, vacuum pump capable of operating within the candidate system's flow range.

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5.1.5 Gas Flow Meter

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10851 A gas flow meter (such as a dry gas meter, thermal mass flow meter, or other suitable
10852 measurement device) must be used to determine the total sample volume on a dry basis, in units
10853 of standard cubic meters. The meter must be sufficiently accurate to measure the total sample
10854 volume to within 2 percent and must be calibrated at selected flow rates across the range of
10855 sample flow rates at which the sorbent trap monitoring system typically operates. The gas flow
10856 meter must be equipped with any necessary auxiliary measurement devices (e.g., temperature
10857 sensors, pressure measurement devices) needed to correct the sample volume to standard
10858 conditions.

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5.1.6 Sample Flow Rate Meter and Controller

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10862 Use a flow rate indicator and controller for maintaining necessary sampling flow rates.

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5.1.7 Temperature Sensor

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10866 Same as Section 6.1.1.7 of Method 5 in appendix A-3 to 40 CFR 60, incorporated by reference in

10867 Section 225.140.

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5.1.8 Barometer

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10871 Same as Section 6.1.2 of Method 5 in appendix A-3 to 40 CFR 60, incorporated by reference in
10872 Section 225.140.

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5.1.9 Data Logger (Optional)

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10876 Device for recording associated and necessary ancillary information (e.g., temperatures,
10877 pressures, flow, time, etc.).

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5.2 Gaseous Hg⁰ Sorbent Trap Spiking System

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10881 A known mass of gaseous Hg⁰ must be spiked onto section 3 of each sorbent trap prior to
10882 sampling. Any approach capable of quantitatively delivering known masses of Hg⁰ onto sorbent
10883 traps is acceptable. Several technologies or devices are available to meet this objective. Their
10884 practicality is a function of mercury mass spike levels. For low levels, NIST-certified or NIST-
10885 traceable gas generators or tanks may be suitable, but will likely require long preparation times.
10886 A more practical, alternative system, capable of delivering almost any mass required, makes use
10887 of NIST-certified or NIST-traceable mercury salt solutions (e.g., Hg(NO₃)₂). With this system,
10888 an aliquot of known volume and concentration is added to a reaction vessel containing a
10889 reducing agent (e.g., stannous chloride); the mercury salt solution is reduced to Hg⁰ and purged
10890 onto section 3 of the sorbent trap using an impinger sparging system.

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5.3 Sample Analysis Equipment

10893

10894 Any analytical system capable of quantitatively recovering and quantifying total gaseous
10895 mercury from sorbent media is acceptable provided that the analysis can meet the performance
10896 criteria in Section 8 of this procedure. Candidate recovery techniques include leaching, digestion,
10897 and thermal desorption. Candidate analytical techniques include ultraviolet atomic fluorescence
10898 (UV AF); ultraviolet atomic absorption (UV AA), with and without gold trapping; and in-situ X-
10899 ray fluorescence (XRF) analysis.

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6.0 Reagents and Standards

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10903 Only NIST-certified or NIST-traceable calibration gas standards and reagents must be used for
10904 the tests and procedures required under this Exhibit.

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7.0 Sample Collection and Transport

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7.1 Pre-Test Procedures

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7.1.1 Selection of Sampling Site

Sampling site information should be obtained in accordance with Method 1 in appendix A-1 to 40 CFR 60, incorporated by reference in Section 225.140. Identify a monitoring location representative of source mercury emissions. Locations shown to be free of stratification through measurement traverses for gases such as SO₂ and NO_x may be one such approach. An estimation of the expected stack mercury concentration is required to establish a target sample flow rate, total gas sample volume, and the mass of Hg⁰ to be spiked onto section 3 of each sorbent trap.

7.1.2 Pre-sampling Spiking of Sorbent Traps

Based on the estimated mercury concentration in the stack, the target sample rate and the target sampling duration, calculate the expected mass loading for section 1 of each sorbent trap (for an example calculation, see Section 11.1 of this Exhibit). The pre-sampling spike to be added to section 3 of each sorbent trap must be within ± 50 percent of the expected section 1 mass loading. Spike section 3 of each sorbent trap at this level, as described in Section 5.2 of this Exhibit. For each sorbent trap, keep an official record of the mass of Hg⁰ added to section 3. This record must include, at a minimum, the ID number of the trap, the date and time of the spike, the name of the analyst performing the procedure, the mass of Hg⁰ added to section 3 of the trap (µg), and the supporting calculations. This record must be maintained in a format suitable for inspection and audit and must be made available to the regulatory agencies upon request.

7.1.3 Pre-test Leak Check

Perform a leak check with the sorbent traps in place. Draw a vacuum in each sample train. Adjust the vacuum in the sample train to mercury. Using the gas flow meter, determine leak rate. The leakage rate must not exceed 4 percent of the target sampling rate. Once the leak check passes this criterion, carefully release the vacuum in the sample train then seal the sorbent trap inlet until the probe is ready for insertion into the stack or duct.

7.1.4 Determination of Flue Gas Characteristics

Determine or measure the flue gas measurement environment characteristics (gas temperature, static pressure, gas velocity, stack moisture, etc.) in order to determine ancillary requirements such as probe heating requirements (if any), initial sample rate, proportional sampling conditions, moisture management, etc.

7.2 Sample Collection

7.2.1

Remove the plug from the end of each sorbent trap and store each plug in a clean sorbent trap storage container. Remove the stack or duct port cap and insert the probes. Secure the probes and

10953 ensure that no leakage occurs between the duct and environment.

10954

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7.2.2

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10957 Record initial data including the sorbent trap ID, start time, starting dry gas meter readings,
10958 initial temperatures, set-points, and any other appropriate information.

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7.2.3 Flow Rate Control

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10962 Set the initial sample flow rate at the target value from Section 7.1.1 of this Exhibit. Record the
10963 initial gas flow meter reading, stack temperature (if needed to convert to standard conditions),
10964 meter temperatures (if needed), etc. Then, for every operating hour during the sampling period,
10965 record the date and time, the sample flow rate, the gas flow meter reading, the stack temperature
10966 (if needed), the flow meter temperatures (if needed), temperatures of heated equipment such as
10967 the vacuum lines and the probes (if heated), and the sampling system vacuum readings. Also,
10968 record the stack gas flow rate, as measured by the certified flow monitor, and the ratio of the
10969 stack gas flow rate to the sample flow rate. Adjust the sampling flow rate to maintain
10970 proportional sampling, i.e., keep the ratio of the stack gas flow rate to sample flow rate constant,
10971 to within ± 25 percent of the reference ratio from the first hour of the data collection period (see
10972 Section 11 of this Exhibit). The sample flow rate through a sorbent trap monitoring system
10973 during any hour (or portion of an hour) in which the unit is not operating must be zero.

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7.2.4 Stack Gas Moisture Determination

10976

10977 Determine stack gas moisture using a continuous moisture monitoring system, as described in 40
10978 CFR 75.11(b), incorporated by reference in Section 225.140. Alternatively, the owner or
10979 operator may use the appropriate fuel-specific moisture default value provided in 40 CFR 75.11,
10980 incorporated by reference in Section 225.140, or a site-specific moisture default value approved
10981 by the Agency.

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7.2.5 Essential Operating Data

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10985 Obtain and record any essential operating data for the facility during the test period, e.g., the
10986 barometric pressure for correcting the sample volume measured by a dry gas meter to standard
10987 conditions. At the end of the data collection period, record the final gas flow meter reading and
10988 the final values of all other essential parameters.

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7.2.6 Post Test Leak Check

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10992 When sampling is completed, turn off the sample pump, remove the probe/sorbent trap from the
10993 port and carefully re-plug the end of each sorbent trap. Perform a leak check with the sorbent
10994 traps in place, at the maximum vacuum reached during the sampling period. Use the same
10995 general approach described in Section 7.1.3 of this Exhibit. Record the leakage rate and vacuum.

10996 The leakage rate must not exceed 4 percent of the average sampling rate for the data collection
 10997 period. Following the leak check, carefully release the vacuum in the sample train.

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7.2.7 Sample Recovery

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Recover each sampled sorbent trap by removing it from the probe, sealing both ends. Wipe any deposited material from the outside of the sorbent trap. Place the sorbent trap into an appropriate sample storage container and store/preserve in appropriate manner.

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7.2.8 Sample Preservation, Storage, and Transport

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While the performance criteria of this approach provide for verification of appropriate sample handling, it is still important that the user consider, determine, and plan for suitable sample preservation, storage, transport, and holding times for these measurements. Therefore, procedures in ASTM D6911-03 "Standard Guide for Packaging and Shipping Environmental Samples for Laboratory Analysis" (incorporated by reference under Section 225.140) must be followed for all samples.

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7.2.9 Sample Custody

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Proper procedures and documentation for sample chain of custody are critical to ensuring data integrity. The chain of custody procedures in ASTM D4840-99 (reapproved 2004) "Standard Guide for Sample Chain-of-Custody Procedures" (incorporated by reference under Section 225.140) must be followed for all samples (including field samples and blanks).

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8.0 Quality Assurance and Quality Control

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Table K-1 summarizes the QA/QC performance criteria that are used to validate the mercury emissions data from sorbent trap monitoring systems, including the relative accuracy test audit (RATA) requirement (see Section 1.4(c)(7), Section 6.5.6 of Exhibit A to this Appendix, and Section 2.3 of Exhibit B to this Appendix). Except as provided in Section 1.3(h) of this Appendix and as otherwise indicated in Table K-1, failure to achieve these performance criteria will result in invalidation of mercury emissions data.

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Table K-1. Quality Assurance/Quality Control Criteria for Sorbent Trap Monitoring Systems

<u>QA/QC test or specification</u>	<u>Acceptance criteria</u>	<u>Frequency</u>	<u>Consequences if not met</u>
<u>Pre-test leak check</u>	<u>≤4% of target sampling rate</u>	<u>Prior to sampling</u>	<u>Sampling must not commence until the leak check is passed.</u>

<u>Post-test leak check</u>	<u>≤4% of average sampling rate</u>	<u>After sampling</u>	<u>[FN**] See Note, below.</u>
<u>Ratio of stack gas flow rate to sample flow rate</u>	<u>No more than 5% of the hourly ratios or 5 hourly ratios (whichever is less restrictive) may deviate from the reference ratio by more than ± %</u>	<u>Every hour throughout data collection period</u>	<u>[FN**] See Note, below.</u>
<u>Sorbent trap section 2 break-through</u>	<u>≤5% of Section 1 Hg mass</u>	<u>Every sample</u>	<u>[FN**] See Note, below.</u>
<u>Paired sorbent trap agreement</u>	<u>≤10% Relative Deviation (RD) if the average concentration is > 1.0<<mu>>g/m³</u> <u>≤20% RD if the average concentration is ≤1.0<<mu>>g/m³. Results are also acceptable if absolute difference between concentrations from paired traps is ≤ 0.03<<mu>>g/m³</u>	<u>Every sample</u>	<u>Either invalidate the data from the paired traps or report the results from the trap with the higher Hg concentration.</u>
<u>Spike Recovery Study</u>	<u>Average recovery between 85% and 115% for each of the 3 spike concentration levels</u>	<u>Prior to analyzing field samples and prior to use of new sorbent media</u>	<u>Field samples must not be analyzed until the percent recovery criteria has been met</u>
<u>Multipoint analyzer calibration</u>	<u>Each analyzer reading within ± 10% of true value and r² ≥0.99</u>	<u>On the day of analysis, before analyzing any samples</u>	<u>Recalibrate until successful.</u>

<u>Analysis of independent calibration standard</u>	<u>Within ± 10% of true value</u>	<u>Following daily calibration, prior to analyzing field samples</u>	<u>Recalibrate and repeat independent standard analysis until successful.</u>
<u>Spike recovery from Section 3 of sorbent trap</u>	<u>75-125% of spike amount</u>	<u>Every sample</u>	<u>[FN**] See Note, below.</u>
<u>RATA</u>	<u>RA ≤20.0% or Mean difference ≤ 1.0<<mu>>g/dscm for low emitters</u>	<u>For initial certification and annually thereafter</u>	<u>Data from the system are invalidated until a RATA is passed.</u>
<u>Gas flow meter calibration</u>	<u>Calibration factor (Y) within ± 5% of average value from the most recent 3-point calibration</u>	<u>At three settings prior to initial use and at least quarterly at one setting thereafter. For mass flow meters, initial calibration with stack gas is required</u>	<u>Recalibrate the meter at three orifice settings to determine a new value of Y.</u>
<u>Temperature sensor calibration</u>	<u>Absolute temperature measured by sensor within ± 1.5% of a reference sensor</u>	<u>Prior to initial use and at least quarterly thereafter</u>	<u>Recalibrate. Sensor may not be used until specification is met.</u>
<u>Barometer calibration</u>	<u>Absolute pressure measured by instrument within ± 10 mm Hg of reading with a mercury barometer</u>	<u>Prior to initial use and at least quarterly thereafter</u>	<u>Recalibrate. Instrument may not be used until specification is met.</u>

11032
 11033 [FN**] Note: If both traps fail to meet the acceptance criteria, the data from the pair of traps are
 11034 invalidated. However, if only one of the paired traps fails to meet this particular acceptance
 11035 criterion and the other sample meets all of the applicable QA criteria, the results of the valid trap
 11036 may be used for reporting under this part, provided that the measured Hg concentration is
 11037 multiplied by a factor of 1.111. When the data from both traps are invalidated and quality-
 11038 assured data from a certified backup monitoring system, reference method, or approved
 11039 alternative monitoring system are unavailable, missing data substitution must be used. 9.0
 11040 Calibration and Standardization.
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Only NIST-certified and NIST-traceable calibration standards (i.e., calibration gases, solutions, etc.) must be used for the spiking and analytical procedures in this Exhibit.

9.2 Gas Flow Meter Calibration

9.2.1 Preliminaries

The manufacturer or supplier of the gas flow meter should perform all necessary set-up, testing, programming, etc., and should provide the end user with any necessary instructions, to ensure that the meter will give an accurate readout of dry gas volume in standard cubic meters for the particular field application.

9.2.2 Initial Calibration

Prior to its initial use, a calibration of the flow meter must be performed. The initial calibration may be done by the manufacturer, by the equipment supplier, or by the end user. If the flow meter is volumetric in nature (e.g., a dry gas meter), the manufacturer, equipment supplier, or end user may perform a direct volumetric calibration using any gas. For a mass flow meter, the manufacturer, equipment supplier, or end user may calibrate the meter using a bottled gas mixture containing $12 \pm 0.5\%$ CO₂, $7 \pm 0.5\%$ O₂, and balance N₂, or these same gases in proportions more representative of the expected stack gas composition. Mass flow meters may also be initially calibrated on-site, using actual stack gas.

9.2.2.1 Initial Calibration Procedures

Determine an average calibration factor (Y) for the gas flow meter, by calibrating it at three sample flow rate settings covering the range of sample flow rates at which the sorbent trap monitoring system typically operates. You may either follow the procedures in Section 10.3.1 of Method 5 in appendix A-3 to 40 CFR 60, incorporated by reference in Section 225.140, or the procedures in Section 16 of Method 5 in appendix A-3 to 40 CFR 60. If a dry gas meter is being calibrated, use at least five revolutions of the meter at each flow rate.

9.2.2.2 Alternative Initial Calibration Procedures

Alternatively, you may perform the initial calibration of the gas flow meter using a reference gas flow meter (RGFM). The RGFM may either be: (1) A wet test meter calibrated according to Section 10.3.1 of Method 5 in appendix A-3 to 40 CFR 60, incorporated by reference in Section 225.140; (2) a gas flow metering device calibrated at multiple flow rates using the procedures in Section 16 of Method 5 in appendix A-3 to 40 CFR 60; or (3) a NIST-traceable calibration device capable of measuring volumetric flow to an accuracy of 1 percent. To calibrate the gas flow meter using the RGFM, proceed as follows: While the sorbent trap monitoring system is

11085 sampling the actual stack gas or a compressed gas mixture that simulates the stack gas
 11086 composition (as applicable), connect the RGFM to the discharge of the system. Care should be
 11087 taken to minimize the dead volume between the sample flow meter being tested and the RGFM.
 11088 Concurrently measure dry gas volume with the RGFM and the flow meter being calibrated the
 11089 for a minimum of 10 minutes at each of three flow rates covering the typical range of operation
 11090 of the sorbent trap monitoring system. For each 10-minute (or longer) data collection period,
 11091 record the total sample volume, in units of dry standard cubic meters (dscm), measured by the
 11092 RGFM and the gas flow meter being tested.

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 11094 9.2.2.3 Initial Calibration Factor
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11096 Calculate an individual calibration factor Y_i at each tested flow rate from Section 9.2.2.1 or
 11097 9.2.2.2 of this Exhibit (as applicable), by taking the ratio of the reference sample volume to the
 11098 sample volume recorded by the gas flow meter. Average the three Y_i values, to determine Y , the
 11099 calibration factor for the flow meter. Each of the three individual values of Y_i must be within \pm
 11100 0.02 of Y . Except as otherwise provided in Sections 9.2.2.4 and 9.2.2.5 of this Exhibit, use the
 11101 average Y value from the three level calibration to adjust all subsequent gas volume
 11102 measurements made with the gas flow meter.

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 11104 9.2.2.4 Initial On-Site Calibration Check
 11105

11106 For a mass flow meter that was initially calibrated using a compressed gas mixture, an on-site
 11107 calibration check must be performed before using the flow meter to provide data for this part.
 11108 While sampling stack gas, check the calibration of the flow meter at one intermediate flow rate
 11109 typical of normal operation of the monitoring system. Follow the basic procedures in Section
 11110 9.2.2.1 or 9.2.2.2 of this Exhibit. If the on-site calibration check shows that the value of Y_i , the
 11111 calibration factor at the tested flow rate, differs by more than 5 percent from the value of Y
 11112 obtained in the initial calibration of the meter, repeat the full 3-level calibration of the meter
 11113 using stack gas to determine a new value of Y , and apply the new Y value to all subsequent gas
 11114 volume measurements made with the gas flow meter.

11115
 11116 9.2.2.5 Ongoing Quality Assurance
 11117

11118 Recalibrate the gas flow meter quarterly at one intermediate flow rate setting representative of
 11119 normal operation of the monitoring system. Follow the basic procedures in Section 9.2.2.1 or
 11120 9.2.2.2 of this Exhibit. If a quarterly recalibration shows that the value of Y_i , the calibration
 11121 factor at the tested flow rate, differs from the current value of Y by more than 5 percent, repeat
 11122 the full 3-level calibration of the meter to determine a new value of Y , and apply the new Y
 11123 value to all subsequent gas volume measurements made with the gas flow meter.

11124
 11125 9.3 Thermocouples and Other Temperature Sensors
 11126

11127 Use the procedures and criteria in Section 10.3 of Method 2 in appendix A-1 to 40 CFR 60,

11128 incorporated by reference in Section 225.140, to calibrate in-stack temperature sensors and
11129 thermocouples. Dial thermometers must be calibrated against mercury-in-glass thermometers.
11130 Calibrations must be performed prior to initial use and at least quarterly thereafter. At each
11131 calibration point, the absolute temperature measured by the temperature sensor must agree to
11132 within ± 1.5 percent of the temperature measured with the reference sensor, otherwise the sensor
11133 may not continue to be used.

11134

11135

9.4 Barometer

11136

11137 Calibrate against a mercury barometer. Calibration must be performed prior to initial use and at
11138 least quarterly thereafter. At each calibration point, the absolute pressure measured by the
11139 barometer must agree to within ± 10 mm mercury of the pressure measured by the mercury
11140 barometer, otherwise the barometer may not continue to be used.

11141

11142

9.5 Other Sensors and Gauges

11143

11144 Calibrate all other sensors and gauges according to the procedures specified by the instrument
11145 manufacturers.

11146

11147

9.6 Analytical System Calibration

11148

11149 See Section 10.1 of this Exhibit.

11150

11151

10.0 Analytical Procedures

11152

11153 The analysis of the mercury samples may be conducted using any instrument or technology
11154 capable of quantifying total mercury from the sorbent media and meeting the performance
11155 criteria in Section 8 of this Exhibit.

11156

11157

10.1 Analyzer System Calibration

11158

11159 Perform a multipoint calibration of the analyzer at three or more upscale points over the desired
11160 quantitative range (multiple calibration ranges must be calibrated, if necessary). The field
11161 samples analyzed must fall within a calibrated, quantitative range and meet the necessary
11162 performance criteria. For samples that are suitable for aliquotting, a series of dilutions may be
11163 needed to ensure that the samples fall within a calibrated range. However, for sorbent media
11164 samples that are consumed during analysis (e.g., thermal desorption techniques), extra care must
11165 be taken to ensure that the analytical system is appropriately calibrated prior to sample analysis.
11166 The calibration curve ranges should be determined based on the anticipated level of mercury
11167 mass on the sorbent media. Knowledge of estimated stack mercury concentrations and total
11168 sample volume may be required prior to analysis. The calibration curve for use with the various
11169 analytical techniques (e.g., UV AA, UV AF, and XRF) can be generated by directly introducing
11170 standard solutions into the analyzer or by spiking the standards onto the sorbent media and then

11171 introducing into the analyzer after preparing the sorbent/standard according to the particular
 11172 analytical technique. For each calibration curve, the value of the square of the linear correlation
 11173 coefficient, i.e., r^2 , must be ≥ 0.99 , and the analyzer response must be within ± 10 percent of
 11174 reference value at each upscale calibration point. Calibrations must be performed on the day of
 11175 the analysis, before analyzing any of the samples. Following calibration, an independently
 11176 prepared standard (not from same calibration stock solution) must be analyzed. The measured
 11177 value of the independently prepared standard must be within ± 10 percent of the expected value.

11178
 11179 10.2 Sample Preparation

11180
 11181 Carefully separate the three sections of each sorbent trap. Combine for analysis all materials
 11182 associated with each section, i.e., any supporting substrate that the sample gas passes through
 11183 prior to entering a media section (e.g., glass wool, polyurethane foam, etc.) must be analyzed
 11184 with that segment.

11185
 11186 10.3 Spike Recovery Study

11187
 11188 Before analyzing any field samples, the laboratory must demonstrate the ability to recover and
 11189 quantify mercury from the sorbent media by performing the following spike recovery study for
 11190 sorbent media traps spiked with elemental mercury.

11191
 11192 Using the procedures described in Sections 5.2 and 11.1 of this Exhibit, spike the third section of
 11193 nine sorbent traps with gaseous Hg^0 , i.e., three traps at each of three different mass loadings,
 11194 representing the range of masses anticipated in the field samples. This will yield a 3 x 3 sample
 11195 matrix. Prepare and analyze the third section of each spiked trap, using the techniques that will
 11196 be used to prepare and analyze the field samples. The average recovery for each spike
 11197 concentration must be between 85 and 115 percent. If multiple types of sorbent media are to be
 11198 analyzed, a separate spike recovery study is required for each sorbent material. If multiple ranges
 11199 are calibrated, a separate spike recovery study is required for each range.

11200
 11201 10.4 Field Sample Analysis

11202
 11203 Analyze the sorbent trap samples following the same procedures that were used for conducting
 11204 the spike recovery study. The three sections of each sorbent trap must be analyzed separately
 11205 (i.e., section 1, then section 2, then section 3). Quantify the total mass of mercury for each
 11206 section based on analytical system response and the calibration curve from Section 10.1 of this
 11207 Exhibit. Determine the spike recovery from sorbent trap section 3. The spike recovery must be
 11208 no less than 75 percent and no greater than 125 percent. To report the final mercury mass for
 11209 each trap, add together the mercury masses collected in trap sections 1 and 2.

11210
 11211 11.0 Calculations and Data Analysis

11212
 11213 11.1 Calculation of Pre-Sampling Spiking Level

11214
 11215 Determine sorbent trap section 3 spiking level using estimates of the stack mercury
 11216 concentration, the target sample flow rate, and the expected duration. First, calculate the
 11217 expected mercury mass that will be collected in section 1 of the trap. The pre-sampling spike
 11218 must be within ± 50 percent of this mass. Example calculation: For an estimated stack mercury
 11219 concentration of 5 µg/m³, a target sample rate of 0.30 L/min, and a sample duration of 5 days:

11220
 11221
$$(0.30 \text{ L/min}) (1440 \text{ min/day}) (5 \text{ days}) (10^{-3} \text{ m}^3/\text{liter}) (5\mu\text{g/m}^3) = 10.8 \mu\text{g}$$

11222
 11223 A pre-sampling spike of 10.8 µg ± 50 percent is, therefore, appropriate.

11224
 11225 11.2 Calculations for Flow-Proportional Sampling

11226
 11227 For the first hour of the data collection period, determine the reference ratio of the stack gas
 11228 volumetric flow rate to the sample flow rate, as follows:

11229
 11230
$$R_{ref} = \frac{KQ_{ref}}{F_{ref}} \quad \text{(Equation K-1)}$$

11231
 11232 Where:
 11233

- R_{ref} = Reference ratio of hourly stack gas flow rate to hourly sample flow rate
- Q_{ref} = Average stack gas volumetric flow rate for first hour of collection period
- F_{ref} = Average sample flow rate for first hour of the collection period, in appropriate units (e.g., liters/min, cc/min, dscm/min)
- K = Power of ten multiplier, to keep the value of R_{ref} between 1 and 100. The appropriate K value will depend on the selected units of measure for the sample flow rate.

11234
 11235 Then, for each subsequent hour of the data collection period, calculate ratio of the stack gas
 11236 flow rate to the sample flow rate using the equation K-2:

11237
 11238
$$R_h = \frac{KQ_h}{F_h} \quad \text{(Equation K-2)}$$

11239
 11240 Where:
 11241

- R_h = Ratio of hourly stack gas flow rate to hourly sample flow rate
- Q_h = Average stack gas volumetric flow rate for the hour

F_h = Average sample flow rate for the hour, in appropriate units (e.g., liters/min, cc/min, dscm/min)

K = Power of ten multiplier, to keep the value of R_h between 1 and 100. The appropriate K value will depend on the selected units of measure for the sample flow rate and the range of expected stack gas flow rates.

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Maintain the value of R_h within ± 25 percent of R_{ref} throughout the data collection period.

11.3 Calculation of Spike Recovery

Calculate the percent recovery of each section 3 spike, as follows:

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$$\%R = \frac{M_3}{M_s} \times 100 \quad \text{(Equation K-3)}$$

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11252
11253

Where:

$\%R$ = Percentage recovery of the pre-sampling spike

M_3 = Mass of mercury recovered from section 3 of the sorbent trap, (μg)

$\%R$ = Percentage recovery of the pre-sampling spike

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11255
11256

11.4 Calculation of Breakthrough

Calculate the percent breakthrough to the second section of the sorbent trap, as follows:

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Where:

11261
$$\%B = \frac{M_2}{M_1} \times 100 \quad \text{(Equation K-4)}$$

11262
11263
11264

Where:

$\%B$ = Percent breakthrough

M_2 = Mass of mercury recovered from section 2 of the sorbent trap, (μg)

M_1 = Mass of mercury recovered from section 1 of the sorbent trap, (μg)

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11266
11267

11.5 Calculation of Mercury Concentration

Calculate the mercury concentration for each sorbent trap, using the following equation:

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$$C = \frac{M^*}{V_t} \quad \text{(Equation K-5)}$$

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11272
11273

Where:

- C = Concentration of mercury for the collection period, (µgm/dscm)
- M* = Total mass of mercury recovered from sections 1 and 2 of the sorbent trap, (µg)
- V_t = Total volume of dry gas metered during the collection period, (dscm). For the purposes of this Exhibit, standard temperature and pressure are defined as 20 °C and 760 mm mercury, respectively.

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11.6 Calculation of Paired Trap Agreement

Calculate the relative deviation (RD) between the mercury concentrations measured with the paired sorbent traps:

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$$RD = \frac{|C_a - C_b|}{C_a + C_b} \times 100 \quad \text{(Equation K-6)}$$

11281
11282
11283

Where:

- RD = Relative deviation between the mercury concentrations from traps "a" and "b" (percent)
- C_a = Concentration of mercury for the collection period, for sorbent trap "a" (µgm/dscm)
- C_b = Concentration of mercury for the collection period, for sorbent trap "b" (µgm/dscm)

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11.7 Calculation of Mercury Mass Emissions

To calculate mercury mass emissions, follow the procedures in Section 4.1.2 of Exhibit C to this Appendix. Use the average of the two mercury concentrations from the paired traps in the calculations, except as provided in Section 2.2.3(h) of Exhibit B to this Appendix or in Table K-1.

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12.0 Method Performance

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These monitoring criteria and procedures have been applied to coal-fired utility boilers (including units with post-combustion emission controls), having vapor-phase mercury concentrations ranging from 0.03 µg/dscm to 100 µg/dscm.

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(Source: Added at 33 Ill. Reg. _____, effective _____)