NRDC
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NATURAL RESOURCES DEFENSE COUNCIL

May 9, 2011

VIA FEDERAL EXPRESS

Honorable Lisa P. Jackson
Administrator, U.S. EPA
Ariel Rios Building
1200 Pennsylvania Ave. NW
Washington, D.C. 20004

Dear Administrator Jackson,

Please find enclosed the Natural Resources Defense Council and Sierra Club's Petition to Object to Issuance of and Reopen a State Title V Operating Permit issued by the Michigan Department of Environmental Quality for Detroit Edison's Belle River/St. Clair Power Plant, Permit No. MI-ROP-B2796-2009.

If you have any questions, do not hesitate to contact me at (312) 651-7904.

Sincerely,

Shannon Fisk
Senior Attorney
Natural Resources Defense Council

cc: Susan Hedman, Regional Administrator, U.S. EPA Region V
Brian Carley, Michigan Department of Environmental Quality
Skiles W. Boyd, Vice President, DTE Energy

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In the Matter of: **Detroit Edison Belle River/St. Clair Power Plant Permit No. MI-ROP-B2796-2009** Issued by the Michigan Department of Environmental Quality	**PETITION TO OBJECT TO ISSUANCE OF AND REOPEN A STATE TITLE V OPERATING PERMIT** Petition No.:

PETITION OF THE NATURAL RESOURCES DEFENSE COUNCIL AND SIERRA CLUB TO OBJECT TO ISSUANCE OF AND REOPEN A STATE TITLE V OPERATING PERMIT

Pursuant to Section 505(b)(2) of the Clean Air Act, 42 U.S.C. § 7661d(b)(2), 40 C.F.R. §70.8(d), and 40 C.F.R. § 70.7(f) and (g), Natural Resources Defense Council and Sierra Club (collectively, "Citizen Groups") hereby petition the Administrator of the U.S. Environmental Protection Agency ("EPA") to object to and reopen the revised Title V Operating Permit No. MI-ROP-B2796-2009 (hereafter "Title V Permit") reissued on March 14, 2011, by the Michigan Department of Environmental Quality ("MDEQ" or "Agency"), for the Belle River/St. Clair Coal Plant ("the Plant") operated by Detroit Edison, a subsidiary of DTE Energy ("DTE").

The Administrator must object to the issuance of and reopen the revised Title V Permit due to its failure to assure compliance with applicable prevention of significant deterioration ("PSD"), nonattainment new source review ("NNSR"), and hazardous air pollutant ("HAP") requirements under the Clean Air Act ("CAA"), and due to material mistakes and inaccurate statements made in establishing the terms and conditions of the permit.

I. INTRODUCTION

The St. Clair Power Plant is a fossil fuel-fired electric utility steam generating station located in St. Clair County, Michigan, and has the potential to emit more than 100 tons per year each of sulfur dioxide ("SO2"), nitrogen oxides ("NOx"), and particulate matter ("PM"). The St. Clair Power Plant consists of six operational coal-fired units. Units 1-4 are dry-bottom wall-fired boilers which commenced operation in or around 1953 and are each connected to an approximately 160 MW turbine generator. Units 6 and

7 are tangentially-fired boilers which commenced operation in or around 1961 and 1969 and are connected to a 320 MW and a 450 MW turbine, respectively.[1]

The Belle River Power Plant is a fossil fuel-fired electric utility steam generating station located next to the St. Clair Power Plant in St. Clair County, Michigan, and has the potential to emit more than 100 tons per year each of NOx, SO2, and PM. The Belle River Power Plant consists of two operating coal-fired units. Units 1 and 2 are dry-bottom wall-fired boilers which commenced construction in 1978 and began operation in 1984 and 1985, respectively. Each unit is connected to an approximately 630 MW turbine.[2]

The plants are each fossil fuel-fired steam electric plants of more than 250 million British units per hour. Therefore, each of these plants constitutes a "major stationary source" within the meaning of 40 C.F.R. § 52.2 1(b)(l)(i)(a); and a "major emitting facility" within the meaning of Section 169(1) of the Act, 42 U.S.C. § 7479(1).[3]

II. PETITIONERS

The Natural Resources Defense Council ("NRDC") is a national, non-profit, environmental organization with more than 447,000 members nationwide, including approximately 12,875 members in Michigan. NRDC is dedicated to the protection of the environment and public health, has actively supported effective enforcement of the Clean Air Act and other environmental statutes on behalf of its members for over 30 years, and works to promote the development of energy efficiency and clean energy technologies

The Sierra Club is the nation's oldest and largest grassroots environmental organization. An incorporated, not-for-profit organization, Sierra Club has 641,000 members, including approximately 16,191 members in Michigan. Its mission is to explore, enjoy, and protect the wild places of the earth, and to educate and enlist humanity to protect and restore the quality of the natural and human environment. Sierra Club has worked diligently to protect and improve air quality in the United States, curb climate change, and promote clean energy.

III. PROCEDURAL BACKGROUND

On March 30, 2010, and January 10, 2011, the Citizen Groups submitted detailed comments regarding MDEQ's proposal to revise and reissue the Title V Permit for the Belle River/St. Clair Power Plant.[4] The objections raised in this petition were raised with

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[1] *In re DTE Energy*, Notice and Finding of Violation, EPA-5-09-MI-10, at 6, ¶ 37, (hereinafter "NOV") attached as Ex. 1.
[2] *Id.* at 6, ¶ 39.
[3] *Id.* at 7, ¶ 41.
[4] The Citizen Groups' comment letters are attached as Exs. 2 and 3.

reasonable specificity in the Citizen Groups' comments on the draft revised Title V Permit during the public comment period.

MDEQ initially issued a renewed Title V Permit to Detroit Edison on July 1, 2009. On March 1, 2010, MDEQ reopened the Title V Permit to add various requirements applicable to SO2, NOx, and Ozone NOx emissions. MDEQ submitted the proposed revised Title V Permit to EPA on January 25, 2011. EPA's 45-day review period ended on March 11, 2011, and MDEQ reported not receiving any comments from EPA.[5] This Petition to Object and Reopen is timely filed within 60 days of the conclusion of EPA's review period and failure to raise objections.

MDEQ did not address the substance of the comments the Citizen Groups submitted during the public comment period because it found the comments were not relevant to the parts of the permit for which the agency had decided to reopen the Permit.[6] MDEQ did not respond to the Citizen Groups' argument that the Title V Permit also needed to be reopened to address the New Source Review violations identified by the Citizen Groups. To the extent that the Administrator finds that the Citizen Groups' objections did not affect the parts of the Title V Permit for which MDEQ reopened the Permit, the Citizen Groups also petition the EPA to reopen the Title V Permit for cause based on the law and evidence set forth below.

IV. LEGAL STANDARDS

The federal regulations adopted pursuant to Title V of the CAA require that facilities subject to Title V permitting requirements must obtain a permit that "assures compliance by the source with all applicable requirements." 40 C.F.R. § 70.1(b). Applicable requirements include, among others, the requirement to obtain a preconstruction permit that complies with applicable preconstruction review requirements under the CAA, EPA regulations, and state implementation plans ("SIPs"). 40 C.F.R. § 70.2. Title V permit applications must disclose all applicable requirements and any violations at the facility. 42 U.S.C. § 7661b(b); 40 C.F.R. §§ 70.5(c)(4)(i),(5),(8).

If a facility is in violation of an applicable requirement at the time that it receives an operating permit, the permit must include a compliance schedule. 42 U.S.C. §§ 7661b(b)(1), 7661(3). The compliance schedule must contain "an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the source will be in noncompliance at the time of permit issuance." 40 C.F.R. § 70.5(c)(8)(iii)(C). If any statements in the application were incorrect, or if the application omits relevant facts, the applicant has an ongoing duty to supplement and correct the application. 40 C.F.R. § 70.5(b).

[5] MDEQ, March 14, 2011 Staff Report Addendum for Rule 217(2) Reopening, MI-ROP-B2796-2009a. The MDEQ Staff Reports regarding this Title V Permit are attached as Ex. 4. The Title V Permit is attached as Ex. 5.
[6] MDEQ, January 25, 2011 Staff Report Addendum for Rule 217(2) Reopening, MI-ROP-B2796-2009a

A. EPA must object to a Title V permit when a petitioner demonstrates that the permit is not in compliance with the CAA

Where a state or local permitting authority issues a Title V operating permit, EPA will object if the permit is not in compliance with any applicable requirements under C.F.R. Part 70. 40 C.F.R. § 70.8(c). If the EPA does not object, "any person may petition the Administrator within 60 days after the expiration of the Administrator's 45-day review period to make such objection." 42 U.S.C. § 7661d(b)(2); 40 C.F.R. § 70.8(d).

The Administrator "shall issue an objection . . . if the petitioner demonstrates to the Administrator that the permit is not in compliance with the requirements of [the CAA]." 42 U.S.C. § 7661d(b)(2). *See also* 40 CFR § 70.8(c)(1); *New York Public Interest Research Group (NYPIRG) v. Whitman*, 321 F.3d 316, 333 n.11 (2nd Cir. 2003). The Administrator must grant or deny a petition to object within 60 days of its filing. 42 U.S.C. § 7661d(b)(2). While the burden is on the petitioner to demonstrate to EPA that a Title V Permit is deficient, *Sierra Club v. EPA*, 557 F.3d 401, 406 (6th Cir. 2009); *Sierra Club v. Johnson*, 541 F.3d. 1257, 1266-1267 (11th Cir. 2008); *Citizens Against Ruining the Environment v. EPA*, 535 F.3d 670, 677-678 (7th Cir. 2008), once such burden has been met, EPA is required to object to the permit. *NYPIRG*, 321 F.3d at 332-34.

At least one court has, correctly, found that the EPA's issuance of a Notice of Violation to a facility is alone sufficient evidence to demonstrate that the Agency should object to the Title V Permit for such facility. *New York Public Interest Research Group v. Johnson,* 427 F.3d 172, 180 (2d Cir. 2005) (*NYPIRG II*). Other courts, however, have held that an NOV is just one "relevant factor" in determining whether a Title V Permit is not in compliance. *See, e.g., Sierra Club v. EPA*, 557 F.3d at 406-07; *Sierra Club v. Johnson*, 541 F.3d at 1267. EPA has listed the factors it considers when determining whether a petitioner has demonstrated a permit is not in compliance with the CAA in cases where EPA has issued a prior finding of violation, as including:

> (1) the kind and quality of information underlying the agency's original finding that a prior violation occurred, (2) the information the petitioner puts forward in addition to the agency's enforcement actions, (3) the types of factual and legal issues that remain in dispute, (4) the amount of time that has lapsed between the original decision and the current one, and (5) the likelihood that a pending enforcement case could resolve some of these issues.

Sierra Club v. EPA, 557 F.3d at 406-07; *see also In the Matter of CEMEX, Inc., Lyons Cement Plant*, Order in Response to Petition Number: VIII-2008-01, at 6-7 (E.P.A. Apr. 20, 2009); *In re East Kentucky Power Cooperative, Inc., Hugh L. Spurlock Generating Station*, Order in Response to Petition IV-2006-4, at 13-18 (E.P.A. Aug. 30, 2007); *and In the Matter of Georgia Power Company, Bowen Steam - Electric Generating Plant*, Final Order, at 5-9 (E.P.A. Jan. 08, 2007).

B. EPA must reopen a Title V permit when it contains material mistakes, when inaccurate statements were made in establishing its terms or conditions, or when reopening is necessary to assure compliance with applicable requirements

Federal regulations list four circumstances under which EPA is required to reopen and revise a permit:

> A permit shall be reopened and revised under any of the following circumstances:
> (i) Additional applicable requirements become applicable to a major part 70 source with a remaining permit term of 3 or more years. . . .
> (ii) Additional requirements . . . become applicable . . . under the acid rain program. . . .
> (iii) The permitting authority or EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.
> (iv) The Administrator or the permitting authority determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

40 C.F.R. 70.7(f)(1). Additionally, EPA has stated that it "will reopen a permit when an emissions limit unit has not gone through the proper PSD permitting process, and therefore lacks one or more applicable requirements of the CAA in the draft or proposed title V permit." *In re East Kentucky Power Coop,* at 19.

V. GROUNDS FOR OBJECTION AND REOPENING

A. The Title V Permit does not impose the compliance schedule needed to ensure that all applicable requirements are complied with

Major stationary sources located in both attainment areas and nonattainment areas must obtain preconstruction permits under the PSD and NNSR programs before making major modifications. *See* 42 U.S.C. 7503(a); 40 C.F.R. § 52.21(i); 40 C.F.R. Part 51, Appendix S. These permitting processes, among other things, require the facilities to undergo emissions analyses and technology reviews and to implement either the best available control technology ("BACT") to limit emissions or pollution controls to achieve the lowest achievable emissions rate ("LAER"). *Id.* Additionally, the CAA prohibits modifications of major sources of HAPs unless the permitting agency determines that maximum achievable control technology ("MACT") emission limitations will be met. 42 U.S.C. § 7412(g)(2)(A).

It is a fundamental purpose of the Title V permitting program to ensure that regulated entities comply with CAA requirements. The applicant for a Title V permit must disclose its compliance status and either certify compliance or enter into an enforceable schedule of compliance to remedy violations of the Act. 42 U.S.C. 7661b(b); 40 C.F.R. § 70.5(c)(8)-(9); Mich. Admin. Code R. 336.1213(4). In its Title V Permit proceedings, Detroit Edison presumably certified compliance with all of the requirements that apply to its facility and MDEQ apparently accepted such certification, and consequently did not incorporate any schedule of compliance or other remedial measures into the Title V Permit.

As discussed below, the evidence demonstrates that Detroit Edison undertook major modifications at the Belle River/St. Clair Power Plant without obtaining the preconstruction permits required under the CAA's PSD and NNSR programs, and without establishing MACT emission limitations. By omitting information concerning applicable requirements and falsely certifying compliance with all applicable requirements, Detroit Edison made inaccurate statements to MDEQ in its application for the Title V Permit. These false certifications and inaccurate statements concerning the applicability of PSD and NNSR requirements caused MDEQ to make a material mistake in the Title V Permit by failing to include a compliance schedule for Detroit Edison's violations. As such, the Title V Permit is not in compliance with the CAA and must be reopened. 40 C.F.R. 70.7(f)(1)(iii)-(iv).

B. EPA has found that Detroit Edison is violating PSD, NNSR, and Title V requirements at the Belle River/St. Clair Power Plant

On July 24, 2009, EPA issued an NOV to DTE for violations of the NSR requirements at a number of the company's coal-fired power plant units in Michigan, including the Belle River/St. Clair Power Plant. In the NOV, the EPA found that projects constituting major modifications had been undertaken at Belle River Units 1 and 2 and St. Clair Units 2, 3, 4, 6, and 7.[7] EPA further found that such projects led to significant net emissions increases of SO2, NOx, and/or PM.[8] Based on these findings, the NOV concludes that the Belle River and St. Clair Power Plants are "in violation of" PSD and NNSR requirements of the CAA.[9] The EPA also found that DTE has failed since August 15, 1996 to submit complete Title V permit applications with information regarding the modifications at their Belle River and St. Clair Power Plants, and the need to apply, install, and operate BACT and/or LAER for SO2, NOx, CO, PM, PM10, and/or PM2.5 at those Plants.[10] EPA further found that DTE violated Title V by failing to supplement and correct the applications as required by the CAA regulations and Michigan's SIP.[11]

As previously explained, this NOV is either sufficient on its own to demonstrate that the Title V Permit is out of compliance with the CAA, *NYPIRG II*, or, at a minimum, is relevant evidence that the Permit is out of compliance with the CAA. *Sierra Club v. EPA*, 557 F.3d at 406-07; *Sierra Club v. Johnson*, 541 F.3d at 1267. In combination with

[7] NOV at 7, 11, ¶¶42-46, 52.
[8] *Id.* at 11, ¶51.
[9] *Id.* at 11, ¶¶55-56.
[10] Id. at 12, ¶61.
[11] *Id.*

the evidence of NSR violations set forth below, there can be no reasonable dispute that the Title V Permit fails to comply with the law.

C. There is additional factual evidence that EPA was correct in finding that Detroit Edison is violating PSD, NNSR, and Title V requirements at the Belle River/St. Clair Power Plant

As EPA found in its NOV, Detroit Edison has illegally and improperly avoided implementing applicable PSD, NNSR, and Title V requirements by failing to disclose major modifications it has undertaken at the Belle River/St. Clair Power Plant. The Citizen Groups have gathered additional evidence that also demonstrates violations of these applicable legal requirements.

1. Detroit Edison has undertaken major modifications at the Belle River/St. Clair Power Plant

Federal regulations promulgated under the CAA define "major modification" as "any physical change or change in method of operation" that would result in a significant emissions increase and a significant net emissions increase of a regulated pollutant. 40 C.F.R § 52.21(b)(2)(i); 40 C.F.R. Part 51, Appendix S. The evidence shows that Detroit Edison has made significant physical changes to its Belle River/St. Clair Power Plant, and that those changes result in a significant net emissions increase.

a. Detroit Edison has replaced major components of the Belle River/St. Clair Power Plant

Detroit Edison has submitted filings with Michigan state agencies in which the company identified a number of capital expenditures for replacing major components of the Belle River and St. Clair Power Plants. One such source of information is filings with the Michigan Public Service Commission ("PSC"). A second source is a series of planned outage notification reports that Detroit Edison submitted to MDEQ just before commencing major modifications at its coal units. In these reports, Detroit Edison identified various projects that would occur during a particular outage.[12] Combined, these PSC filings and notification reports confirm that major components of the Belle River/St. Clair Power Plant were replaced over the past eight years, including the following projects:

- St. Clair Unit 2:
    - Detroit Edison's 2009 Planned Outage Notification for this unit reported replacement of the tubing on the main unit condenser and the No. 4 feedwater

[12] The reports also contended that such projects constituted merely routine maintenance and asserted that the projects would not lead to a significant emissions increase. However, as explained in this section, Section V.C.1.d and Appendix A, they actually confirm the exact opposite.

heater during a five week outage beginning on October 19, 2009.[13] In testimony to the PSC, Detroit Edison identified the condenser retubing as costing approximately $1.3 million,[14] and projected spending $4.9 million to retube the main unit condensers on St. Clair Units 1 and 2 in 2009/2010[15]

- o Detroit Edison's 2006 Planned Outage Notification for this unit reported replacement of the soot blower control panels and main steam line, rebuilding of the circulating water pump, and installation of hydro-jet water cannons as part of a ten week outage beginning on March 17, 2006.[16] In January 2007 PSC testimony, Detroit Edison reported that it had carried out a 9-week long "periodic boiler overhaul" at St. Clair Unit 2 in 2006.[17]

- St. Clair Unit 3:

  - o Detroit Edison's 2004 Planned Maintenance Outage Notification for this unit reported repair or replacement of sections of tubing boiler including tubing for the condenser due to leakage caused by corrosion and erosion, along with replacement of main steam piping around the boiler, and replacement of turbine blades.[18] In February 2005 testimony, Detroit Edison reported that it had carried out a 14 week long "major boiler overhaul" at St. Clair Unit 3 in 2004.[19] Detroit Edison has also reported that it expected to spend $1 million to retube the condenser at St. Clair Unit 3 in 2004[20]

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[13] Ltr. from Wayne A. Rugenstein, Detroit Edison, to Bryce Feighner, MDEQ, Re: 2009 Planned Outage Notification – St. Clair Power Plant (B2796), Unit 2 (Oct. 29, 2009), attached as Ex. 6 (hereinafter "St. Clair Unit 2 2009 Outage").

[14] *In re Application of the Detroit Edison Company for Authority to Increase Its Rates*, Mich. PSC Case No. U-16472, Testimony of Paul Fessler (Oct. 29, 2010), at Ex. A-9 p. 5 (hereinafter "U-16472, Fessler"), attached as Ex. 7.

[15] *In re Application of the Detroit Edison Company for Authority to Increase Its Rates*, Mich. PSC Case No. U-15768, Testimony of Paul Fessler (January 2009), at p. 27 lines 1-2 (hereinafter "U-15768, Fessler"), attached as Ex. 8.

[16] Ltr. from Wayne A. Rugenstein, Detroit Edison to Lynn Fielder, MDEQ, Re: 2006 Planned Outage Notification – St. Clair Power Plant (B2796), Unit 2 (Mar. 15, 2006), attached as Ex. 9 (hereinafter "St. Clair Unit 2 2006 Outage").

[17] *In re Application of Detroit Edison Company for Reconciliation of its Power Supply Cost Recovery Plan for the 12-Month Period Ending December 31, 2006*, Mich. PSC Case No. U-14702-R, Testimony of John C. Dau (Jan. 2007), at Ex. A-10 (JCD-2), attached as Ex. 10.

[18] Ltr. from Wayne A. Rugenstein, Detroit Edison to Lynn Fiedler, MDEQ, Re: 2004 Planned Maintenance Outage Notification – St. Clair Power Plant (B2796), Unit 3 (Feb. 9, 2004), attached as Ex.11 (hereinafter, "St. Clair Unit 3 2004 Outage").

[19] *In re Application of Detroit Edison Company for Reconciliation of its Power Supply Cost Recovery Plan for the 12-Month Period Ending December 31, 2004*, Mich. PSC Case No. U-13808-R, Testimony of John C. Dau (Feb. 2005), at Ex. A-9 (JCD-2), attached as Ex. 12

[20] *In re Application of Detroit Edison Company to Increase Rates*, Mich. PSC Case No. U-13808, Testimony of Nazoor A. Baig, Detroit Edison's Director of Fossil Generation (June 2003) (hereinafter "U-13808, Baig"), at p. 34 line 14, attached as Ex.13.

- St. Clair Unit 6:

    - Detroit Edison's 2009 Periodic Outage Notification for this unit reported repair or replacement of superheater pendants and platens, upgrade of 64 burners and nozzles, retubing of the condenser, and replacement of star feeders during a ten week outage beginning on or about February 20, 2009.[21] A company PSC filing also reports that in 2009 Detroit Edison spent $3.8 million to replace superheater outlet pendants, $2.2 million to replace superheater outlet platens, $3.7 million for condenser retubing, and $2.5 million to replace the coal mill feeder on St. Clair Unit 6.[22]
    - Detroit Edison's 2007 Planned Outage Notification for this unit reported replacement of tubes in the condenser air removal section during a five week outage beginning on or about April 1, 2007.[23]
    - Detroit Edison's 2003 Planned Maintenance Outage for this unit reported replacement of economizer inlet tubes, superheater inlet and outlet pendant tubes, superheater crossover tubes, and some other boiler tubes due to tube leakage, along with replacement of turbine blades and boiler pumps.[24]
    - In a 2003 PSC filing, DTE reported that a $7.9 million replacement of water wall tubes at St. Clair Unit 6 occurred between 1994 and 2002[25]

- St. Clair Unit 7:

    - Detroit Edison's 2010 Planned Outage Notification for this unit reported replacement of the #4, #5, and #6 feedwater heaters, boiler water wall tubing, burner assemblies, and economizer expansion joints as part of an eight week outage beginning September 18, 2010.[26] According to Detroit Edison's PSC filings, the company expected to spent $6 million for waterwall tube replacements,[27] $2.6 million for multiple feedwater heater replacements,[28] and $4.1 million for other combustion improvement projects on St. Clair Unit 7

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[21] Ltr. from Wayne A. Rugenstein, Detroit Edison to William Presson, MDEQ, Re: 2009 Periodic Outage Notification – St. Clair Power Plant (B27 96), Unit 6 (Feb. 20, 2009) (Corrected Mar. 2, 2009), attached as Ex. 14 (hereinafter "St. Clair Unit 6 2009 Outage Letter").
[22] U-16472, Fessler at Ex. A-9 p. 5.
[23] Ltr. from Wayne A. Rugenstein, Detroit Edison, to Lynn Fiedler, MDEQ, Re: 2007 Planned Outage Notification – St. Clair Power Plant (B2796) Unit 6 (Mar. 20, 2007), attached as Ex. 15 (hereinafter, "St. Clair Unit 6 2007 Outage").
[24] Ltr. from Skiles W. Boyd, Detroit Edison, to G. Vinson Hellwig, MDEQ, Re: 2003 Planned Maintenance Outage – St. Clair Power Plant (B2796), Unit 6 (Oct. 1, 2003), attached as Ex. 16.
[25] U-13808, Baig at p. 23 line 4.
[26] Ltr. from Barry Marietta, Detroit Edison, to William Presson, MDEQ, Re: 2010 Planned Outage Notification – St. Clair Power Plant (B2796) Unit 7 (Aug. 31, 2010), attached as Ex.17 (hereinafter "St. Clair Unit 7 2010 Outage").
[27] U-15768, Fessler at p. 26 lines 13-14.
[28] U-15768, Fessler at p. 27 lines 3-4.

during the 2010 outage.[29] A more recent PSC filing stated that the company spent approximately $10.6 million on these modifications.[30]

- o Detroit Edison's 2007 Planned Outage Notification for this unit reported retubing of the main unit condenser, the boiler feed pump turbine condenser, and sections of waterwall tubing; replacement of the #3 feedwater heater, the #5 and #7 High Pressure feedwater heaters, and the main condenser vacuum pump; and rebuilding of the center circulating water pump and the gearboxes on the A and B coal mills during a ten week outage beginning on or about January 5, 2007.[31] In a PSC filing, Detroit Edison estimated that these modifications cost $15 million.[32]

- Belle River Unit 1:

  - o Detroit Edison's 2008 Periodic Outage Notification for this unit reported repair or replacement of water wall boiler tube sections, economizer expansion joints, draft system duct expansion joints, and sections of the bottom ash system, along with replacements of some turbine blades during an eleven week outage beginning on or about September 12, 2008.[33] In testimony filed with the PSC, Detroit Edison estimated that it planned to spend $8.4 million to replace waterwall tube sections on Belle River Unit 1 in 2008/2009[34]
  - o Detroit Edison has also reported that it has under development for the 2010 to 2012 timeframe a $15 million project to replace superheater and waterwall sections on Belle River Unit 1.[35]

- Belle River Unit 2:

  - o Detroit Edison's 2010 Planned Outage Notification for this unit reported replacement or repair of water wall sections of tubing, expansion joints, bottom ash sump pumps, and high pressure turbine valves, along with installation of a new boiler tubing hydrojet cleaning system and a combustion

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[29] U-15768, Fessler at p. 27 lines 5-6.
[30] U-16472, Fessler at Ex. A-9 p. 6.
[31] Ltr. from Wayne A. Rugenstein, Detroit Edison to Lynn Fiedler, MDEQ, Re: 2007 Planned Outage Notification – St. Clair Power Plant (B2796) Unit 7 (Dec. 20, 2006), attached as Ex. 18 (hereinafter "St. Clair Unit 7 2007 Outage").
[32] *In re Application of the Detroit Edison Company for Authority to Increase Its Rates*, Mich. PSC Case No. U-15244, Testimony of David B. Harwood, at p. 26 lines 14-20 (April 2007) (hereinafter, "U-15244, Harwood"), attached as Ex. 19.
[33] Ltr. from Wayne A. Rugenstein, Detroit Edison to William Presson, MDEQ, Re: 2008 Periodic Outage Notification – Belle River Power Plant (B2796), Unit 1 (Sept. 11, 2008), attached as Ex. 20 (hereinafter "Belle River Unit 1 2008 Outage").
[34] U-15768, Fessler at p. 22 lines 15-18.
[35] U-15244, Harwood at p. 35 lines 20-21.

monitoring grid in the boiler during a five week outage beginning on or about February 6, 2010.[36]

- Detroit Edison's 2007 Planned Outage Notification for this unit reported replacement of sections of tubing in superheat, bullnose, and waterwall areas of the boiler during a ten week outage beginning on or about September 28, 2007.[37] In a PSC filing, Detroit Edison estimated that the waterwall tube section replacements would cost $4.4 million[38] and reported that it had spent $5.4 million to replace the secondary superheater pendants on Belle River Unit 2 in 2007/2008.[39] A separate PSC filing projected that Detroit Edison would spend $6 million for installation of a new generator exciter and replacement of the center half of the high temperature superheater at Belle River Unit 2 during the Fall 2007 periodic outage.[40]

b. Detroit Edison's capital expenditures at the Belle River/St. Clair Power Plant were undertaken to extend the life, increase the availability, and reduce forced outages of the Plant, and in fact did so

Each of the projects summarized above was carried out or planned pursuant to one of Detroit Edison's two primary programs for making capital expenditures on its coal-fired power plants. First is the company's "Plant Improvement Project" capital budget, which is "designed to prioritize projects in order to achieve the best combination of reliability and generation economics."[41] The second is the "Boiler Tube Failure Reduction" team, which was created in 2003 in order to "identify the most critical needs for investments in our boilers."[42]

These capital expenditures are quite similar to the projects that a leading industry engineering firm, Babcock & Wilcox, has described as being necessary to extend the life of an existing coal plant well beyond the expected useful life.[43] Detroit Edison's PSC filings make clear that life extension is exactly what the company was aiming for. In particular, Detroit Edison explained that these capital programs are designed to address the fact that the company's "fossil steam fleet's average age of over 30 years is at, or

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[36] Ltr. from Wayne A. Rugenstein, Detroit Edison to William Presson, MDEQ, Re: 2010 Periodic Outage Notification – Belle River Power Plant (B2796), Unit 2 (Feb. 6, 2010), attached as Ex. 21 (hereinafter "Belle River Unit 2 2010 Outage").

[37] Ltr. from Wayne A. Rugenstein, Detroit Edison to William Presson, MDEQ, Re: 2007 Planned Outage Notification – Belle River Power Plant (B2796), Unit 2 (Sept. 19, 2007), attached as Ex.22 (hereinafter "Belle River Unit 2 2007 Outage").

[38] U-15768, Fessler at p. 19 line 18.

[39] U-15678, Fessler at p. 19 line 16-17.

[40] U-15244, Harwood at p. 27 line 13 to p. 28 line 4.

[41] U-13808, Baig at p. 20 lines 17-19.

[42] *In re the Commission's Own Motion Ordering the Detroit Edison Company to Show Cause Why Its Retail Sales for the Sale and Distribution of Electric Energy Should Not Be Decreased*, PSC Case No. U-14838, Testimony of Guy N. Harris, at p. 14 line 23 to p.15 line 5 (June 1, 2006) (hereinafter "U-14838, Harris"), attached as Ex. 23.

[43] Babcock & Wilcox, Steam (40th ed.), at Ch. 46, attached as Ex. 24.

nearing, the design life of major components.[44] As the company stated, "many systems which are experiencing increasing reliability problems that result in more frequent and longer duration outages, as well as frequent derated operation, must be proactively replaced."[45] Detroit Edison has further noted that it "has experienced, and continues to experience, end of design life for many major components that require ongoing O&M and capital investments."[46] The company's PSC filings similarly explain that it Boiler Tube Failure Reduction program is part of "recognizing that most of our equipment is reaching end of design life,"[47] and that the various capital expenditures identified above were "necessary to maintain system reliability and to replace aging equipment, which had become unreliable or failed in service."[48]

There are a number of examples of specific availability and outage problems caused by the aging equipment that Detroit Edison replaced. For example, St. Clair Unit 7 had 21 forced outages due to 54 boiler tube failures between 1995 and April 2000.[49] The $15 million to install waterwall tubes, re-tube the main unit and boiler feed pump condensers, and replace feedwater heaters at St. Clair Unit 7 in 2007 was carried out because the Boiler Tube Task Force identified those components "as being at end of life" and "to prevent increasing failure rates from adversely affecting plant water chemistry and boiler tube integrity."[50] Similarly, Detroit Edison replaced superheater tubes at Belle River Unit 2 because they had "reached end of life due to creep rupture . . . and experienced five superheater tube leak outages due to creep rupture and long term overheating since 2001."[51] Also, an application for a patent for a method and apparatus for controlling final feedwater temperatures in power plant boilers included the following discussion of feedwater degradation at St. Clair Units 1, 4, and 6:

> To teach an actual application of the present invention, consider the case found at the St. Clair Station, Units 1, 4 and 6 . . . . Units 1 and 4 were originally designed to produce 170 MWe each, Unit 6 was originally designed to produce 336 MWe. All are coal-fired. At full load, Unit 1's final feedwater temperature was found degraded by 12.9Δ° F. (7.2Δ° C.), Unit 4's final feedwater temperature was found degraded by 14.4Δ° F. (8.0Δ° C.), and Unit 6's final feedwater temperature was found degraded by 9.2Δ° F. (5.1Δ° C.). Units 1 and 4 were unable to produce design power given limitations to feedwater and combustion air flows, aggravated by degradation in feedwater temperatures; degradation in Unit 1 was 25 ΔMWe (worth $8 million/year in power sales at $40/MWe-hour), degradation in Unit 4 was 18 ΔMWe (worth $5.8 million/year in power

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[44] U-13808, Baig at p. 15 lines 6-8; U-14838, Harris at p. 8 lines 11-12.
[45] U-13808, Baig at p.27 lines 1-4.
[46] U-15244, Harwood at p. 11 lines 16-20.
[47] U-14838, Harris at p. 14 line 23 to p.15 line 5.
[48] U-13808, Baig at p. 24 lines 6-7.
[49] EPRI Boiler Reliability Optimization Program – Case Studies From 1998-2001 (Dec. 2001), at 3-12, attached as Ex. 25.
[50] U-15244, Harwood at p. 26 lines 14-20.
[51] U-15244, Harwood at p. 27 line 13 to p. 28 line 4.

sales). At the time of testing Unit 6 was capable of producing design power.[52]

Detroit Edison's PSC filings also provide strong evidence that the capital expenditures identified above were successful in increasing the availability and reducing the forced outages at the Belle River/St. Clair Power Plant. For example, Detroit Edison reported a 12MW capacity increase for Belle River Unit 1 due to reductions in internal load and boiler modifications carried out in 2007-2008.[53] Similarly, the company reported that its Boiler Tube Failure Reduction team's efforts have led to boiler waterwall and steam tubing replacements that "have and will continue to result in reduced forced outage frequencies across the fleet. The combination of reduced outage duration and frequency are expected to save $9 million in 2007 and as much as $26 million annually in the 2008-2012 time period,"[54] presumably due to an increase in the company's ability to run the modified plants. Also, after superheater tubes were replaced in Belle River Unit 1 in 2003, Detroit Edison had experienced no superheater tube leaks in that unit as of 2007, even while similar tubes in Belle River Unit 2 had experienced five leaks since 2001.[55]

In fact, overall availability of the Belle River/St. Clair Power Plant increased significantly during the time when these capital expenditures were being made. For example, in 2002 the Belle River Power Plant had an availability of 77.45% and was projected to increase to an average of 80.7% in 2005 through 2008.[56] In 2006, the availability for Belle River was 82.0%, and was projected to be 87.7% in 2009 and 2010, and 84.7% in 2011 and 2012.[57] In 2002 the St. Clair Power Plant had an availability of 80.58% and was projected to increase to an average of 85.52% in 2005 through 2008.[58] In 2006, the St. Clair Power Plant had an availability of 81.7%, and was projected to increase to 84.6% in 2010, 84.1% in 2011, and 83.1% in 2012.[59]

Similarly, Detroit Edison projected and experienced reductions in the Random Outage Rate ("ROR"), which is the percentage of generation lost through derated operation and non-periodic outages at its coal-fired facilities due to its capital expenditures. The ROR for Detroit Edison's coal-fired fleet was projected to decline from an average of 11.85% in 2000 through 2002 and 12.48% in 2003 to an average of 10.29% from 2004 through 2008 and 9.45% in 2008.[60] This predicted improvement in ROR was "a direct result of the capital improvements, planned maintenance activities, and increased predictive and preventive maintenance programs" at Detroit Edison's coal-

[52] U.S. Patent 7040095, Method and Apparatus for Controlling the Final Feedwater Temperature of a Regenerative Rankine Cycle, Application No. 11204898, filed 8/16/2005, attached as Ex. 26.
[53] U-15244, Harwood at p. 10 lines 5-7.
[54] U-15244, Harwood at p. 52 lines 12-20.
[55] U-15244, Harwood at p. 27 line 13 to p. 28 line 4.
[56] U-13808, Baig at Ex. A-16, Schedule F6-1.
[57] U-15244, Harwood at Ex. A-16, Schedule F6-1.
[58] *Id.*
[59] U-15244, Harwood at Ex. A-16, Schedule F6-1.
[60] U-13808, Baig at p. 50 lines 12-16.

fired power plants.[61] By 2007, the random outage factor was 7.75%,[62] and between July 2007 and June 2008, the figure was 8.1%.[63]

c. Detroit Edison's modifications at the Belle River/St. Clair Power Plant are not Routine Maintenance, Repair, or Replacement

The CAA defines "modifications" subject to the PSD and NNSR programs as including <u>any</u> physical or operational change without limitation. 42 U.S.C. §§ 7411(a)(4) (emphasis added). Because this definition, read literally, applies the PSD and NNSR program to even the replacement of a single screw during day-to-day maintenance, the EPA has adopted regulations based on the *de minimis* legal doctrine that provide that "routine maintenance, repair, and replacement" ("RMRR") activities are exempt from the definition of modification. 40 C.F.R. §§ 51.165(a)(1)(v)(C), 51.166(b)(2)(iii), 52.21(b)(2)(iii)(a); Mich. Admin. Code R. 336.2801(aa)(iii)(A); *see also* 67 Fed. Reg. 80,290, 80,292 (Dec. 31, 2002); 57 Fed. Reg. 32313, 32316-19 (July 21, 1992); *Wis. Elec. Power Co. v. Reilly,* 893 F.2d 901, 905 (7th Cir. 1990) (hereinafter "*WEPCO*").

The U.S. Court of Appeals for the Seventh Circuit has summarized and approved the four-part test EPA uses to assess whether a project falls within the narrow RMRR exemption: (1) the nature and extent of a change; (2) the purpose for the change; (3) the frequency of the change; and (4) the cost of the change. *WEPCO*, 893 F.2d at 909-11; *see also* 67 Fed. Reg. 80,290, 80,292-93 (Dec. 31, 2002) (describing the routine maintenance exemption as "a case-by-case determination by weighing the nature, extent, purpose, frequency, and cost of the work as well as other factors to arrive at a common sense finding."). District Courts have generally applied this four-factor *WEPCO* test. *United States v. Cinergy Corp.*, 495 F. Supp. 2d 909, 933-948 (S.D.Ind. 2007); *United States v. Southern Indiana Gas & Electric Co.,* 245 F. Supp. 2d 994, 1008 (S.D.Ind. 2003); *United States v. Southern Indiana Gas & Electric Co.,* 2003 WL 446280, *2 (S.D.Ind. Feb. 18, 2003); *United States v. Southern Indiana Gas & Electric Co.*, 258 F. Supp. 2d 884, 886 (S.D. Ind. 2003); *see also Ohio Edison*, 276 F. Supp. 2d at 834.

EPA's long-standing interpretation of the RMRR exemption, "is to construe "physical change" very broadly, to cover virtually any significant alteration to an existing plant and to interpret the exclusion related to routine maintenance, repair and replacement narrowly."[64] This interpretation is fully consistent with the intent of the NSR provisions, which is to ensure that existing air pollution sources that were grandfathered under the Clean Air Act are not granted an endless exemption from the Act's requirements. *Cf. WEPCO*, 893 F.2d at 909 (warning that RMRR cannot be interpreted to "open vistas of indefinite immunity from the provisions of ... PSD"); *Ohio Edison*, 276 F. Supp. 2d at

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[61] U-13808, Baig at p. 50 lines 17-19.

[62] *In re Application of Detroit Edison Company for Reconciliation of Its Power Supply Cost Recovery Plan for the 12-Month Period Ending December 31*, 2007, Mich. PSC Case No. U-15002-R, Testimony of Angela P. Wojtowicz (Jan. 2007), at p. 8 lines 18-20, attached as Ex. 27.

[63] U-15768, Fessler at p. 12 lines 4-5.

[64] Letter from Doug Cole, EPA, to Alan Newman, Washington Dept. of Ecology (November 5, 2001), *available at* http://www.epa.gov/region7/programs/artd/air/NNSR/NNSRmemos/20011105.pdf.

855; *Sierra Club v. Morgan*, Case No. 07-c-251-s, Order at 25 (W.D.Wis. Nov. 7, 2007); *In re TVA*, 9 E.A.D. at 410-11 (rejecting an interpretation of RMRR that would "constitute 'perpetual immunity' for existing plants").

As the D.C. Circuit has held, the RMRR exemption is only lawful (if at all[65]), based on a *de minimis* theory of administrative necessity. *Alabama Power Co. v. Costle*, 636 F.2d 323, 360-61, 400 (D.C.Cir. 1979); *see also New York v. EPA*, 443 F.3d 880, 883-84, 888 (D.C. Cir. 2006) (holding that the only possible basis for a RMRR is a *de minimis* theory); *In re Tennessee Valley Authority*, 9 E.A.D. at 392-93 (citing *O'Neil v. Barrow County Bd. of Comm'rs*, 980 F.2d 674 (11th Cir. 1993); *North Haven Bd. of Educ. v. Bell*, 456 U.S. 512 (1982)); *United States v. S. Indiana Gas and Elec. Co.*, 245 F.Supp. 2d 994, 1019 (S.D. Ind. 2003) (hereinafter "*SIGECO*") (quoting an EPA determination for Wisconsin Electric's Port Washington plant that the exemptions from the definition of "modification"—including routine maintenance—are "very narrow.").

Consistent with this narrow interpretation, courts have identified three hallmarks of the RMRR exemption:

> First, the exemption applies to a *narrow range of activities*, in keeping with the EPA's limited authority to exempt activities from the [CAA]. Second, the exemption applies only to activities that are *routine for a generating unit*. The exemption does not turn on whether the activity is prevalent within the industry as a whole. Third, *no activity is categorically exempt*. EPA examines each activity on a case-by-case basis, looking at the nature and extent, purpose, frequency, and cost of the activity.

SIGECO, 245 F.Supp. 2d at 1008 (emphasis added, original emphasis omitted).

In short, routine maintenance "occurs regularly, involves no permanent improvements, is typically limited in expense, is usually performed in large plants by in-house employees, and is treated for accounting purposes as an expense." *Ohio Edison*, 276 F. Supp. 2d at 834 (citing *WEPCO*, 893 F.2d 901). Non-routine and, therefore non-exempt, projects include "capital improvements which generally involve more expense, are large in scope, often involve outside contractors, involve an increase of value to the unit, are usually not undertaken with regular frequency, and are treated for accounting purposes as capital expenditures on the balance sheet." *Id.*

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[65] The D.C. Circuit has implied in *dicta* that the RMRR exclusion may be an unlawful "application of the *de minimis* exception, given the limits on the scope of the *de minimis* doctrine." *New York*, 443 F.3d at 888, *citing Shays v. FEC*, 414 F.3d 76, 113-14. In *Shays*, the D.C. Circuit held that "there are limits" to agencies' ability to create *de minimis* exceptions to statutory schemes, including: (1) that the "*de minimis* exemption power does not extend to 'extraordinarily rigid' statutes"; and (2) that it "does not extend to 'a situation where the regulatory function does provide benefits, in the sense of furthering regulatory objectives, but the agency concludes that the acknowledged benefits are exceeded by the costs'." 414 F.3d at 114.

i. EPA determinations have found projects similar to those at the Belle River/St. Clair Power Plant are not RMRR

EPA has made a number of applicability determinations for PSD for modifications similar to those at the Belle River/St. Clair Power Plant. These determinations constitute guidance from EPA about the very narrow scope of the RMRR exclusion.

For boiler tube replacements, EPA has noted that the "nature and extent" factor for RMRR distinguishes between routine projects that replace one or two worn tubes, and non-routine projects that replace all of the tubes in an entire boiler section. In a January 29, 2003 determination EPA determined that that a proposal by P.H. Glatfelter to replace steam tubes was not routine maintenance.[66] As to the "nature and extent" factor, EPA distinguished between a project to replace numerous tubes (1060 in that case) with "the more typical maintenance activities that are performed annually in that it involves a complete replacement of the tubes in a major component of the boiler, as opposed to replacement of just a few worn or damaged tubes on an as-needed basis."[67] Moreover, EPA noted that the project was expected "to require 5 weeks to complete," which EPA suggests is more than routine maintenance procedures require.[68]

In guidance to the Washington Department of Ecology, EPA addressed the applicability of RMRR to two projects: (1) to replace a portion (the firebox) of a recovery furnace at a paper mill and (2) a tube replacement within the fire box at another paper mill recovery furnace.[69] Regarding the first project, EPA agreed with the state's conclusion that the project was not RMRR. Regarding the second project, a replacement of the economizer and generating bank, EPA concluded that the "nature and extent" of the project did not support an RMRR finding because entire components, rather than a few individual tubes were replaced:

> All economizer and generator bank tubes have been replaced. Although the replacement tubes represent less than half of total boiler tube area, they also represent complete replacement of all the tubes in two major components of the boiler. It is our understanding that such a wholesale change to a major component of RF 2 does not occur annually, or on any regular basis. This is not a matter of merely replacing only a few worn or damaged tubes on an as-needed basis. The fact that it took three weeks to accomplish the on-site work is significant because it extends beyond the mill's typical two week outage for annual maintenance. These facts

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[66] Ltr from Robert B. Miller, EPA to Steven Dunn, Wisconsin DNR (Jan. 29, 2003) ("Glatfelter Decision"), *available at* http://www.epa.gov/region7/programs/artd/air/NNSR/NNSRmemos/20030129.pdf.

[67] *Id.*

[68] *Id.*

[69] Ltr from Doug Cole, EPA to Alan Newman, Wash. Dept. of Ecology (Nov. 5, 2001) (Boise Cascade Decision), *available at* http://www.epa.gov/region7/programs/artd/air/NNSR/NNSRmemos/20011105.pdf

> indicate that the complete replacement of all the tubes in major components is not routine.[70]

In a determination addressed to the Tennessee Department of Environment and Conservation, EPA concluded that a project to replace all of the tubes in a boiler's generating bank and partially replacing tubes on an economizer were not RMRR.[71] In the Packaging Corp. Decision, EPA found that replacement of all of the tubes in a boiler component is not Routine Maintenance:

> This replacement differs from the more typical maintenance activities that are performed annually in that it involves complete replacement of all the tubes in a major component of the boiler, as opposed to replacement of just a few worn or damaged tubes on an as-needed basis. In addition, the expected duration of the tube replacement project is approximately 20 days. Although the project is proposed for a period of scheduled mill outage, the amount of time required for the project is significant.[72]

Whether a project is a "life extension" is important to the "purpose" factor, in that life extension projects are not routine maintenance, but other facts can weigh against a routine maintenance finding under the "purpose" factor. For example, in the Glatfelter Decision, EPA did not conclude that the project was a life extension. Instead, the agency noted that the project might be a life extension, but also noted that "the proposed project can be viewed as a significant repair of a major boiler component."[73] Additionally, when EPA looks at the "purpose" of a project, it looks at whether the component being replaced, as a whole, "was near, or had exceeded, its useful life."[74]Therefore, where a component part of a boiler (i.e., economizer, generating bank, or superheater) is worn and the component's overall condition counsels for replacement, the project is not RMRR.[75]

It is clear from EPA's application of the "frequency" factor that the agency looks to the frequency at which a project occurs at the individual unit at issue.[76] In each of these

[70] *Id.* at 3.
[71] Letter from Gregg M. Worley, EPA, to Barry R. Stephens, Tenn. Dept. of Envt. and Conservation, at 4 (Sept. 14, 2001) (Packaging Corp. Decision), *available at* http://www.epa.gov/region7/programs/artd/air/NNSR/NNSRmemos/pca2001.pdf.
[72] *Id.* at 3.
[73] Glatfelter Decision at 2.
[74] Boise Cascade Decision at 4.
[75] *Id.*; *see also* Packaging Corp. Decision at 3 (noting that the project would "substantially increase the life of *the tubes*" and not only whether the project would extend the life of the unit (emphasis added)).
[76] Glatfelter Decision at 2 (finding that a tube replacement project is not RMRR because, *inter alia*, "this would be the first time in the 35 year *life of the boiler* where all the tubes would be replaced. Moreover, the infrequency of such replacement *at this boiler* supports our understanding that complete boiler tube replacements are not performed on a frequent basis.") (emphasis added); Letter from Winston A. Smith, EPA, to James P. Johnson, Georgia Envtl. Protection Dept. (January 28, 2002) (finding that frequency did not support a finding of RMRR "[b]ased on the information presented to us, the previous owner of the mill never performed the same changes *at the No. 3 Recovery Boiler* during its entire 17-year operating history..") (emphasis added); Letter from Doug Cole, EPA, to Alan Newman, Washington Dept. of Ecology at 4 (Nov. 5, 2001) ("EPA is not aware of [Recovery Furnace Number] 2 undergoing such an extensive boiler tube replacement project since it started up as a recovery furnace in 1980, more than

determinations, EPA looked at how frequently a project has occurred during the life of the source at issue.

When analyzing boiler tube projects, EPA focuses on the cost of a project compared to the cost of a typical tube replacement project. For example, in the Glatfelter Decision, the agency compared the project cost of $450,000 to "a typical tube repair [which] cost would be approximately $50,000" to conclude that "[t]he project cost is significantly higher than the expected maintenance general replacement costs."[77] Additionally, EPA compares the cost to the typical maintenance costs for a boiler.[78] EPA has not relied on the fact that a physical change costs only a fraction of the cost of a new boiler.[79]

ii. Courts have held that projects similar to those at the Belle River/St. Clair Power Plant are not RMRR.

Court decisions regarding RMRR demonstrate that certain types of projects categorically cannot be considered routine maintenance. These categorically non-routine projects include:

- Projects approved by management, planned by a central office, using outside contractors, and involving replacements of entire components. *Ohio Edison*, 276 F. Supp. 2d at 834, 859; *In re TVA*, 9 E.A.D. at 481, 484-85, 490-91, 493-94.
- Projects which include modifying or replacing numerous parts and redesigned, custom, or "upgraded" parts. See *Cinergy*, 495 F. Supp. 2d at 934.
- Projects that have a purpose of improving operations by extending the operational life of the unit or resulting in fewer needed shutdowns to perform repairs are not routine maintenance. *WEPCO*, 893 F.2d at 911-12 (holding that a project that rehabilitates aging units as an alternative to retiring them is not routine); *Cinergy*, 495 F. Supp. 2d at 935 (finding a project non-routine based, in part, on the fact that the purpose was to "'improve[] operating efficiency' with less [sic] potential outages."); *Ohio Edison*, 276 F. Supp. 2d at 858, 860 (finding non-routine a project that "reduc[ed] forced outages and improv[ed] availability and reliability of the unit(s)").

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twenty years ago"); Letter from Gregg M. Worley, EPA, to Barry R. Stephens, Tenn. Dept. of Envt. and Conservation at 4 (September 14, 2001) ("Therefore, during the entire 40-year operating history of R-1, a generating bank tube replacement project of the magnitude now proposed has occurred only once."); Letter from R. Douglas Neeley, USEPA, to Jimmy Johnson, Georgia Envtl. Protection Dept. (September 13, 2000) (finding that a project at a boiler was not RMRR because, inter alia, such a project had never been done "throughout the 48-year history *of the furnace*").

[77] Glatfelter Decision at 2.

[78] Packaging Corp. Decision at 4 (comparing the $924,000 project cost to the "normal [boiler] annual maintenance costs that have ranged from $629,968 to $979,969").

[79] *Id.* (taking note that the project costs "less than one percent of the cost of a new comparable... boiler" but finding the cost nevertheless to weigh against RMRR).

- Projects paid for with funds other than a plant's operating and maintenance budget, or which are treated as capital expenses on balance sheets are not routine. *Cinergy*, 495 F. Supp. 2d at 933; *Ohio Edison*, 276 F. Supp. 2d at 834, 859, 862.

The federal court in *Ohio Edison* found projects quite similar to those undertaken by Detroit Edison to constitute major modifications that triggered NSR requirements. These projects included:

- $6.1 million replacement of three banks of horizontal reheater tubes, furnace ash hopper boiler tubes, and secondary superheater outlet headers at Unit 1;
- $5.8 million replacement of three banks of horizontal reheater tubes, furnace ash hopper boiler tubes, and secondary superheater outlet headers at Unit 2;
- $7.3 million replacement of three banks of horizontal reheater tubes, furnace ash hopper boiler tubes, front wall south cell tubes, furnace south sidewall tubes, and secondary superheater outlet headers at Unit 3;
- $3.7 million replacement of furnace ash hopper tubes, front waterwall tubes, and superheater control condenser tubes at Unit 4;
- $12.0 million replacement of the vertical tube furnace with a spiral tube furnace at Unit 5;
- $4.8 million replacement of economizer tubes, secondary superheater outlet pendant tubes, and reheater outlet pendant tubes at Unit 5;
- $6.3 million replacement of horizontal reheater and economizer tubes at Unit 6;
- $20.7 million replacement of burners, waterwall tubes, reheater riser and pendant tubes, mix area wall panels, and coal pipes at Unit 6;
- $16.5 million replacement of pulverizers at Unit 6;
- $29 million replacement of economizer tubes, horizontal reheater and reheater riser tubes, front ash hopper tubes, low pressure turbine rotors, burners, coal pipes, pulverizers, and combustion controls at Unit 7;
- $446,000 replacement of waterwall tube panels at Unit 7.

Ohio Edison, 276 F. Supp. 2d at 840-849.

The above decisions of EPA and federal courts make clear that the capital expenditures made by Detroit Edison at the Belle River/St. Clair Power Plant and described above constitute modifications, not RMRR. As shown, each of the projects discussed were multi-million dollar endeavors that replaced integral components of the Plant and would be expected to occur only once or a few times over the expected life of the Plant. The projects were designed to address the fact that the components had reached the end of their useful lives and were leading to increasing numbers of outages and derates. As such, Detroit Edison cannot validly demonstrate that such projects constituted mere RMRR.

d. The modifications at the Belle River/St. Clair Power Plant led to emissions increases that trigger the PSD and NNSR requirements of the CAA.

The CAA provides two alternative routes for determining whether the modifications at the Belle River/St. Clair Power Plant led to emission increases that would trigger PSD and NNSR requirements—the actual-to-projected actual test or the actual-to-potential test. Under the actual-to-projected-actual, emissions from the Plant before each project occurred are compared to the actual emissions projected for after the project occurred. Under the actual-to-potential test, emissions from the Plant before each project occurred are compared to the potential emissions from the plant after the project.

Which test is used in determining whether modifications lead to emissions increases triggering PSD and NNSR applicability depends on whether a facility has satisfied pre- and post-project emissions reporting requirements. If it opts to do so, the more favorable actual-to-projected-actual test may be used, but if it has not, the actual-to-potential test applies because it is the only alternative test provided by rule. 40 C.F.R. § 52.21(b)(21)(v) (providing the actual-to-future-actual test applies only when reporting requirements are met), (b)(21)(iv) (providing the actual-to-potential test applies to all projects that are not covered by the conditional test in (b)(21)(v)); 61 Fed. Reg. 38,250, 38,254 – 38,255 (July 23, 1996); *United States v. Duke Energy Corp.*, 278 F. Supp. 2d 619, 647 n.25 (M.D.N.C. 2003) (holding that Duke Energy "'opted out' of the *WEPCO* calculus" by failing to satisfy the regulatory prerequisite of submitting emissions data for a five-year period following the physical change,") *rev'd on other grounds Envtl. Def. v. Duke Energy Corp.*, 549 U.S. 561 (2007).

The federal regulations set forth the method for calculating emission increases from modifications to existing units in 40 C.F.R. § 52.21(a)(2)(iv)(c):

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

In other words, the increase is calculated as the difference between "baseline actual emissions," as defined in 40 C.F.R. § 52.21(b)(48), and "projected actual emissions," as defined in 40 C.F.R. § 52.21(b)(41), for each unit that has been modified.

For a number of the modifications at the Belle River/St. Clair Power Plant, Detroit Edison has submitted to MDEQ both pre-project reports regarding the expected emissions impact of the project and post-project reports of the actual emissions impact of the project. These reports, however, are flawed. In them, Detroit Edison improperly applied the federal regulations outlined above in ways that falsely conclude that the modifications undertaken did not lead to net emissions increases. As a result, Detroit

Edison has illegally avoided PSD and NNSR program requirements. Generally, the flaws in Detroit Edison's reports include:

1. Unsubstantiated Demand Growth Claims

In cases where Detroit Edison's emissions reports project a post-modification emissions increase in comparison to the baseline emissions, the company typically contends that the exact increase in emissions should be excluded pursuant to 40 C.F.R. 52.21(b)(41)(ii)(c) because such increase is purportedly due to demand growth causing the unit to run more often, as opposed to the modifications which reduced forced outages and derates and made the unit more cost-effective to operate. Detroit Edison provided no basis for its claims of demand growth, however, and in fact the evidence often shows that demand was *declining*. At the same time Detroit Edison made these demand growth claims, the company in many cases had projected declines in demand in filings with the MPSC.

2. Claims that the Unit Could Have Accommodated Increased Operation

Detroit Edison accompanies its demand growth exclusion claims with the assertion that any post-modification emissions increases should be ignored because the increased operation of the unit could have been accommodated before the modification. These assertions, however, are insufficient to satisfy the relevant regulatory standard, which allows emissions increases to be excluded only if they could have been accommodated "and are also unrelated to the particular project." 40 C.F.R. § 52.21(b)(48)(ii)(c). Simply claiming that an emissions increase could have been accommodated before the modification does nothing to demonstrate that the actual increases were not triggered by or related to the project. And, in many cases, the evidence strongly suggests that the modifications are what triggered those increases.

3. Use of Improper Baselines

In a number of instances, Detroit Edison improperly compares its projected post-modification emissions to a baseline that precedes the modification by more than five years. As defined in the federal regulations and in Michigan's SIP, "baseline actual emissions" are required to be measured in terms of annual emissions over any consecutive 24-month period in the proceeding five years. 40 C.F.R. § 52.21(b)(48)(i); Mich. Admin. Code R 336.2801(b)(i). An applicant may use a different time period only "upon a determination that it is more representative of normal source operation." *Id.* Yet in almost every instance where Detroit Edison has relied on a baseline more than five years before the modification, the company has failed to obtain such a determination or to provide any basis for concluding that such older baseline is "more representative of normal source operation."

4. Failure to Ensure that Baselines Reflect Normal Source Operations

Another flaw in Detroit Edison's pre- and post-modification emissions reports is that the company often fails to use consistent data regarding the rate at which each unit emits a pollutant in question. In many instances, for example, the sulfur content of the coal used in the baseline emissions years is significantly higher than it is in the post-modification years, which results in post-modification SO2 emissions appearing to be lower than pre-modification SO2 emissions. Similarly, the NOx emissions rate measured in lb/mmBtus is often higher in the pre-modification baseline years than in the post-modification years, leading to apparently lower post-modification NOx emissions. If the sulfur content or NOx emissions rate were held constant, however, there would frequently be a post-modification emissions increase, rather than the apparent decreases.

Unless the modification itself led to a reduction in sulfur content or NOx emission rates, such use of different data for the baseline years and the post-modification years is improper for two reasons. First, it means that the baseline years are no longer "representative of normal source operation" in comparison to the post-modification years. Second, allowing the use of different sulfur contents or NOx emission rates for the baseline versus the post-modification years would create a loophole for utilities like Detroit Edison, as they could avoid an NNSR triggering emissions increase by an unenforceable decision to use lower sulfur coal or operate low NOx burners for five years rather than undertaking the full level of BACT controls required by the CAA. If, as Detroit Edison has asserted in its outage reports, emissions increases that are the result of changes in fuel quality do not count for purposes of NNSR, then emissions decreases caused by changes in fuel quality (such as coal sulfur content) should not excuse a utility from NNSR requirements.

Due to the errors discussed above, Detroit Edison's pre- and post-modification emissions reports fail to demonstrate that the modifications at the Belle River/St. Clair Power Plant did not lead to significant emissions increases. In fact, the available evidence shows that such significant emissions increases did result from the modifications and, therefore, that NSR requirements were triggered. This evidence is specifically described and summarized, with tables and citations, in Appendix A of this Petition to Object and Reopen.

D. Other considerations support a finding that the Citizen Groups have demonstrated that the Title V Permit is not in compliance with the CAA.

As noted above, other factors that EPA often considers in determining whether a petitioner has demonstrated that a Title V permit is not in compliance with Clean Air Act requirements and/or should be reopened include:

> (1) the kind and quality of information underlying the agency's original finding that a prior violation occurred, (2) the information the petitioner puts forward in addition to the agency's enforcement actions, (3) the types of factual and legal issues that remain in dispute, (4) the amount of time

that has lapsed between the original decision and the current one, and (5) the likelihood that a pending enforcement case could resolve some of these issues.

Sierra Club v. EPA, 557 F.3d at 406-07. These factors support a finding that the Title V Permit for the Belle River/St. Clair Power Plant is not in compliance with the Clean Air Act.

The Citizen Groups do not have public access to the information underlying the NOV, but given the issuance of the NOV, the quality of the information underlying EPA's findings are apparently sufficient to demonstrate noncompliance with applicable standards. Regardless of the quality of the information EPA used to make its finding, however, that finding is supported by the additional evidence provided by the Citizen Groups. The underlying facts presented in this Petition are not disputable by Detroit Edison, especially given that most of the facts presented here come from Detroit Edison's own submissions to Michigan agencies.

Any legal issues in this Petition that Detroit Edison might dispute are not of a nature that would allow a determination that the Citizen Groups have not demonstrated noncompliance. The Citizen Groups have followed the terms of the underlying statute and regulations, EPA's own interpretations of them, and relevant judicial decisions in presenting the legal basis for Title V Permit's noncompliance with the CAA. Detroit Edison has no relevant defenses for its violations except to argue that its modifications at the plant do not subject it to PSD or NNSR requirements because they are RMRR or did not result in emissions increases. The Citizen Groups have preemptively addressed these potential defenses in this Petition, and shown that if raised, they are not legitimate.

The relevant available facts and legal rules lead to the conclusion that Detroit Edison is in ongoing violation of applicable PSD and NNSR requirements, and the CAA requires that the Belle River/St. Clair Power Plant be subject to a Title V compliance schedule that mandates prompt compliance. Informal EPA guidance endorses the view that a facility must be made subject to a Title V compliance schedule even under circumstances where the facility disagrees with imposition of the schedule. As explained by EPA, "if a source submits an unacceptable compliance schedule, the permitting authority may deny the permit. Alternatively the permitting authority may issue a permit with a compliance schedule with which the source does not agree. The source would then have the option of challenging the compliance schedule in state court."[80]

The simple fact that a facility disagrees, or might disagree, with EPA findings and application of its regulations to undisputed facts is not enough to prevent application of the CAA's Title V operating permit requirements. If EPA requires Petitioners to prove beyond *all* argument that the facts and legal rules require application of its provisions, then it essentially requires citizens to obtain an adjudicated decision before a petition to

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[80] E.P.A., Questions and Answers on the Requirements of Operating Permits Program Regulations, July 7, 1993, at 5-4, *available at* http://www.epa.gov/region7/air/title5/t5memos/bbrd_qa1.pdf

object to and/or reopen a Title V permit will be found sufficient. This would deprive the petitioning process outlined in the Title V of its purpose and effectiveness.

E. The Title V Permit does not include applicable MACT requirements

The Clean Air Act makes clear that MACT requirements apply not only to new and reconstructed major sources of HAPs, but also to plant modifications such as those discussed above. In particular, 42 U.S.C. § 7412(g)(2)(A) provides:

> After the effective date of a permit program under subchapter V of this chapter in any State, no person may modify a major source of hazardous air pollutants in such State, unless the Administrator (or the State) determines that the maximum achievable control technology emission limitation under this section for existing sources will be met. Such determination shall be made on a case-by-case basis where no applicable emissions limitations have been established by the Administrator.

The statute further defines "modification" as:

> any physical change in, or change in the method of operation of, a major source which increases the actual emissions of any hazardous air pollutant emitted by such source by more than a de minimis amount or which results in the emission of any hazardous air pollutant not previously emitted by more than a de minimis amount.

42 U.S.C. § 7412(a)(5). Each of the projects discussed above constitute modifications that led to a greater than *de minimis* increase in actual hazardous air pollutant emissions. However, MDEQ and Detroit Edison have not evaluated the applicability of the MACT modification provision to the Belle River/St. Clair Power Plant.

While EPA has not promulgated regulations to implement the MACT modification provision, such failure does not enable Detroit Edison and MDEQ to sidestep the clear statutory requirement that existing source MACT limits be applied to any modification that would increase HAP emissions by more than a *de minimis* amount. As the U.S. Court of Appeals for the Fifth Circuit recently explained in a case dealing with another portion of the Section 112(g) MACT requirements, "it is a fundamental precept of administrative law that an agency action, rule, or regulation 'cannot overcome the plain text enacted by Congress.'" *Sierra Club, Inc. v. Sandy Creek Energy Associates, L.P.*, 627 F.3d 134, 141 n.9 (5th Cir. 2010), *citing New Jersey v. EPA*, 517 F.3d 574, 583 (D.C. Cir. 2008). In addition, the text of Section 112(g)(2)(A) is self-executing, in that it establishes a mandatory requirement (a person may not modify a major MACT source without getting a MACT determination), and it sets a deadline for when such requirements apply (after the effective date of the Title V program in the state). As such, EPA action or inaction in establishing regulations regarding the MACT modification requirement has no impact on the improperness of Detroit Edison modifying the Belle River/St. Clair Power Plant without obtaining an existing source MACT standard determination, or on MDEQ's legal duty to include a schedule for compliance with such MACT standards in the Belle River/St. Clair Power Plant Title V Permit. Because the Title V Permit does not comply with applicable MACT requirements, EPA must object to and reopen the permit.

VI. CONCLUSION

For the foregoing reasons, EPA must object to the reissuance of and/or reopen the Belle River/St. Clair Title V Operating Permit.

Respectfully submitted,

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PETITION OF NATURAL RESOURCES DEFENSE COUNCIL AND SIERRA CLUB TO OBJECT TO ISSUANCE OF AND REOPEN A STATE TITLE V OPERATING PERMIT

APPENDIX A

In the Matter of:
Detroit Edison Belle River/St. Clair Power Plant Permit No. MI-ROP-B2796-2009
Issued by the Michigan Department of Environmental Quality

As discussed generally in Section V.C.1.d of the Petition to Object and Reopen, Detroit Edison improperly applied the law to the facts in its pre- and post-modification emissions reports to contrive results showing no emissions increases. In fact, the available evidence shows that the modifications at the Belle River/St. Clair Power Plant did lead to significant emissions increases. These facts and Detroit Edison's errors are identified more specifically below.

1. St. Clair Unit 6 – 2009 Outage

For the 2009 outage at St. Clair Unit 6, Detroit Edison's notification and reports provide the following data:

Table 1: Reported and Projected Performance for St. Clair Unit 6 – 2009 Outage[1]

	Baseline[2]	**2010 Projected**
MWh	1,839,743	1,892,000
Capacity Factor %	66.7	67.3
Heat Input	17,489,995	20,145,000
SO2 tons	9,884	11,384[3]
NOx tons[4]	2,266	2,820
PM tons	31	36.3

[1] St. Clair Unit 6 Outage Letter at p. 5 Table 1

[2] Detroit Edison used a baseline of May 2006 to April 2008 for SO2, and a NOx baseline of Jan. 2007 to Dec. 2008.

[3] Actual SO2 emissions from St. Clair Unit 6 in 2010 were 10,519.3 tons, *see* U.S. EPA, Clean Air Markets Database – Unit Emissions Report – Belle River St. Clair 2010 (May 9, 2011), attached as Ex. 28, which represents an emissions increase over the baseline that is well in excess of the threshold for triggering major source PSD and NNSR requirements.

[4] The accuracy of the NOx emissions data that Detroit Edison reported in the 2009 Outage Report is highly questionable. Detroit Edison identified a NOx emission rate of 0.28 lb/mmBtu and the total tons of 2,266 and 2,820 tons. EPA's Clean Air Markets Database, however, reports St. Clair Unit 6's NOx emissions rate as in the 0.15 to 0.17 range since 2000, and annual NOx emissions of around 1,200 tons. *See* U.S. EPA, Clean Air Markets Database – Unit Emissions Report – St. Clair 1999-2009 (Dec. 21, 2010), attached as Ex. 29. Actual NOx emissions from St. Clair Unit 6 in 2010 were 1,355.5 tons, while NOx emissions for the 2007-2008 baseline selected by Detroit Edison averaged 1,236.9 tons. As such, there has been a significant NOx increase from St. Clair Unit 6 that should have triggered PSD and NNSR requirements.

As Table 1 shows, Detroit Edison's own Planned Outage Notification predicted that, post-modification, St. Clair Unit 6 would emit 1,500 tons per year more SO2 and 554 tons per year more NOx than in the company's selected baselines of May 2006 to April 2008 for SO2, and January 2007 to December 2008 for NOx. Such emissions increases are well in excess of the emissions increase thresholds for triggering major source PSD and NNSR requirements.

Detroit Edison contends that the exact increase in emissions projected in its St. Clair Unit 6 Planned Outage Notification should be excluded pursuant to the demand growth exclusion.[5] Detroit Edison, however, has provided no basis for its demand growth claim or that the projected increased use of St. Clair Unit 6 is not related to the modifications. In fact, the available evidence reveals that the increases are not due to demand growth. Less than one month before Detroit Edison submitted its planned outage notification to MDEQ claiming that projected increased emissions were due to demand growth, the company submitted to the MPSC a filing estimating that its annual electric sales, system output, and coincident peak demand would be lower in 2010 and future years than in the baseline years of 2006, 2007, and 2008. In particular, Detroit Edison's PSC filing reported the following data:

Table 2: Jan. 2009 Detroit Edison Report and Projection of Electric Sales and Demand[6]

	2006	2007	2008	2010 Projected
Service Area Sales	53,528	54,355	52,321	49,315
Bundled Sales	50,178	52,117	50,912	47,368
System Output	57,348	58,128	55,863	52,698
Maximum Demand	12,901	12,229	11,251	11,479
Load Factor %	50.7	54.3	56.7	52.4

These projections undermine Detroit Edison's unsupported claim that projected emissions increases at Unit 6 are due to demand growth, because no such growth is projected. Detroit Edison's claim that St. Clair Unit 6 could have accommodated these emissions even before the 2009 modification fails because such claim does not demonstrate that the emissions increases are not related to the modification. In fact, there is strong evidence that the emissions increase is related to the modification, as the heat input projected for 2010 is significantly higher than the heat input reported on the Clean Air Markets Database for St. Clair Unit 6 every year since at least 1999. Similarly, the projected SO2 emissions for 2010 are higher than such emissions in every year since 2002 with the exception of 2005. Such data demonstrates that either St. Clair Unit 6 was not capable of running more and emitting more pollution before the modifications, or that the increases in operating hours and resulting jump in emissions occurred because of the modification.

[5] St. Clair Unit 6 Outage Letter at p. 5 Table 1.

[6] *In re Application of Detroit Edison Company for Authority to Increase Its Rates*, Mich. PSC Case. No. U-15768, Testimony of Sherrie L. Siefman (Jan. 26, 2009) at Ex. A-12, attached as Ex. 30.

The available evidence is clear that Detroit Edison modified St. Clair Unit 6 in ways that increased emissions and triggered NSR requirements. As such, addition of a schedule of compliance with the applicable PSD and NNSR requirements into the Title V Permit is required.

2. St. Clair Unit 6 – 2007 Outage

For the 2007 outage at St. Clair Unit 6, Detroit Edison's notification and reports provide the following data:

Table 3: Reported and Projected Performance for St. Clair Unit 6 – 2007 Outage

	1998-1999 Baseline[7]	2010 Projected[8]	2008 Actual[9]	2009 Actual[10]
MWh	1967060	1839000	1611268	1422052
Capacity Factor	70.0	65.4	66.9	50.4
Heat Input	19995434	19549000	15448671	14132852
SO2 lb/mmBtu	1.31	1.31	.53	1.06
NOx lb/mmBtu	.47	.15	.16	.17
PM lb/mmBtu	.01	.01	.002	.0001
SO2 tons	13,081	12,787	8,653	7,457
NOx tons	4,699	1,466	1,216	1,193
PM tons	89	87	13	1

The primary shortcoming in Detroit Edison's reporting regarding the 2007 Outage at St. Clair Unit 6 is that the company relies on a 1998-1999 baseline that is eight to nine years before the modifications in question. As explained in Section V.C.1.d in the Petition, the baseline emissions must be for a 24-month period within five years of the modification unless there is a determination that more distant years are more representative of normal operating conditions. No such determination or showing has been made here.

Detroit Edison recently proposed a more current emissions baseline for St. Clair Unit 6 of January 2004 to December 2005.[11] Using that baseline, and adjusting the 2010 projections for the same sulfur content and NOx emissions rates as used in the baseline, provides the following results:

[7] St. Clair Unit 6 2007 Outage at p. 5 Table 1.
[8] *Id.*
[9] Ltr. from Wayne A. Rugenstein, Detroit Edison, to Teresa Seidel, MDEQ, 2008 NSR Emissions Report for St. Clair Power Plant (Feb. 22, 2009), at 3-4, 9 and Table SC6-1, attached as Ex. 31 (hereinafter "2008 NSR Emissions Report for St. Clair").
[10] Ltr. from Kelly L. Guertin, Detroit Edison, to Teresa Seidel, MDEQ, 2009 NSR Emissions Report for St. Clair Power Plant (Feb. 26, 2010), at 4, 10 and Table SC6-1, attached as Ex. 32 (hereinafter "2009 NSR Emissions Report for St. Clair").
[11] 2009 NSR Emissions Report for St. Clair at Table SC6-1.

Table 4: Reported and Projected Performance for St. Clair Unit 6 – 2007 Outage

	2004-2005 Baseline	2010 Projected
MWh	?	1839000
Capacity Factor	?	65.4
Heat Input	18585749	19549000
SO2 lb/mmBtu	1.23	1.31
NOx lb/mmBtu	.16	.16
PM lb/mmBtu	.0095	.01
SO2 tons	11,386	12,002
NOx tons	1,514	1,563
PM tons	88	87

As Table 4 shows, the 2010 projected emissions for SO2 and NOx are higher than the emissions baseline selected by Detroit Edison that is within the five years preceding the 2007 modifications to St. Clair Unit 6. As such, the evidence shows that the 2007 modifications should have triggered NSR requirements at Unit 6. Due to this, addition of a schedule of compliance with the applicable PSD and NNSR requirements into the Title V Permit is required.

3. St. Clair Unit 7 – 2010 Outage

For the 2010 outage at St. Clair Unit 7, Detroit Edison's notification utilizes different baseline periods for SO2, NOx, and PM, and projects the following:

Table 5: Reported St. Clair Unit 7 Performance – 2010 Outage[12]

	SO2 Baseline Jan. 2005 - Dec. 2006	NOx Baseline Apr. 2007 – Mar. 2009	PM Baseline Aug. 2008 – July 2010	2013 Projected
MWh	2,395,463	2,702,070	2,391,352	2,427,000
Capacity Factor	60.8	68.5	60.7	61.6
Heat Input	23,700,000	27,000,000	23,700,000	25,800,000
SO2 lb/mmBtu	1.35			1.053
NOx lb/mmBtu		.186		.168
PM lb/mmBtu			.025	.021
SO2 tons	16,030			13,588
NOx tons		2,516		2,170
PM tons			297	297

Detroit Edison's planned outage notification for the 2010 outage at St. Clair Unit 7 fails to demonstrate a lack of an emissions increase for a few reasons. First, the SO2 baseline is more than five years before the modification under evaluation, and the required demonstration and determination necessary for using an older baseline has not been provided. The modification here began in mid-September 2010 and ended in mid-

[12] St. Clair Unit 7 2010 Outage at Table 1.

December 2010, so any baseline would have to start in September 2005 or later in the absence of such a demonstration and determination.

Second, the notification assumes lower lb/mmBtu emission rates for SO2, NOx, and PM for 2013 than in the baseline years. Yet, in the absence of an explanation that the modification at issue would lead to lower emission rates for those pollutants, the same emission rates must be assumed for each pollutant in order for the baseline years to be representative of normal operations. Third, supporting documentation provided by Detroit Edison to MDEQ demonstrates clearly that the modifications made at Unit 7 during the 2010 outage will lead to an emissions increase. For example:

#6 Feedwater Heater Replacement:[13] A 2007 Detroit Edison report explained that the #6 feedwater heater had "exceeded normal industry life," "reached 'end-of-life,'" and had 26.4% of its tubes plugged as of January 2007. The plugged tubes were estimated to impose a heat rate penalty of 80 Btu/KWHr, there were expected to be five unit derates of 40MW lasting five days each per year due to the need to repair failing tubes in the feedwater heater, and there were projected to be five unit heat rate penalties of 162 Btu/KWHr lasting five days each per year due to the need to repair the feedwater heater. In addition, the loss of the #6 feedwater heater was projected to reduce unit heat by 1.5% and to increase unit operating cost by approximately $650,000 per year starting in 2008. Replacement of the #6 feedwater heater is expected to eliminate these plugged tubes, derates and heat rate penalties.

#4 Feedwater Heater Replacement:[14] A 2007 Detroit Edison report explained that the #4 feedwater heater had "exceeded normal industry life," and had 13% of its tubes plugged as of January 2007. The plugged tubes were estimated to impose a heat rate penalty of 14 Btu/KWHr, there were expected to be three unit derates of 150MW lasting two days each per year due to the need to repair failing tubes in the feedwater heater, and there were projected to be five unit heat rate penalties of 80 Btu/KWHr lasting five days each per year due to the need to repair the feedwater heater. In addition, the loss of the #4 feedwater heater was projected to reduce unit heat by 2% and to increase unit operating cost by approximately $875,000 per year starting in 2008. Replacement of the #4 feedwater heater is expected to eliminate these plugged tubes, derates and heat rate penalties.

Water Wall Tubing Replacement:[15] The replacement of 1,435 square feet of "'high priority' thermally-shocked, quench-cracked water wall tubes" is projected to increase unit reliability by avoiding two tube leak forced outages per year. Each outage would last 3.25 days, at a cost of $300,000 per day, or $2 million per year, due to lost generation.

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[13] Ltr. from Barry Marietta, Detroit Edison to Gerry Avery, MDEQ, Re: Follow-Up Information – 2010 Planned Outage Notification – St. Clair Power Plant (B2796), Unit 7 (Aug. 30, 2010), Attachment A at Project ID 3305, attached as Ex. 33 (hereinafter "St. Clair Unit 7 2010 Follow-Up Info").

[14] *Id.* at Project ID 3576.

[15] *Id.* at 5679.

Burner Replacement:[16] This project replaced corroded burner assemblies, which were a contributor to poor combustion performance, unit derates, and accelerated boiler pluggage. The replacements were projected to increase unit availability by 0.5%, which is valued at $320,000 per year, improve unit heat rate by 1%, at a value of $440,000 per year, avoid one of two five day long boiler wash outages, at a value of $970,000 per year, and reduce derates from an average of 50MW for 600-3800 hours per year to 25MW for 600-3800 hours per year.

Economizer Expansion Joint Replacement:[17] This project was designed to address significant deterioration in the economizer expansion joint, which was leading to derates and accelerated furnace pluggage. Replacement of the joint was projected to improve unit availability by 0.5% and to improve unit heat rate by 2%, with the value of $320,000 and $880,000 per year, respectively.

Online Detonation Cleaning:[18] This project replaced eight sootblowers with four detonation cleaners, thereby increasing boiler efficiency by 0.21%, and causing a net generation increase of 5-10MW. The project was also projected to reduce economizer tube leak outages by two to three days per year and eliminate derates of 30-50MW for 400 hours per year.

In short, Detroit Edison's own internal documentation shows that the modifications that occurred as part of the 2010 outage at St. Clair Unit 7 increased capacity and availability, reduced outages and derates and, therefore, caused the unit to operate more frequently and emit more pollution after the modifications than before. Such impacts undermine Detroit Edison's claims that the 2010 Outage at St. Clair Unit 7 would not significantly increase emissions and demonstrates that the modifications trigger the NSR requirements that must be addressed in this Title V Permit.

4. St. Clair Unit 7 – 2007 Outage

Detroit Edison's Planned Outage Notification and Post-Outage Reports provide the following analysis regarding the baseline and post-modification emissions for the modifications that occurred during the 2007 outage at St. Clair Unit 7:

[16] *Id.* at Project ID 4800.
[17] *Id.* at Project ID 4815.
[18] *Id.* at Project ID 3619.

Table 6: Reported St. Clair Unit 7 Performance – 2007 Outage

	2003-2004 Baseline[19]	2007 Projected[20]	2007 Actual[21]	2008 Actual[22]	2009 Actual[23]
MWh	2681957	2750000	2232121	2635600	2328878[24]
Capacity Factor	68.0	69.8	56.6	66.9	52.0
Heat Input	26009497	28406000	22349569	26622025	21765140
SO2 lb/mmBtu	1.41	1.41	1.15	1.07	1.04
NOx lb/mmBtu	.18	.18	.19	.19	.18
PM lb/mmBtu	.03	.03.	.02	.02	.02
SO2 tons	18,276	19,960	12,883	14,303	11,346
NOx tons	2,320	2,534	2,072	2,481	1,997
PM tons	326	356	192	302	252

As Table 6 shows, Detroit Edison's own Planned Outage Notification predicted that, post-modification, St. Clair Unit 7 would emit 1,682 more tons per year of SO2, 214 more tons per year of NOx, and 30 more tons per year of PM than in the company's selected 2003 to 2004 baseline. Such emissions increases are well in excess of the emissions increase thresholds for triggering major source PSD and NNSR requirements. While actual 2007 emissions ended up being lower than projected, that is because the outage occurred during 2007, meaning that St. Clair Unit 7 did not operate for at least 10 weeks that year. As such, the actual emissions in 2007 do not undermine the clear projection of an emissions increase that should have required Detroit Edison to go through PSD and NNSR permitting for St. Clair Unit 7.

Detroit Edison contends that the exact increase in emissions projected in its St. Clair Unit 7 2007 Planned Outage Notification should be excluded pursuant to the demand growth exclusion. The company, however, has provided no basis for its demand growth claim or that the projected increased use of St. Clair Unit 7 is not the related to the modifications. Similarly, Detroit Edison's claim that St. Clair Unit 7 could have accommodated these emissions even before the 2009 modification also falters because, as explained in Section V.C.1.d in the Petition, such claim does not demonstrate that the emissions increases are not related to the modification.

In fact, the actual heat input for Unit 7 in 2008 was higher than it had been for that Unit in any year since 2000. Similarly, actual NOx emissions in 2008 were 161 tons higher than in the 2003-2004 baseline, and higher than any year since 2000 for St. Clair Unit 7. SO2 emissions were lower in 2008 than in the 2003-2004 baseline, but only

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[19] St. Clair Unit 7 2007 Outage at p.5 Table 1.
[20] *Id.*
[21] Ltr. from Wayne A. Rugenstein, Detroit Edison to Teresa Seidel, MDEQ, 2007 NSR Emissions Report for St. Clair Power Plant (Feb. 25, 2008), at pp. 5, 19 and Table SC7-1, attached as Ex. 34 (hereinafter "2007 NSR Emissions Report for St. Clair").
[22] 2008 NSR Emissions Report for St. Clair at pp. 4, 10 and Table SC7-1.
[23] 2009 NSR Emissions Report for St. Clair at pp. 4-5, 11 and Table SC7-1.
[24] Detroit Edison's 2009 NSR Emissions Report includes an unlikely 184,291 MWh for St. Clair Unit 7 in 2009. Therefore, the Citizen Groups have used the MWh reported in the U.S. EPA's Clean Air Markets Database instead.

because the sulfur content of the coal was lower. Had the same sulfur content of coal been assumed, as is required to ensure that the baseline is representative of actual performance, St. Clair Unit 7 would have emitted 18,768 tons of SO2 in 2008, which would be an increase of 592 tons. Such data demonstrates that either St. Clair Unit 7 was not capable of running more and emitting more pollution before the modifications, or that the increases in operating hours and resulting jump in emissions occurred because of the modification.

In an effort to avoid the clear increase in NOx emissions post-modification, Detroit Edison attempted in its 2008 NSR Emissions Report to change the baseline period to January 2000 to December 2001. Such a baseline, however, is more than five years before the modification under evaluation, and there has been no determination and no evidence has been presented that such years are "more representative of actual operating performance" than the baseline emission years that Detroit Edison initially selected. The modification here began in January 2007 and ended in mid-March 2007, so any baseline would have to start in March 2002 or later.

Detroit Edison's effort to obfuscate data that shows clear emissions increases is also undermined by the fact that the company's internal documentation regarding the replacement of the 5th stage feedwater heater during the 2007 outage projected exactly the kinds of changes that would lead to emissions increases.[25] In particular, Detroit Edison found that 100% of the tubes that were checked in the heater had reached "end-of-life" condition, with more than 80% wall loss. Loss of the 5th stage feedwater heater was causing a 19MW derate at Unit 7, while the loss of the #7 feedwater heater (which was also replaced during the 2007 Outage), was causing a 6MW derate. Replacement of the #5 feedwater heater would end that derate and also address a 14 Btu/KWhr heat rate loss caused by the loss of the heater.

In short, the available evidence is clear that Detroit Edison modified St. Clair Unit 7 during the 2007 Outage in ways that increased emissions and triggered NSR requirements. As such, addition of a schedule of compliance with the applicable PSD and NNSR requirements into the Title V Permit is required.

5. St. Clair Unit 3 – 2004 Outage

Detroit Edison's Planned Outage Notification and Post-Outage Reports identify the 2004 modification at St. Clair Unit 3 as having led to a 5-8MW capacity increase, and the following unit performance:

[25] St. Clair Unit 7 2010 Follow-up Info., Attachment A at Project ID 3281.

Table 7: Reported and Projected St. Clair Unit 3 Performance – 2004 Outage

	1998-1999 Baseline[26]	2007 Projected[27]	2005 Actual[28]	2006 Actual[29]	2007 Actual[30]	2008 Actual[31]	2009 Actual[32]
MWh	907,950	797,371	737,852	809,759	929,395	922,207	767,108
Capacity Factor	63.6	53.2	50.1	55.0	63.2	62.7	52.0
Heat Input	10710698	8635408	8209177	9039065	10251769	10051146	8671856
SO2 lb/mmBtu	1.27	1.27	.78	.89	.87	1.09	.61
NOx lb/mmBtu	.68	.34	.37	.51	.40	.45	.41
PM lb/mmBtu	.00	.00	.00	.00	<.01	.01	.00
SO2 tons	6,816	5,495	3,205	4,032	4,451	5,468	2,630
NOx tons	3,643	1,468	1,527	2,283	2,067	2,277	1,772
PM tons	33	15	7	<1	<1	<1	5

Detroit Edison's pre- and post-modification submittals are flawed in at least two important ways. First, the 1998 to 1999 baseline is more than five years before the modification under evaluation, and the requisite explanation for why an earlier baseline is purportedly more representative has not been provided. The modification here began in mid-February 2004 and ended in mid-May 2004, so absent such explanation, any baseline would have to start in May 1999 or later. Second, the annual megawatt hours reported in the submittals are inconsistent with those reported in EPA's Clean Air Markets Database for all five post-modification years. Correcting for these errors leads to the following:

Table 8: Corrected St. Clair Unit 3 Performance

	2000-2001 Baseline[33]	2007 Projected	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual
MWh[34]	886,488	797,371	834,245	909,731	1,036,490	1,031,142	863,212
Capacity Factor	?	53.2	50.1	55.0	63.2	62.7	52.0
Heat Input	7909894	8635408	8209177	9039065	10251769	10051146	8671856
SO2	1.16[35]	1.27	.78	.889	.87	1.09	.61

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[26] St. Clair Unit 3 2004 Outage at p. 5 Table 1.
[27] *Id.*
[28] Ltr. from Wayne A. Rugenstein, Detroit Edison to Teresa Seidel, MDEQ, 2005 NSR Emissions Report for St. Clair Power Plant – Unit 3 (Feb. 20, 2006), at p. 3 Table 1, attached as Ex. 35.
[29] Ltr. from Wayne A. Rugenstein, Detroit Edison to Teresa Seidel, MDEQ, 2006 NSR Emissions Report for St. Clair Power Plant – Unit 3 (Feb. 15, 2007), at p. 3 Table 1, attached as Ex. 36.
[30] 2007 NSR Emissions Report for St. Clair Power Plant at pp. 4, 16 Table SC3-1.
[31] 2008 NSR Emissions Report for St. Clair Power Plant at pp. 3, 7 Table SC3-1.
[32] 2009 NSR Emissions Report for St. Clair Power Plant at pp. 3, 8 Table SC3-1.
[33] U.S. EPA, Clean Air Markets Database – Unit Emissions Report – St. Clair 1999-2009 (Dec. 21, 2010).
[34] *Id.*
[35] This figure was calculated from the annual average tons of SO2 emitted in 2001-2002 baseline, multiplied by 2000 lbs/ton, and then divided by the average annual heat input for the 2001-2002 baseline.

lb/mmBtu							
NOx lb/mmBtu	.65	.34	.37	.51	.40	.45	.41
PM lb/mmBtu	?	.00	.00	.00	<.01	.01	.00
SO2 tons	4,589.85	5,495	3,205	4,032	4,451	5,468	2,630
NOx tons	2,579.3	1,468	1,527	2,283	2,067	2,277	1,772
PM tons	?	15	7	<1	<1	<1	5

The above data provides evidence of an NSR-triggering emissions increase from the 2004 modification to St. Clair Unit 3 in a few ways. First, the annual heat input for St. Clair Unit 3 is higher in all five post-project years that it is in the baseline years, and the megawatt hours for the unit is higher in three out of five of those years. Second, annual SO2 emissions from Unit 3 were 878.15 tons higher in 2008 than in the 2001-2002 baseline, and were projected to be 905.15 tons higher in 2007 than in the 2001-2002 baseline. While actual annual SO2 emissions were lower in 2005, 2006, 2007, and 2009 than in the 2001-2002 baseline, this is only because lower sulfur content coal was used in those years than in the baseline. Holding the sulfur content of the coal constant, which is necessary for the baseline years to be considered representative of normal operations, would lead to the conclusion that annual SO2 emissions were higher at St. Clair Unit 3 every year after the modification than they were during the baseline years. Similarly, for NOx, emissions were lower in post-modification years only because a low-NOx burner began operating in 2004. Once again, for the baseline years to be considered representative of normal operations the NOx emission rate must be held constant. Doing so leads to the conclusion that NOx emissions increased after and as a result of the 2004 modifications at Unit 3.

The available evidence is clear that Detroit Edison modified St. Clair Unit 3 during the 2004 outage in ways that increased emissions and triggered NSR requirements. As such, addition of a schedule of compliance with the applicable PSD and NNSR requirements into the Title V ROP is required.

6. St. Clair Unit 2 – 2009 Outage Notification

Detroit Edison's Planned Outage Notification provides the following analysis regarding the baseline and projected post-modification emissions for the modifications that occurred during the 2009 outage at St. Clair Unit 2:

Table 9: Reported and Corrected St. Clair Unit 2 Performance

	2004-2005 Baseline[36]	2005-2006 Corrected Baseline[37]	2010 Projected[38]
MWh	792592	837306	843000
Capacity Factor	55.8	?	59.4
Heat Input	8789894	8358647	9475000
SO2 lb/mmBtu	0.86	0.83	0.63
NOx lb/mmBtu	0.37	0.37	0.33
PM lb/mmBtu	0.0071	?	0.0071
SO2 tons	3,765	3,468.5	2,985
NOx tons	1,628	1,557.75	1,563
PM tons	31	?	33

Detroit Edison's analysis is flawed here for two reasons. First, the 2004 to 2005 baseline is more than five years before the modification under evaluation, and the requisite explanation for and determination that an earlier baseline is purportedly more representative has not been provided. The modification here began in October 2009 and ended at the end of November 2009, so any baseline would have to start in December 2004 or later. The Citizen Groups have added to Table 9 above a corrected baseline that is within five years of the modification at issue.

Second, regardless of whether the corrected baseline is used, the data shows no emissions increase for SO2 or NOx only because it assumes a lower coal sulfur content and a lower lb/mmBtu NOx emission rate in 2010 than in the baseline. Adjusting for the same sulfur content in 2010 as during the baseline would result in projected SO2 emissions of 4,074 tons, which would constitute a 606 ton per year increase in SO2 emissions. Similarly, using the same NOx emission rate would result in projected 2010 NOx emissions of 1,752 tons, which represents an increase of 195 tons. In the absence of any evidence that the 2009 modifications would lead to a decrease in the SO2 or NOx lb/mmBtu emission rate, the same rates must be used for the baseline and the projected emissions year in order for the baseline to represent normal operating conditions for purposes of the NSR emissions increase analysis.

The available evidence shows that Detroit Edison modified St. Clair Unit 2 during the 2009 outage in ways that increased emissions and triggered NSR requirements. As such, addition of a schedule of compliance with the applicable PSD and NNSR requirements into the Title V Permit is required.

[36] 2009 St. Clair Unit 2 Outage at p. 5 Table 1.
[37] US EPA, Clean Air Markets Database – Unit Emissions Report – St. Clair 1999-2009 (Dec. 21, 2010).
[38] 2009 St. Clair Unit 2 Outage at p. 5 Table 1.

7. St. Clair Unit 2 – 2006 Outage

Detroit Edison's Planned Outage Notification provides the following analysis regarding the baseline and projected post-modification emissions for the modifications that occurred during the 2006 outage at St. Clair Unit 2:

Table 10: Reported and Projected St. Clair Unit 2 Performance - 2006 Outage

	2004-2005 Baseline[39]	2008 Projected[40]	2006 Actual[41]	2007 Actual[42]	2008 Actual[43]	2009 Actual[44]
MWh	9475000	700000	737277	869872	842076	722363
Capacity Factor	55.8	49.3	52.0	61.3	59.4	51.0
Heat Input	8789894	8244000	8282765	9587680	9255553	8298443
SO2 lb/mmBtu	.86	.86	.91	.76	.59	.63
NOx lb/mmBtu	.37	.37	.37	.375	.382	.392
PM lb/mmBtu	.01	.01	.01	.004	.005	.006
SO2 tons	3,765	3,531	3,748	3,624	2,751	2,608
NOx tons	1,628	1,527	1,533	1,800	1,770	1,626
PM tons	31	29	24	23	23	25

Detroit Edison's own data shows post-modification NOx emissions increases in 2007 and 2008 of 172 and 142 tons, respectively. Such increases are far in excess of the significant increase threshold and, therefore, NSR requirements should have been complied with as part of the 2006 Outage at St. Clair Unit 2. In addition, assuming the use of the same sulfur content coal would lead to SO2 emissions of 4,122 tons in 2007 and 3,979 tons in 2008, which equate to increases of 357 tons in 2007 and 214 tons in 2008, both of which exceed the significant increase thresholds that trigger NSR requirements.

Detroit Edison attempts to avoid the 2007 NOx emissions increase by claiming that the exact amount of the increase is due to demand growth.[45] The company, however, has provided no basis for its demand growth claim or that the projected increased use of St. Clair Unit 2 is not the related to the modifications. Similarly, Detroit Edison's claim that St. Clair Unit 2 could have accommodated these emissions even before the 2006 modification also falters because, as explained in Section V.C.1.d above, such claim does

[39] 2006 St. Clair Unit 2 Planned Outage at p. 5 Table 1.
[40] *Id.*
[41] Ltr. from Wayne A. Rugenstein, Detroit Edison to Teresa Seidler, MDEQ, Re: 2006 NSR Emissions Report for St. Clair Power Plant – Unit 2 (Feb. 15, 2007), at p. 3 Table 1, attached as Ex.37.
[42] 2007 NSR Emissions Report for St. Clair Power Plant at pp. 2-3, 11 Table SC2-1.
[43] 2008 NSR Emissions Report for St. Clair Power Plant at pp. 2-3, 6 Table SC2-1.
[44] 2009 NSR Emissions Report for St. Clair Power Plant at pp. 3, 7 Table SC2-1.
[45] 2007 NSR Emissions Report for St. Clair Power Plant at 3.

not demonstrate that the emissions increases are not related to the modification. In fact, Unit 2's 2007 and 2008 NOx emissions were the highest they have been since 1999, and the heat input and megawatt hours of power produced by Unit 2 were the highest in 2007 and 2008 that they have been since 2001. Such data demonstrates that either St. Clair Unit 2 was not capable of running more and emitting more pollution before the modifications, or that the increases in operating hours and resulting jump in emissions occurred because of the modification.

Detroit Edison also notes that the 2006 outage at St. Clair Unit 2 included upgrades to the low-NOx burners in that Unit, which would purportedly allow for greater reductions in NOx emissions.[46] NOx emissions, however, have been higher from St. Clair Unit 2 every year since the 2006 outage than before it.

For the 2008 NOx increase, Detroit Edison does not raise a demand growth claim. Instead, the company proposes a new emissions baseline of October 2006 to September 2008.[47] This response is, of course, nonsensical, as the proposed new baseline is both after the 2006 outage and overlaps with the 2007 and 2008 periods in which a post-modification NOx increase occurred.

The available evidence is clear that Detroit Edison modified St. Clair Unit 2 during the 2006 Outage in ways that increased emissions and triggered NSR requirements. As such, addition of a schedule of compliance with the applicable PSD and NNSR requirements into the Title V ROP is required.

8. Belle River Unit 1 – 2008 Outage

For the 2008 outage at Belle River Unit 1, Detroit Edison's notification and reports provide the following data:

Table 11: Reported and Projected Belle River Unit 1 Performance – 2008 Outage

	2000-2001 Baseline[48]	2009 Projected[49]	2009 Actual[50]
MWh	4684486	3771000	4738290
Capacity Factor	85.5	68.8	85.0
Heat Input	53951964	38272000	47003351
SO2 lb/mmBtu	0.55	0.55	0.58
NOx lb/mmBtu	0.27	0.18	0.23
PM lb/mmBtu	0.004	0.004	0.0019
SO2 tons	14,823	10,515	13,595
NOx tons	7,377	3,444	5,324
PM tons	111	79	45

[46] *Id.*

[47] 2008 NSR Emissions Report for St. Clair Power Plant at 2-3.

[48] Belle River Unit 1 2008 Outage at p. 6 Table 1.

[49] *Id.*

[50] Ltr. from Kelly L. Geurtin, Detroit Edison to Teresa Seidel, MDEQ, Re: 2009 NSR Emissions Report for Belle River Power Plant (Feb. 26, 2010), at pp. 3, 5 and Table BR1-1, attached as Ex. 38 (hereinafter "2009 NSR Emissions Report for Belle River Power Plant").

This analysis is flawed because Detroit Edison attempts to use a baseline that precedes the 2008 modifications by seven to eight years, rather than being within the five years called for the in NSR regulations. Detroit Edison offers an explanation for using such a distant baseline, contending that a decline in manufacturing and increase in customers opting to purchase their electricity at times from Alternative Energy Suppliers under the state's electric choice law during the mid-2000s made those years less representative of normal operations at Belle River Unit 1 than earlier years were.[51] This explanation fails, however, because Detroit Edison's bundled sales in 2006 and 2007 (50,178GWh and 52,117GWh) were nearly identical to those for 2000 and 2001 (52,407GWh and 50,248GWh). The fact that the capacity factor at Belle River Unit 1 is somewhat lower in 2006 and 2007 than in 2000 and 2001 does not appear to have any connection to overall Detroit Edison sales or energy demand. Instead, the lower capacity factor is likely due to the type of unit equipment degradation that modifications such as those carried out during the 2008 outage address.

Table 12: Corrected Belle River Unit 1 Performance

	2006-2007 Baseline[52]	2009 Projected	2009 Actual	2010 Actual[53]
MWh	4518398	3771000	4738290	4608765
Capacity Factor	?	68.8	85.0	?
Heat Input	42779288	38272000	47003351	43926807
SO2 lb/mmBtu	0.57	0.55	0.58	0.59
NOx lb/mmBtu	0.205	0.18	0.23	0.22
PM lb/mmBtu	?	.004	.0019	?
SO2 tons	12,144	10,515	13,595	12,992.3
NOx tons	4,527	3,444	5,324	4,888.7
PM tons	?	79	45	?

As the above data shows, using a baseline within five years of the 2008 modifications at Belle River Unit 1 reveals that there were post-modification SO2 and NOx emissions increases in 2009 and 2010. These increases are more than adequate to trigger the NSR requirements for Belle River Unit 1.

9. Belle River Unit 2 – 2010 Outage

For the 2010 outage at Belle River Unit 2, Detroit Edison's notification provides the following data:

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[51] Belle River Unit 1 2008 Outage at 2.

[52] U.S. EPA Clean Air Markets Database, Unit Emissions Report – Belle River Power Plant – 1998 to 2009 (Dec. 28, 2010), attached as Ex. 39.

[53] U.S. EPA Clean Air Markets Database, Unit Emissions Report – Belle River St. Clair – 2010 (May 9, 2011).