ORAL ARGUMENT SCHEDULED FOR APRIL 13, 2012

No. 11-1302 (and consolidated cases)
COMPLEX

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

EME Homer City Generation, L.P., et al.,
Petitioners,
v.
Environmental Protection Agency, et al.,
Respondents.

On Petition for Review of a Final Order of the
U.S. Environmental Protection Agency

FINAL BRIEF OF INDUSTRY AND LABOR PETITIONERS

Gregory G. Garre
Claudia M. O'Brien
Lori Alvino McGill
Jessica E. Phillips
Katherine I. Twomey
Stacey VanBelleghem
Latham & Watkins LLP
555 Eleventh Street, NW
Suite 1000
Washington, DC 20004-1304
(202) 637-2200
gregory.garre@lw.com

Counsel for Petitioner EME Homer City Generation, LP

Peter D. Keisler
Roger R. Martella, Jr.
C. Frederick Beckner III
Timothy K. Webster
R. Juge Gregg
Sidley Austin LLP
1501 K Street, NW
Washington, DC 20005
(202) 736-8000
pkeisler@sidley.com

F. William Brownell
Hunton & Williams LLP
2200 Pennsylvania Avenue, NW
Washington, DC 20037
(202) 955-1500
bbrownell@hunton.com

Counsel for Petitioners Luminant Generation Company LLC et al.

Final March 16, 2012

Additional counsel listed on following pages

Janet J. Henry, Deputy General Counsel
American Electric Power Service Corp.
1 Riverside Plaza
Columbus, OH 43215
(614) 716-1612
jjhenry@aep.com

Counsel for Petitioners AEP Texas North Co., Appalachian Power Co., Columbus Southern Power Co., Indiana Michigan Power Co., Kentucky Power Co., Ohio Power Co., Public Service Co. of Oklahoma, Southwestern Electric Power Co.

William M. Bumpers
Joshua B. Frank
Megan H. Berge
Baker Botts LLP
1299 Pennsylvania Avenue, NW
The Warner, Suite 1300 West
Washington, DC 20004-2400
(202) 639-7700
william.bumpers@bakerbotts.com

Counsel for Petitioners Consolidated Edison Company of New York, Inc., Entergy Corp., Northern States Power Co. – Minnesota, Southwestern Public Service Co., Western Farmers Electric Cooperative

Steven G. McKinney
Balch & Bingham LLP
1901 Sixth Avenue North
Suite 1500
Birmingham, AL 35203-4642
(205) 251-8100
smckinney@balch.com

Counsel for Petitioner Alabama Power Co.

P. Stephen Gidiere, III
Balch & Bingham LLP
1901 Sixth Avenue North
Suite 1500
Birmingham, AL 35203-4642
(205) 251-8100
sgidiere@balch.com

Counsel for Petitioner Luminant Generation Company LLC et al.

Terese T. Wyly
Balch & Bingham LLP
1310 Twenty Fifth Avenue
Gulfport, MS 39501-1931
(228) 864-9900
twyly@balch.com

Counsel for Petitioner Mississippi Power Co.

Richard Alonso
Jeffrey R. Holmstead
Bracewell & Giuliani LLP
2000 K Street, NW, Suite 500
Washington, DC 20006-1872
(202) 828-5800
richard.alonso@bgllp.com

Counsel for Petitioner GenOn Energy, Inc.

Gary C. Rikard
Butler, Snow, O'Mara, Stevens & Cannada, PLLC
6075 Poplar Avenue
Fifth Floor
Memphis, TN 38119
(901) 680-7200
gary.rikard@butlersnow.com

Counsel for Petitioner South Mississippi Electric Power Association

Peter P. Garam
Consolidated Edison Company of New York, Inc.
Room 1815-S
4 Irving Place
New York, NY 10003
(212) 460-2985
garamp@coned.com

Counsel for Petitioner Consolidated Edison Company of New York, Inc.

Robert J. Alessi
Dewey & LeBoeuf LLP
99 Washington Avenue
Suite 2020
Albany, NY 12210
(518) 626-9400
ralessi@dl.com

Counsel for Petitioner Environmental Energy Alliance of New York, LLC

Kyra Marie Fleming, Deputy General Counsel
DTE Energy Resources, Inc.
414 South Main Street
Suite 600
Ann Arbor, MI 48104
(734) 302-4898
flemingk@dteenergy.com

Counsel for Petitioner DTE Stoneman, LLC

Chuck D'Wayne Barlow,
Assoc. General Counsel
Entergy Services, Inc.
PO Box 1640
Jackson, MS 39215-0000
(601) 969-2542
cbarlow@entergy.com

Counsel for Petitioner Entergy Corp.

Richard G. Stoll
Brian H. Potts
Julia L. German
Foley & Lardner LLP
3000 K Street, NW, 6th Floor
Washington, DC 20007-5143
(202) 672-5300
rstoll@foley.com

Counsel for Petitioner Wisconsin Public Service Corp.

Robert A. Manning
Joseph A. Brown
Mohammad O. Jazil
Hopping Green & Sams, P.A.
119 South Monroe Street
Suite 300
Tallahassee, FL 32301
(850) 222-7500
robertm@hgslaw.com

Counsel for Petitioner Environmental Committee of the Florida Electric Power Coordinating Group, Inc.

James S. Alves
Gary V. Perko
Hopping Green & Sams, P.A.
119 South Monroe Street
Suite 300
Tallahassee, FL 32301
(850) 222-7500
jalves@hgslaw.com

Counsel for Petitioner Gulf Power Co.

Eric J. Murdock
Hunton & Williams LLP
2200 Pennsylvania Avenue, NW
Washington, DC 20037
(202) 955-1500
emurdock@hunton.com

Counsel for Petitioner DTE Stoneman, LLC

William L. Wehrum, Jr.
Hunton & Williams LLP
2200 Pennsylvania Avenue, NW
Washington, DC 20037
(202) 955-1500
wwehrum@hunton.com

Counsel for Petitioner National Rural Electric Cooperative Association

Andrea Bear Field
Norman W. Fichthorn
E. Carter Chandler Clements
Hunton & Williams LLP
2200 Pennsylvania Avenue, NW
Washington, DC 20037
(202) 955-1500
afield@hunton.com

Counsel for Petitioner Utility Air Regulatory Group

David M. Flannery
Gale Lea Rubrecht
Jackson Kelly PLLC
500 Lee Street East, Suite 1600
PO Box 553
Charleston, WV 25322-0553
(304) 340-1000
dmflannery@jacksonkelly.com

Counsel for Petitioner Midwest Ozone Group

Maureen N. Harbourt
Kean Miller LLP
PO Box 3513
Baton Rouge, LA 70821
(225) 387-0999
maureen.harbourt@keanmiller.com

Tokesha M. Collins
Kean Miller LLP
400 Convention Street
Suite 700
Baton Rouge, LA 70816
(225) 382-3426
tokesha.collins@keanmiller.com

Counsel for Petitioners Lafayette Utilities System and Louisiana Chemical Association

William F. Lane
Kilpatrick Townsend & Stockton LLP
4208 Six Forks Road
Suite 1400
Raleigh, NC 27609
(919) 420-1700
blane@kilpatricktownsend.com

Counsel for Petitioner CPI USA North Carolina LLC

Bart E. Cassidy
Katherine L. Vaccaro
Diana A. Silva
Manko, Gold, Katcher & Fox, LLP
401 City Avenue
Suite 500
Bala Cynwyd, PA 19004
(484) 430-5700
bcassidy@mgkflaw.com

Counsel for Petitioners ARIPPA and Sunbury Generation LP

Jordan Hemaidan
Todd Palmer
Michael Best & Freidrich LLP
One South Pinckney Street
Suite 700
Madison, WI 53705
(608) 283-4431
jjhemaidan@michaelbest.com

Counsel for Petitioners Midwest Food Processors Association, Wisconsin Cast Metals Association, Wisconsin Manufacturers and Commerce, and Wisconsin Paper Council, Inc.

Douglas E. Cloud
David Meezan
Christopher Max Zygmont
Mowrey Meezan Coddington Cloud LLP
1100 Peachtree Street
Suite 650
Atlanta, GA 30309
(404) 969-0740
doug.cloud@m2c2law.com

Counsel for Petitioner Municipal Electric Authority of Georgia

Gary M. Broadbent
Murray Energy Corp.
56854 Pleasant Ridge Road
Allendonia, OH 43902
(740) 926-1351
gbroadbent@coalsource.com

Michael O. McKown, General Counsel
Murray Energy Corp.
29325 Chagrin Blvd, Suite 300
Pepper Pike, OH 44122
(216) 765-1240
mmckown@coalsource.com

Counsel for Petitioners American Coal Co., American Energy Corp., Kenamerican Resources, Inc., Murray Energy Corp., Ohio American Energy, Inc., Ohio Valley Coal Co., and UtahAmerican Energy, Inc

Matthew J. Splitek
Donald K. Schott
Quarles & Brady LLP
33 East Main Street, Suite 900
Madison, WI 53703-3095
(608) 283-2454
matthew.splitek@quarles.com

Cynthia A. Faur
Quarles & Brady LLP
300 N. LaSalle Street, Suite 4000
Chicago, IL 60654-3406
(312) 715-5228

Counsel for Petitioner Wisconsin Electric Power Co.

Terry Russell Yellig
Sherman, Dunn, Cohen, Leifer & Yellig, PC
900 7th Street, NW
Suite 1000
Washington, DC 20001
(202) 785-9300
yellig@shermandunn.com

Counsel for Petitioner International Brotherhood of Electrical Workers, AFL-CIO

Dennis Lane
Stinson Morrison Hecker, LLP
1775 Pennsylvania Avenue, NW
Suite 800
Washington, DC 20006
(202) 785-9100
dlane@stinson.com

Counsel for Petitioners Kansas City Board of Public Utilities, Unified Government of Wyandotte County, Kansas City, Kansas, Kansas Gas and Electric Co., Sunflower Electric Power Corp., and Westar Energy, Inc.

Margaret Claiborne Campbell
Byron W. Kirkpatrick
Hahnah Williams
Troutman Sanders LLP
600 Peachtree Street, NE
5200 Bank of America Plaza
Atlanta, GA 30308-2216
(404) 885-3000
margaret.campbell@troutmansanders.com

Counsel for Petitioners Georgia Power Co., Southern Co. Services, Inc., and Southern Power Co.

Karl R. Moor
Julia A. Bailey Dulan
Southern Company Services, Inc.
600 North 18th Street
Bin 15N-8190
Birmingham, AL 35203
(205) 251-6227
krmoor@southernco.com

Counsel for Petitioner Southern Co. Services, Inc.

Peter S. Glaser
Tameka M. Collier
Troutman Sanders LLP
401 9th Street, NW, Suite 1000
Washington, DC 20004-2134
((202) 274-2950
peter.glaser@troutmansanders.com

Counsel for Petitioners National Mining Association and Peabody Energy Corp.

Grant F. Crandall
Arthur Traynor, III
United Mine Workers of America
18354 Quantico Gateway Drive
Suite 200
Triangle, VA 22172
(703) 291-2429
gcrandall@umwa.org

Eugene M. Trisko
Law Offices of Eugene M. Trisko
PO Box 47
Glenwood, MD 21738
(301) 639-5238
emtrisko7@gmail.com

Counsel for Petitioner United Mine Workers of America

Elizabeth P. Papez
John M. Holloway III
Elizabeth C. Williamson
Winston & Strawn, LLP
1700 K Street, NW
Washington, DC 20006-3817
(202) 282-5000
epapex@winston.com

Counsel for Petitioner East Kentucky Power Cooperative, Inc.

Jeffrey L. Landsman
Vincent M. Mele
Wheeler, Van Sickle & Anderson, S.C.
25 West Main Street
Suite 801
Madison, WI 53703-3398
(608) 255-7277
jlandsman@wheelerlaw.com

Counsel for Petitioner Dairyland Power Cooperative

Ann M. Seha
Assistant General Counsel
XCEL ENERGY INC.
414 Nicollet Mall
5th Floor
Minneapolis, MN 55401
(612) 215-4582
ann.m.seha@xcelenergy.com

Counsel for Petitioners Northern States Power Co. – Minnesota, and Southwestern Public Service Co.

CERTIFICATE AS TO PARTIES, RULINGS, AND RELATED CASES

The following information is provided pursuant to D.C. Circuit Rule 28(a)(1):

(A) Parties and *Amici*

Petitioners

Industry and Labor Petitioners

AEP Texas North Co.
Alabama Power Co.
American Coal Co.
American Energy Corp.
Appalachian Power Co.
ARIPPA
Big Brown Lignite Company LLC
Big Brown Power Company LLC
Columbus Southern Power Co.
Consolidated Edison Company of New York, Inc.
CPI USA North Carolina LLC
Dairyland Power Cooperative
DTE Stoneman, LLC
East Kentucky Power Cooperative, Inc.
EME Homer City Generation, LP.
Entergy Corp.
Environmental Committee of the Florida Electric Power Coordinating Group, Inc.
Environmental Energy Alliance of New York, LLC
GenOn Energy, Inc.
Georgia Power Co.
Gulf Power Co.
Indiana Michigan Power Co.
International Brotherhood of Electrical Workers, AFL-CIO
Kansas City Board of Public Utilities, Unified Government of Wyandotte County, Kansas City, Kansas
Kansas Gas and Electric Co.
Kenamerican Resources, Inc.
Kentucky Power Co.
Lafayette Utilities System
Louisiana Chemical Association
Luminant Big Brown Mining Company LLC
Luminant Energy Company LLC
Luminant Generation Company LLC
Luminant Holding Company LLC
Luminant Mining Company LLC
Midwest Food Processors Association
Midwest Ozone Group
Mississippi Power Co.
Municipal Electric Authority of Georgia
Murray Energy Corp.
National Mining Association
National Rural Electric Cooperative Association
Northern States Power Co. (a Minnesota corporation)
Oak Grove Management Company LLC
Ohio Power Co.
Ohio Valley Coal Co.
OhioAmerican Energy, Inc.

Peabody Energy Corp.
Public Service Company of Oklahoma
Sandow Power Company LLC
South Mississippi Electric Power Ass'n
Southern Company Services, Inc.
Southern Power Co.
Southwestern Electric Power Co.
Southwestern Public Service Co.
Sunbury Generation LP
Sunflower Electric Power Corp.
Utility Air Regulatory Group
United Mine Workers of America
UtahAmerican Energy, Inc.
Westar Energy, Inc.
Western Farmers Electric Cooperative
Wisconsin Cast Metals Association
Wisconsin Electric Power Co.
Wisconsin Paper Council, Inc.
Wisconsin Manufacturers and Commerce
Wisconsin Public Service Corp.

State and Municipal Petitioners

City of Ames, Iowa
City of Springfield, Illinois, Office of Public Utilities, doing business as City Water, Light & Power
Louisiana Department of Environmental Quality
Louisiana Public Service Commission
Mississippi Public Service Commission
Public Utility Commission of Texas
Railroad Commission of Texas
State of Alabama
State of Florida
State of Georgia
State of Indiana
State of Kansas
State of Louisiana
State of Michigan
State of Nebraska
State of Ohio
State of Oklahoma
State of South Carolina
State of Texas
State of Virginia
State of Wisconsin
Texas Commission on Environmental Quality
Texas General Land Office

Intervenors in Support of Petitioners

San Miguel Electric Cooperative
City of New York (Nos. 11-1388 and 11-1395 only)
State of New York (Nos. 11-1388 and 11-1395 only)

Respondents

United States Environmental Protection Agency ("EPA")
Lisa P. Jackson, Administrator.

Intervenors in Support of Respondent

Industry and Labor Intervenors

American Lung Association
Calpine Corporation
Clean Air Council
Environmental Defense Fund
Exelon Corporation
Natural Resources Defense Council
Public Service Enterprise Group, Inc.
Sierra Club

State and Municipal Intervenors

City of Bridgeport, Connecticut
City of Chicago
City of New York (all but Nos. 11-1388 and 11-1395)
City of Philadelphia
Mayor and City Council of Baltimore
State of Connecticut
State of Delaware
District of Columbia
State of Illinois
State of Maryland
Commonwealth of Massachusetts
State of New York (all but Nos. 11-1388 and 1395)
State of North Carolina
State of Rhode Island
State of Vermont

Amici

Putnam County, Georgia
Industrial Energy Consumers of America
Southern Legal Foundation, Inc.

(B) Rulings Under Review

These petitions challenge EPA's final rule, "Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals," 76 FR 48208 (Aug. 8, 2011).

(C) Related Cases

Each of the petitions for review consolidated under No. 11-1302 is related. These cases consist of Case Nos. 11-1315, 11-1323, 11-1329, 11-1338, 11-1340, 11-

1350, 11-1357, 11-1358, 11-1359, 11-1360, 11-1361, 11-1362, 11-1363, 11-1364, 11-1365, 11-1366, 11-1367, 11-1368, 11-1369, 11-1371, 11-1372, 11-1373, 11-1374, 11-1375, 11-1376, 11-1377, 11-1378, 11-1379, 11-1380, 11-1381, 11-1382, 11-1383, 11-1384, 11-1385, 11-1386, 11-1387, 11-1388, 11-1389, 11-1390, 11-1391, 11-1392, 11-1393, 11-1394 and 11-1395. The consolidated cases on review have not previously been reviewed by this Court or any other court. There are several other cases addressing similar issues or related rules. On January 10, 2011, this Court severed and consolidated two challenges, in 11-1329 and 11-1333, to EPA's "Approval and Promulgation of Air Quality Implementation Plan; Kansas; Final Disapproval of Interstate Transport State Implementation Plan Revision for the 2006 24-hour PM2.5 NAAQS," 76 FR 43143 (July 20, 2011). The Court assigned them a separate docket number, 12-1019, and ordered them held in abeyance pending decision here. A challenge in 11-1358 to certain electronic data requirements in CSAPR as well as a challenge in 11-1427 to EPA's "Approval and Promulgation of Air Quality Implementation Plan; Georgia; Disapproval of Interstate Transport Submission for the 2006 24-Hour PM[2.5] Standards," 76 FR 43159 (July 20,2011) were also held in abeyance. Finally, two challenges were filed in 12-1023 and 12-1026 to EPA's supplemental final rule, "Federal Implementation Plans for Iowa, Michigan, Missouri, Oklahoma, and Wisconsin and Determination for Kansas Regarding Interstate Transport of Ozone," 76 FR 80760 (Dec. 27, 2011), and they have been consolidated.

RULE 26.1 DISCLOSURE STATEMENT

Pursuant to Federal Rule of Appellate Procedure 26.1 and D.C. Circuit Rule 26.1, the Industry and Labor Petitioners provide the following corporate disclosures:

AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma, and Southwestern Electric Power Company state as follows: AEP Texas North Company is a wholly-owned subsidiary of AEP Utilities, Inc., which is a wholly-owned subsidiary of American Electric Power Company, Inc. All other Petitioners are direct subsidiaries of American Electric Power Company, Inc. American Electric Power Company, Inc. is the only publicly held corporation that owns 10% of more of any of the Petitioners' stock. Each of the Petitioners is the owner and/or operator of one or more of the electric generating units that will be subject to the requirements of the final rule at issue in the Petition for Review in this matter.

The American Coal Company, a Delaware corporation, is a wholly owned subsidiary of AmCoal Holdings, Inc., an Ohio corporation, which is a wholly owned subsidiary of the Murray Energy Corporation, whose complete corporate disclosure statement appears below. The American Coal Company owns and operates the New Era Mine and the New Future Mine in Saline County, Illinois.

American Energy Corporation, an Ohio corporation, is a wholly owned subsidiary of Murray Energy Corporation, whose complete corporate disclosure appears below. American Energy Corporation owns and operates the Century Mine in Monroe County, Ohio.

ARIPPA is a non-profit trade association that represents a membership primarily comprised of electric generating plants using environmentally-friendly circulating fluidized bed (CFB) boiler technology to convert coal refuse and/or other alternative fuels such as biomass into alternative energy and/or steam, with the resultant alkaline ash used to reclaim mine lands. ARIPPA was organized in 1988 for the purpose of promoting the professional, legislative and technical interests of its member facilities. ARIPPA has no outstanding shares or debt securities in the hands of the public and does not have any parent, subsidiary, or affiliate that has issued shares or debt securities to the public.

Big Brown Lignite Company LLC, a Texas limited liability company, is the legal entity that owns the lignite reserves associated with the Big Brown generation facility. Big Brown Lignite Company LLC is a wholly owned subsidiary of Luminant Holding Company LLC, whose complete corporate disclosure statement appears below.

Big Brown Power Company LLC, a Texas limited liability company, is the legal entity that owns the lignite/coal-fueled Big Brown generation facility. Big Brown Power Company LLC is a wholly owned subsidiary of Luminant Holding Company LLC, whose complete corporate disclosure statement appears below.

Consolidated Edison Company of New York, Inc. ("Con Edison") is a regulated utility that provides electric service in New York City and Westchester County and steam service in Manhattan. Consolidated Edison, Inc. is the parent company of Con Edison and owns 100 percent of Con Edison's common stock. No other publicly held company has a 10 percent or greater ownership interest in Con Edison, although Con Edison also has preferred stock outstanding.

CPI USA North Carolina LLC ("CPI NC") is a Delaware limited liability company whose sole member is Capital Power (NC Holdings) LLC, a Delaware limited liability company. CPI NC is an indirect wholly owned subsidiary of Capital Power L.P., an Ontario limited partnership ("CPLP"). A majority of the limited partnership interests and one hundred percent of the general partnership interests in CPLP are indirectly owned by Capital Power Corporation, a Canadian Federal corporation whose stock is traded on the Toronto Stock Exchange. CPI NC owns two electric generating facilities located in Roxboro, North Carolina and Southport, North Carolina.

Dairyland Power Cooperative ("Dairyland") is a non-stock cooperative association organized under the laws of the State of Wisconsin, with its principal office located in La Crosse, Wisconsin. Dairyland is engaged, among other things, in the business of generating and transmitting electric power to its 25 member distribution cooperatives and to other wholesale customers. Dairyland has no corporate parent. No publicly held corporations have a 10% or greater ownership interest in Dairyland.

DTE Stoneman, LLC is a wholly owned subsidiary of DTE Energy Resources, Inc., which in turn is wholly owned by DTE Energy, Inc. DTE Energy, Inc. has no parent company, and no publicly-held company has a 10% or greater ownership interest in DTE Energy, Inc. DTE Stoneman LLC owns and operates the E.J. Stoneman Generating Station, a merchant biomass-fired electric generating facility located in Cassville, Wisconsin.

East Kentucky Power Cooperative, Inc. is a not-for-profit generation and transmission electric utility cooperative headquartered in Winchester, Kentucky. East Kentucky Power Cooperative, Inc. is owned, operated and governed by its members who use the energy and services it provides. There is no publically held corporation that owns 10% or more of East Kentucky Power Cooperative's stock. East Kentucky Power Cooperative, Inc. is not owned in whole or part by a parent company.

EME Homer City Generation, LP is a limited partnership composed of Mission Energy Westside, Inc., a California corporation, as the general partner and Chestnut Ridge Energy Company, a California corporation, as the limited partner. Mission Energy Westside, Inc. and Chestnut Ridge Energy Company are wholly-owned subsidiaries of Edison Mission Holdings Company, which, in turn, is a wholly-owned subsidiary of Edison Mission Energy. Edison Mission Energy is a Delaware Corporation, which is a wholly-owned subsidiary of Mission Energy Holdings Company, a Delaware corporation, which, in turn, is a wholly-owned subsidiary of Edison Mission Group, Inc., a Delaware corporation, which, in turn, is a wholly-owned subsidiary of Edison International, a California Corporation. EME Homer City Generation, L.P. owns and operates three coal-fired electric generating units and related facilities in Pennsylvania. Edison Mission Energy is an independent power producer that generates electricity to sell wholesale in the open market. The ultimate parent company, Edison International, is engaged in the business of holding for investment the common stock of its subsidiaries which also include Southern California Edison, a California public utility corporation, and Edison Capital, which has investments in energy and infrastructure projects worldwide. In addition, the following parent companies, or affiliates of EME Homer City Generation, L.P. have outstanding shares that are in the hands of the public: Edison International and Southern California Edison.

Entergy Corporation is an integrated energy company engaged primarily in electric power production, transmission, and retail distribution operations. Entergy, through its subsidiaries, owns and operates power plants with approximately 30,000 megawatts of electric generating capacity and operates electric utility systems in four states – Louisiana, Arkansas, Mississippi, and Texas. Entergy Corporation is a publicly traded company and no publicly held company has a 10 percent or greater ownership interest in Entergy Corporation.

Environmental Committee of the Florida Electric Power Coordinating Group, Inc. represents the interests of its member utilities, which include investor-owned utilities, electric cooperatives and municipal utilities, on environmental issues that affect Florida's electric utility industry. The Florida Electric Power Coordinating Group, Inc. is a non-profit, non-governmental corporate entity organized under the laws of Florida. It does not have a parent corporation and no publicly held corporation owns ten percent or more of the Florida Electric Power Coordinating Group, Inc.'s stock.

Environmental Energy Alliance of New York, LLC ("EEANY") has no parent companies, and no publicly held corporation owns 10% or more of EEANY's stock. EEANY, which is a limited liability company organized under the laws of New York State, is a trade association of electric generating companies, transmission/ distribution companies, and other providers of energy services in the State of New York. EEANY's primary purpose is to support and enhance the efforts of its members in understanding and participating in environmental statutes, regulations, and policies.

GenOn Energy, Inc. ("GenOn") is a publicly held company that is one of the largest independent power producers in the United States and operates electric generating plants in 12 states. GenOn, through its subsidiaries, owns and operates generating plants with a total capacity of approximately 24,200 megawatts – enough electricity to serve about 25 million homes. The vast majority of this electric power is produced in plants that burn coal, natural gas and, to a lesser extent, oil.

International Brotherhood of Electrical Workers, AFL-CIO ("IBEW") is an unincorporated international labor organization with headquarters in Washington, District of Columbia. The IBEW has no parent companies, subsidiaries, or affiliates that issue shares or debt securities to the public. The IBEW provides collective bargaining representation and other service to its members, as well as collective bargaining representation to all members of collective bargaining units that it exclusively represents. The IBEW represents electrical workers in the United States, Canada, and the Republic of Panama, engaged in the manufacture, assembling, construction, installation, and erection, repair or maintenance of all materials, equipment, apparatus and appliances required in the production, generation, utilization and control of electricity and its effects, as well as transmission of data, voice, sound, video and other emerging technologies (including fiber optics, high speed data cable, etc.). The U.S. Environmental Protection Agency ("EPA") adopted a final rule entitled "Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals" that was published in the Federal Register on August 8, 2011 (76 FR 48208), which became effective on October 7, 2011. EPA's final rule is intended to limit the emissions of nitrogen oxides (NO_x) and sulfur dioxide (SO_2) in 27 states in the eastern United States. Some of the electrical workers represented by the IBEW are employed or otherwise engaged at electric generating units located in the 27 states in the eastern United States that will be affected by EPA's final rule.

Kansas City Board of Public Utilities—Unified Government of Wyandotte County/Kansas City, Kansas is a governmental entity organized under the laws of the state of Kansas and is therefore not required to provide a Corporate Disclosure Statement. Accordingly, none has been provided.

KenAmerican Resources, Inc., a Kentucky corporation, is a wholly owned subsidiary of Mill Creek Mining Company, a Pennsylvania corporation, which is a wholly owned subsidiary of Coal Resources, Inc., an Ohio corporation, which is a wholly owned subsidiary of Coal Resources Holdings Company, a Delaware corporation, which is a wholly owned subsidiary of Murray American Energy, Inc., a Wyoming corporation, which is a wholly owned subsidiary of Murray Energy Corporation, whose complete corporate disclosure statement appears below. KenAmerican Resources, Inc. owns and operates the Paradise #9 Mine in Muhlenberg County, Kentucky.

Lafayette Utilities System ("LUS"), a department within the Lafayette City-Parish Consolidated Government, is a local government utility primarily servicing the citizens of the City of Lafayette, Louisiana. As a customer-owned municipal utility, the Lafayette Utilities System's mission is to provide its customers with quality and affordable electric, water, wastewater and fiber optic services. The Lafayette Utilities System does not issue stock; it does not have a parent corporation, and no publicly held corporation holds any Lafayette Utilities System stock.

Louisiana Chemical Association has no parent companies, and no publicly-held company has a 10% or greater ownership interest. The Louisiana Chemical Association is a non-profit Louisiana corporation formed in 1959. Its mission is to promote a positive climate for chemical manufacturing that ensures long-term economic growth for its members. It is a "trade association" within the meaning of D.C. Circuit Rule 26.1

Luminant Big Brown Mining Company LLC, a Texas limited liability company, is the legal entity that owns the mine assets utilized in connection with the Big Brown generation facility. Luminant Big Brown Mining Company LLC is a wholly owned subsidiary of Luminant Holding Company LLC, whose complete corporate disclosure statement appears below.

Luminant Energy Company LLC, a Texas limited liability company, is the legal entity that conducts the wholesale energy sales and purchases and commodity risk management and trading activities for the Luminant Entities. Luminant Energy Company LLC is a wholly owned subsidiary of Luminant Holding Company LLC, whose complete corporate disclosure statement appears below.

Luminant Generation Company LLC, a Texas limited liability company, is the legal entity that owns numerous Luminant generation assets, including the Monticello, Martin Lake, Sandow Unit 4 and Comanche Peak generation facilities and a number of additional generation facilities and assets associated with the Luminant Entities' competitive power generation business in the state of Texas. Luminant Generation Company LLC is a wholly owned subsidiary of Luminant Holding Company LLC, whose complete corporate disclosure statement appears below.

Luminant Holding Company LLC is the parent company that wholly owns Luminant Generation Company LLC, Sandow Power Company LLC, Big Brown Power Company LLC, Oak Grove Management Company LLC, Luminant Mining Company LLC, Big Brown Lignite Company LLC, Luminant Big Brown Mining Company LLC, and Luminant Energy Company LLC (collectively, the "Luminant Entities"). Luminant Holding Company LLC is a Delaware LLC and is a wholly-owned subsidiary of Texas Competitive Electric Holdings Company LLC ("TCEH"). TCEH is a holding company for subsidiaries engaged in competitive electricity market activities largely in Texas including electricity generation, wholesale energy sales and purchases, commodity risk management and trading activities, and retail electricity sales. TCEH owns or leases more than 15,000 megawatts of generation capacity in Texas, which consists of lignite/coal, nuclear and natural gas-fueled generation facilities. In addition, TCEH is the largest purchaser of wind-generated electricity in Texas and the fifth largest in the United States. TCEH provides competitive electricity and related services to approximately two million retail electricity customers in Texas. TCEH is a wholly-owned subsidiary of Energy Future Competitive Holdings Company ("EFCH"). EFCH is a wholly-owned subsidiary of Energy Future Holdings Corp. ("EFH Corp."), formerly TXU Corp., and is a Dallas, Texas-based holding company that conducts its operations almost entirely through TCEH. EFH Corp. is a Dallas, Texas-based holding company with a portfolio of competitive and regulated energy businesses in Texas that conducts its operations principally through its subsidiaries TCEH and Oncor Electric Delivery Company LLC. Substantially all of the common stock of EFH Corp is owned by Texas Energy Future Holdings Limited Partnership, which is a privately held limited partnership. No publicly-held entities have a 10% or greater ownership interest in EFH Corp.

Luminant Mining Company LLC, a Texas limited liability company, is the legal entity that owns the mine assets utilized in connection with the Monticello and Martin Lake generation facilities as well as certain mine assets utilized in connection with the Sandow generation facilities. Luminant Mining Company LLC is a wholly owned subsidiary of Luminant Holding Company LLC, whose complete corporate disclosure statement appears above.

Midwest Food Processors Association ("MWFPA") is a non profit trade association representing the food processing industry in the Midwest. Its members operate over 100 facilities in Wisconsin, Illinois, and Minnesota. In 2008, the industry generated nearly $34 billion in product shipments and employed more than 62,000 people in Wisconsin. MWFPA advocates regulatory and legislative positions that are of importance to the food processing industry, including the collection, treatment, reclamation and disposal of wastewater. MWFPA and its members have represented the industry on various advisory bodies at the state level, as well as before the Legislature, the Wisconsin Department of Natural Resources and other executive branch agencies, the EPA, and the Courts. MWFPA works with state legislators on a continuing basis to ensure new regulations do not unduly limit the ability of Wisconsin's food processors to continue operating and expanding in Wisconsin. MWFPA has no parent company, and no publicly held company has a 10% or greater ownership in the entity.

Midwest Ozone Group is an unincorporated association of businesses and organizations formed to assist in the development of scientifically sound and effective ozone strategies. Because the Midwest Ozone Group is a continuing association of numerous businesses and organizations operated for the purpose of promoting the general commercial and legislative interests of its membership, no listing of its members that have issued shares or debt securities to the public is required under Circuit Rule 26.1(b).

Municipal Electric Authority of Georgia ("MEAG") is an instrumentality of the State of Georgia, created as a public corporation by the Georgia General Assembly. *See* O.C.G.A. §§46-3-110 to -115. The statutory purpose of MEAG is to provide an adequate, dependable, and economical wholesale supply of electricity to those political subdivisions of Georgia that owned and operated electric distribution systems on March 18, 1975, and elected to contract with the Authority for the purchase of wholesale power. *See id.* § 46-3-125. MEAG does not issue stock; it does not have a parent corporation, and no publicly held corporation holds any MEAG stock.

Murray Energy Corporation, an Ohio corporation, is the legal entity that owns several bituminous coal producing assets and is the parent company of American Energy Corporation, Ohio Valley Resources, Inc., OhioAmerican Energy, Incorporated, AmCoal Holdings, Inc., Murray American Energy, Inc., and UtahAmerican Energy, Inc. Murray Energy Corporation is a wholly owned subsidiary of Murray Energy Holdings Company, a Delaware corporation. All shares of Murray Energy Holdings Company are held by the Robert E. Murray Family Trust with Mr.

Robert E. Murray as Trustee. No publicly held entities have a 10% or greater interest in Murray Energy Corporation or any of its subsidiary companies.

National Mining Association ("NMA") is a non-profit, incorporated national trade association whose members include the producers of most of America's coal, metals, and industrial and agricultural minerals; manufacturers of mining and mineral processing machinery, equipment, and supplies; and engineering and consulting firms that serve the mining industry. NMA has no parent companies, subsidiaries, or affiliates that have issued shares or debt securities to the public, although NMA's individual members may have done so.

National Rural Electric Cooperative Association ("NRECA") is the national association of rural electric cooperatives. NRECA does not have a parent corporation, and no publicly held corporation owns 10 percent or more of its stock.

Northern States Power Company—Minnesota is a wholly owned subsidiary of Xcel Energy Inc. Xcel Energy Inc. is a registered, public utility holding company that is incorporated under the laws of the State of Minnesota. No other publicly held company holds a 10 percent or greater ownership interest in Northern States Power Company – Minnesota.

Oak Grove Management Company LLC, a Delaware limited liability company, is the legal entity that owns the facility and related assets associated with Oak Grove Units 1 and 2, new lignite-fueled generation units near Robertson County, Texas. Oak Grove Management Company LLC is a wholly owned subsidiary of Luminant Holding Company LLC, whose complete corporate disclosure statement appears above.

OhioAmerican Energy, Incorporated, an Ohio corporation, is a wholly owned subsidiary of Murray Energy Corporation, whose complete corporate disclosure statement appears above. OhioAmerican Energy, Incorporated owns and operates the Salt Run Mine #1 in Jefferson County, Ohio.

The Ohio Valley Coal Company, an Ohio corporation, is a wholly owned subsidiary of Ohio Valley Resources, Inc., an Ohio corporation, which is a wholly owned subsidiary of the Murray Energy Corporation, whose complete corporate disclosure statement appears above. The Ohio Valley Coal Company owns and operates the Powhatan No. 6 Mine in Belmont County, Ohio.

Peabody Energy Corporation ("Peabody") certifies that it is a publicly-traded company and, to its knowledge, has no shareholder owning ten percent or more of its common stock with the exception of BlackRock, Inc. and T. Rowe Price Group, Inc., which respectively own approximately 10.7% and 10.4% of Peabody's outstanding common stock. Peabody's principal business is the mining and sale of coal.

Sandow Power Company LLC, a Texas limited liability company, is the legal entity that owns the Sandow Unit 5 facility, a new lignite-fueled generation unit located in Rockdale, Texas, and related assets. Sandow Power Company LLC is a wholly owned subsidiary of Luminant Holding Company LLC, whose complete corporate disclosure statement appears above.

South Mississippi Electric Power Association ("SMEPA") is a non-profit electric cooperative that provides generation and transmission service to its eleven member distribution cooperatives located throughout rural Mississippi. SMEPA operates a generation and transmission system that serves as a NERC Balancing Authority and is interconnected with four neighboring utilities through six transmission interconnections. SMEPA has no parent corporation nor does any publicly held corporation own ten percent (10%) or more of its stock.

Southern Company Services, Inc., Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company are all wholly-owned subsidiaries of Southern Company, which is a publicly-held corporation. Other than Southern Company, no publicly-held company owns 10% or more of any of these Petitioners' stock. No publicly-held company holds 10% or more of Southern Company's stock. Southern Company stock is traded publicly on the New York Stock Exchange under the symbol "SO." Through its subsidiaries, Southern Company is a leading U.S. producer of electricity, generating and delivering electricity to over four million customers in the southeastern United States. Southern Company subsidiaries include four vertically integrated electric utilities – Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company – as well as Southern Power Company, which owns generation assets and sells electricity at market-based rates in the wholesale market. These subsidiaries, each a Petitioner here, operate more than 42,000 megawatts of coal, natural gas, oil, nuclear, and hydroelectric generating capacity. Southern Company Services, Inc. is the services company for Southern Company and its operating subsidiaries. Southern Company Services, Inc. provides, among other things, engineering and other technical support for the operating companies.

Southwestern Public Service Company is a wholly owned subsidiary of Xcel Energy Inc. Xcel Energy Inc. is a registered, public utility holding company that is incorporated under the laws of the State of Minnesota. No other publicly held company holds a 10 percent or greater ownership interest in Southwestern Public Service Company.

Sunbury Generation LP ("Sunbury") is a limited partnership composed of the following members: DALK Land LP, JAZ Ventures, LP, AMCIC Sunbury AIV, LP, and First Reserve Fund XI, L.P. Corona Power LLC is a general partner in Sunbury. Corona Power LLC is composed of the following members: DALK Land LP, JAZ Ventures, LP, AMCIC Sunbury AIV, LP, and first Reserve Fund XI, L.P. Sunbury owns and operates an electric generating facility in Shamokin Dam, Snyder County, Pennsylvania. Sunbury operates several coal-fired boilers and combustion turbines at its facility to support its electricity generation operations.

Sunflower Electric Power Corporation is a Kansas non-profit corporation doing business as a cooperative with its principal place of business in Hays, Kansas. It is not a publicly held corporation; no publicly held corporation holds any ownership interest in it and it has no "parent" corporation. It is owned solely by its seven member distribution cooperatives, all of which are located in western Kansas. Sunflower Electric Power Corporation is engaged in the generation, transmission and sale of electric power and energy at wholesale to its member distribution cooperatives and municipalities in the state of Kansas.

United Mine Workers of America ("UMWA") is a non-profit national labor organization with headquarters in Triangle, Virginia. UMWA's members are active and retired miners engaged in the extraction of coal and other minerals in the United States and Canada, and workers in other industries in the United States organized by the UMWA. UMWA provides collective bargaining representation and other membership services on behalf of its members. UMWA is affiliated with the American Federation of Labor-Congress of Industrial Organizations. UMWA has no parent companies, subsidiaries, or affiliates that have issued shares or debt securities to the public.

UtahAmerican Energy, Inc., a Utah corporation, owns and operates the Lila Canyon Mine in Carbon County, Utah. UtahAmerican Energy, Inc. is a wholly owned subsidiary of Murray Energy Corporation, whose complete corporate disclosure statement appears above. UtahAmerican Energy, Inc. is the parent company of Andalex Resources, Inc., a Delaware corporation, which is the parent company of West Ridge Resources, Inc., a Utah corporation, which owns and operates the West Ridge Mine in Carbon County, Utah.

Utility Air Regulatory Group ("UARG") is a not-for-profit association of individual electric generating companies and national trade associations that participates on behalf of its members collectively in administrative proceedings under the Clean Air Act, and in litigation arising from those proceedings, that affect electric generators. UARG has no outstanding shares or debt securities in the hands of the public and has no parent company. No publicly held company has a 10% or greater ownership interest in UARG.

Westar Energy, Inc. is a publicly-traded Kansas corporation with its principal place of business in Topeka, Kansas, and is the parent corporation of Kansas Gas and Electric Company ("KGE"), a Kansas corporation with its principal place of business in Topeka, Kansas. Westar and its wholly owned subsidiary, KGE, are electric utilities engaged in the generation, transmission, distribution and sale of electric power and energy at wholesale and retail to approximately 687,000 customers in the state of Kansas. Westar owns all of the stock of KGE. In addition to Westar's publicly traded stock, both Westar and KGE have issued debt and bonds to the public. There is no corporation that owns 10% or more of the stock of Westar Energy, Inc.

Western Farmers Electric Cooperative ("WFEC") is a non-profit generation and transmission rural electric cooperative that supplies wholesale electricity to its member owners, which include 19 rural electric distribution cooperatives located in Oklahoma and 4 distribution cooperatives located in New Mexico. No publicly-held company has a 10 percent or greater ownership interest in WFEC.

Wisconsin Cast Metals Association ("WCMA") is a trade association dedicated to enhancing the knowledge and competitiveness of metalcasting in the state of Wisconsin through the collective actions of its members. Wisconsin metal casting is a $3 billion industry consisting of some 130 foundries employing approximately 18,000 people in communities across the state. Wisconsin metalcasting products support other primary manufacturing located within the state, that in-turn provide jobs and supply product to service a wide variety of industries including mining, construction, transportation, consumer products, energy and military applications. WCMA has no parent companies, and no publicly held company has a 10% or greater ownership in the entity.

Wisconsin Electric Power Company (d/b/a "We Energies") is a wholly-owned subsidiary of Wisconsin Energy Corporation, a publicly-traded company. Wisconsin Electric Power Company is a regulated electric utility, and its operations are affected by CSAPR.

Wisconsin Paper Council, Inc. ("WPC") is a non profit corporation and operates as a trade association representing the interests of Wisconsin's pulp and paper manufacturers, and allied industries. WPC is a membership organization and represents the interests of 20 pulp and paper manufacturers plus allied industries in SIC Code 26. These industries employ approximately 32,000 Wisconsin residents in good paying jobs. WPC represents its members on matters of mutual concern before the Legislature, the Wisconsin Department of Natural Resources and other executive branch agencies, the EPA, and the Courts. Since the early 1970s, WPC and its members have taken an active role in advocating policies for Wisconsin which protect the environment while allowing Wisconsin's paper manufacutrers to operate efficiently and competitively with their peers in other states. WPC has no parent company, and no publicly held company has a 10% or greater ownership in the entity.

Wisconsin Public Service Corporation ("WPSC") is a wholly owned subsidiary of the publically owned corporation Integrys Energy Group, Inc (NYSE: TEG). WPSC is a regulated electric and natural gas utility operating in northeast and central Wisconsin and an adjacent portion of Upper Michigan, covering an 11,000 square mile service area. As of December 31, 2010, WPSC had 1,363 employees and served approximately 439,000 electric customers, the vast majority of which are in Wisconsin. WPSC owns and operates numerous coal and gas-fired electric generating units ("EGUs"), with a total electric generating capacity based on summer capacity ratings of over 2000 megawatts, including the utility's share of jointly owned facilities. EGUs owned and operated by WPSC will be directly and adversely affected by the final rule for which WPSC seeks review.

Wisconsin Manufacturers and Commerce ("WMC") is a business trade association with nearly 4,000 members and is dedicated to making Wisconsin the most competitive state in the nation to do business through public policy that supports a healthy business climate. Its members are Wisconsin businesses that operate throughout the state in the manufacturing, energy, commercial, health care, insurance, banking, and service industry sectors of the economy. Roughly one-fourth of Wisconsin's workforce is employed by a WMC member company. WMC has no parent company, and no publicly held company has a 10% or greater ownership in the entity.

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GLOSSARY

CAA	Clean Air Act
CAMx	Comprehensive Air Quality Model with Extensions
CAIR	Clean Air Interstate Rule
CSAPR	Cross State Air Pollution Rule
EGU	Electric Generating Unit
EPA	United States Environmental Protection Agency
FIP	Federal Implementation Plan
IPM	Integrated Planning Model
LNB	Low-NO_X Burner
NAAQS	National Ambient Air Quality Standards
NO_X	Nitrogen Oxides
NSPS	New Source Performance Standards
$PM_{2.5}$	Fine Particulate Matter
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SNCR	Selective Noncatalytic Reduction

JURISDICTIONAL STATEMENT

EPA published its final rule, "Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals," at 76 FR 48208, on August 8, 2011 (CSAPR). The consolidated petitions for review were timely, and this Court has jurisdiction under 42 U.S.C. §7607(b)(1).

STATEMENT OF ISSUES

1. Whether EPA contravened §110(a)(2)(D)(i)(I) of the Clean Air Act (CAA) and this Court's decision in *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008), by setting emissions budgets without regard to an upwind State's "significant contribution" to any downwind State's failure to meet EPA's national air quality standards.

2. Whether EPA contravened §110(a)(2)(D)(i)(I) by imposing emission reductions on upwind States beyond those necessary for the downwind States to attain or maintain EPA's national air quality standards.

3. Whether EPA's application of its "significant contribution" methodology was arbitrary, capricious, or otherwise unlawful.

4. Whether EPA's inclusion of States in CSAPR based on erroneous modeled projections of future air quality and in disregard of available real-world data is arbitrary, capricious, or otherwise unlawful.

5. Whether EPA's reliance on flawed Integrated Planning Model (IPM) methodologies to set emission budgets is arbitrary, capricious, or otherwise unlawful.

6. Whether EPA's unprecedented and extraordinarily truncated compliance deadlines are arbitrary, capricious, or otherwise unlawful.

STATUTES AND REGULATIONS

42 U.S.C. §§7407, 7408(a)(1)(A), 7409, 7410, 7502, 7607, and relevant regulations are reproduced in the attached Statutory Addendum.

INTRODUCTION

This proceeding challenges one of the most costly, burdensome, and arbitrary rules ever issued by EPA under the CAA. The rule at issue—CSAPR—regulates the interstate transport of certain air pollutants by imposing emission budgets on States subject to the rule. This Court held that EPA's prior attempt to regulate such interstate transport in the Clean Air Interstate Rule (CAIR) exceeded the agency's authority under the CAA, 42 U.S.C. §§7401 *et seq*. *See North Carolina v. EPA*, 531 F.3d 896, *modified on reh'g*, 550 F.3d 1176 (D.C. Cir. 2008). CSAPR suffers from similar, if not more egregious, legal flaws.

The CAA gives each State the "primary responsibility" for ensuring that national ambient air quality standards (NAAQS) are satisfied within that State. 42 U.S.C. §7407(a). The CAA also contains a limited interstate transport provision that may require one State to reduce pollutants that are transported to another, "downwind," State. *Id.* §7410(a)(2)(D)(i)(I). As EPA itself has recognized, however, that provision authorizes only "the elimination of emissions that *significantly contribute* to nonattainment or interfere with maintenance of the NAAQS in other states; it does not shift to upwind states the responsibility for ensuring that all areas in other states attain the NAAQS." 76 FR at 48210 (emphasis added).

Like the CAIR rule that this Court held was unlawful in *North Carolina*, CSAPR fails to "track the requirements of section 110(a)(2)(D)(i)(I)" by ignoring each State's "significant contribution"—or lack thereof—to nonattainment in a downwind State. 531 F.3d at 917. Although EPA excluded States from CSAPR based on air quality thresholds below which it agreed a State "do[es] not significantly contribute to nonattainment or interfere with maintenance of the relevant NAAQS," 76 FR at 48237, it then ignored altogether the magnitude of the remaining States' contributions when it came to setting emissions budgets. Instead, EPA purported to limit emissions based on its view of what constitute "reasonable" and "cost-effective" emission controls on a region-wide basis. *See, e.g.*, *id.* at 48248-49, 48257. Because that approach finds no support in the text of the statute and exceeds EPA's authority as recognized in *North Carolina*, CSAPR must be vacated.

EPA compounded that fundamental error by ignoring §110(a)(2)(D)(i)(I)'s other critical limitation: EPA may require only that a State eliminate "amounts" of emissions that actually "contribute significantly to *nonattainment in, or interfere with maintenance by*," a downwind State "with respect" to a relevant NAAQS. (Emphasis added.) Instead, based on its views of "reasonable" and "cost-effective" emissions controls, EPA imposed emission reduction requirements for some States that are *far more* stringent than necessary for downwind States to achieve or maintain the

NAAQS. That aspect of the rule, too, exceeds EPA's authority under §110(a)(2)(D)(i)(I).

But even if EPA had statutory authority to require upwind States to adopt "reasonable" emissions budgets entirely unrelated to any significant contribution to downwind States' nonattainment, the methodology it used to determine those budgets was arbitrary. EPA refused to consider real-world air quality data contradicting its own implausible air quality projections that were the basis for subjecting upwind states to CSAPR. And where its own methodology would have resulted in less restrictive emissions budgets, EPA simply made an *ad hoc* adjustment to reach its pre-determined preferred (more onerous) limit. EPA then set unprecedented, truncated compliance deadlines that assumed that industry should have begun installation of costly controls even before the final rule had issued.

EPA has ample means lawfully to address interstate transport subject to the CAA. That includes setting emissions budgets based on each State's "significant contribution" to downwind nonattainment, consistently taking into account cost *and* state-by-state impacts, testing its models against reality, and setting reasonable compliance deadlines. But Congress did not authorize EPA to proceed in the unconstrained and heavy-handed manner at issue here. Because it is unlawful and arbitrary, this Court should vacate CSAPR.

STATEMENT OF THE CASE

A. Statutory Framework

The CAA requires EPA to issue NAAQS for each air pollutant that "cause[s] or contribute[s] to air pollution which may reasonably be anticipated to endanger public health or welfare." 42 U.S.C. §7408(a)(1)(A).[1] It also requires EPA to divide the country into areas designated as "nonattainment," "attainment," or "unclassifiable" for each air pollutant, depending on whether the area meets the NAAQS. *Id.* §7407(c), (d). Although EPA is responsible for setting NAAQS, each State has "the primary responsibility for assuring air quality" within its borders, *id.* §7407(a), and must create a state implementation plan (SIP) to meet the relevant NAAQS, which it submits to EPA for approval. *Id.* §7410. This cooperative-federalism structure—and allocation of responsibility—is a central feature of the statutory scheme. *See* State and Local Petitioners' Opening Brief.

B. Interstate Transport Provision

The provision at issue in this case—known as the "interstate transport" provision—requires that SIPs "contain adequate provisions—(i) prohibiting … any source … within the State from emitting any air pollutant in amounts which will—(I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any [NAAQS]." 42 U.S.C. §7410(a)(2)(D)(i)(I). As pertinent here, various sources, including power plants, emit sulfur dioxide (SO_2) and

1 NAAQS are statistical measures of air quality for particular pollutants.

nitrogen oxides (NO_X), which can contribute to a "downwind" State's "nonattainment" of the NAAQS for fine particulate matter ($PM_{2.5}$) and ozone. 76 FR at 48209-10. EPA's efforts to regulate cross-border SO_2 and NO_X emissions pursuant to the interstate transport provision have been the subject of two prior challenges before this Court.

NO_X SIP Call. In 1998, relying on §110(a)(2)(D)(i)(I), EPA issued the "NO_X SIP Call," which instructed more than 20 States to revise their SIPs to mitigate interstate transport of ozone through a regional allowance trading program. 63 FR 57356 (Oct. 27, 1998). This Court addressed challenges to the NO_X SIP Call in *Michigan v. U.S. EPA*, 213 F.3d 663 (D.C. Cir. 2000). The principal dispute was whether EPA could consider costs in determining each State's emissions budget. *Id.* at 676. This Court concluded that the language of §110(a)(2)(D)(i)(I) does not preclude EPA from considering costs and held that the agency could do so to justify "termination … of only a subset of each state's contribution." *Id.* at 675.

CAIR. In 2005, EPA promulgated a second regional allowance trading rule addressing interstate transport—CAIR—again invoking §110(a)(2)(D)(i)(I). 70 FR 25162 (May 12, 2005). EPA determined that upwind SO_2 and NO_X emissions from more than 25 States "contribute significantly to nonattainment" for 1997 $PM_{2.5}$ and/or ozone NAAQS in downwind States. *Id.* EPA required upwind States to revise their SIPs to achieve EPA-specified emission reductions. EPA also permitted power plants to trade emission allowances in order to satisfy CAIR's requirements. *Id.* at 25273-91.

This Court invalidated CAIR as beyond EPA's authority, holding EPA had not properly tailored its budgets to individual upwind States' emissions that actually "contribute significantly" to nonattainment in downwind States. *North Carolina*, 531 F.3d at 907-08. "Because EPA evaluated whether its proposed emission reductions were 'highly cost effective,' at the regionwide level assuming a trading program, it never measured the 'significant contribution' from sources within an individual State to downwind nonattainment areas." *Id.* at 907. As this Court explained, "EPA can't just pick a cost for a region, and deem 'significant' any emissions that sources can eliminate more cheaply"; such an approach failed to give effect to the statutory directive "of prohibiting sources 'within the State' from contributing significantly to downwind nonattainment." *Id.* at 918.

Similarly, this Court rejected EPA's effort to re-allocate the burdens among the States in a way it considered "fair[ ]." *Id.* at 918-19. Rather, under §110(a)(2)(D)(i)(I), "[e]ach state must eliminate its own significant contribution to downwind pollution," and "[w]hile CAIR should achieve something measurable towards that goal, *it may not require some states to exceed the mark*." *Id.* at 921 (emphasis added).

C. CSAPR

The rule under review here—CSAPR—represents EPA's efforts to cure "CAIR's fundamental flaws," *North Carolina v. EPA*, 550 F.3d 1176, 1178 (D.C. Cir.

2008), and EPA again invokes §110(a)(2)(D)(i)(I) as its source of authority. CSAPR applies to 27 States and purports to address emissions that affect downwind States' ability to meet NAAQS for annual $PM_{2.5}$, 24-hour $PM_{2.5}$, and ozone. 76 FR at 48208-09. It caps both annual and ozone-season NO_X and establishes two groups of States for SO_2 reductions with varying levels of reduction required based on cost. *Id.* at 48210-11. CSAPR permits allowance trading, but in a much more limited fashion than was allowed under CAIR. *Id.* at 48212.

"Significant Contribution." In CSAPR, EPA used a two-step process to determine "significant contribution" and "interfere[nce] with maintenance." First, EPA used the Comprehensive Air Quality Model with Extensions (CAMx) along with 2005 emissions and 2005 "base year" air quality data[2] to project downwind "receptors"[3] that would have problems attaining or maintaining the NAAQS in 2012, absent the emission controls mandated by CAIR. *Id.* at 48211. In so doing, EPA departed sharply from its prior approach in the NO_X SIP Call and CAIR, where it used a "monitored-plus-modeled" approach that confirms modeling data with real-world air quality data. 62 FR 60318, 60324-25 (Nov. 7, 1997) (proposed NO_X SIP Call); 63 FR at 57374-75 (NO_X SIP Call); 69 FR 4566, 4581 (Jan. 30, 2004) (proposed

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[2] For air quality projections, EPA used three data sets from the 2003 to 2007 period centered around 2005—*i.e.*, 2003-2005, 2004-2006, 2005-2007. 76 FR at 48228-30. Thus, 2005 air quality data (the "base year") was given the most weight.

[3] Metropolitan areas typically have multiple "receptor" locations and EPA measures and projects air quality at these individual receptor locations.

CAIR); 70 FR at 25174 (CAIR). EPA decided that it did not need to "verif[y] the nonattainment and maintenance receptors [EPA was projecting] against the most recent ambient data." 76 FR at 48230. EPA concluded that such data were irrelevant because they reflected the reductions imposed by CAIR, while EPA was projecting emissions that would result if CAIR were not in place. *Id.*

After identifying projected downwind "nonattainment" and "maintenance" receptors, EPA then used its air quality models to measure "contribution" by upwind States to these receptors. *Id.* at 48233-36. EPA set air quality thresholds at 1% of each NAAQS.[4] *Id.* at 48236. States whose "contributions" to a nonattainment or maintenance receptor met or exceeded this threshold were deemed "linked" to that receptor and subjected to emissions budgets. *Id.* at 48236. EPA concluded that "states whose contributions are below these thresholds do *not* significantly contribute to nonattainment," *id.* (emphasis added), and thus are not subject to any emissions budgets.

For those States with contributions at or above these thresholds, EPA's second step was to determine each State's specific "emissions budget" by analyzing the costs of emission reductions. In this step, EPA did not consider the amount of $PM_{2.5}$ and/or ozone that the upwind State was "contributing" to a downwind State. *Id.* at 48255. EPA instead identified the emission reductions available (for 2012 and 2014)

4 The 1% thresholds for the NAAQS at issue are 0.15 $\mu g/m^3$ for annual $PM_{2.5}$, 0.35 $\mu g/m^3$ for 24-hour $PM_{2.5}$, and 0.8 ppb for ozone. *Id.* at 48236.

at various cost thresholds and then purportedly set the budgets based on the total emissions that would occur at those cost thresholds. *Id.* at 48248–52, 48258. "In other words, EPA determined for specific cost per ton thresholds, the emission reductions that would be achieved in a state if all [covered units] … in that state used all emission controls and emission reduction measures available at that cost threshold." *Id.* at 48248; *see also id.* at 48258. EPA thus estimated the maximum achievable emissions reductions in a State at the relevant cost threshold and set the State's budget based on that cost-derived figure. *Id.*[5]

For the 2012 budgets, EPA used a $500/ton cost threshold for both SO_2 and NO_X and assumed that no major new controls could be installed (since it would not be possible to design, obtain permits for, and install such controls in five months). *Id.* at 48252, 48257–59. For the 2014 budgets, EPA split the States into two groups for SO_2, using $2,300/ton for Group 1 States and $500/ton for Group 2 States. *Id.* at 48252. The 2014 NO_X budgets were purportedly based on the $500/ton threshold. *Id.* at 48257.

[5] Under EPA's approach, a State that was "linked" to a projected downwind nonattainment or maintenance receptor but that could not make any "cost-effective" reductions at EPA's chosen cost thresholds would not be considered to be "significantly contributing." 76 FR at 48263. This was the case with regard to five States for NO_X. EPA, however, subjected these five States to emissions budgets on the basis of a "leakage" theory—*i.e.*, that these States' emissions would increase if emissions budgets were imposed on other States but not these five States. *Id.*

According to EPA, these cost thresholds would produce "cost-effective" and "reasonable" emission reductions that would eliminate nonattainment and maintenance issues at nearly all downwind locations of concern. *Id.* at 48259; *see also id.* at 48248. EPA's data showed that the reductions associated with its cost thresholds were generally greater than what would be required to achieve or maintain the relevant NAAQS. Air Quality TSD, App. B (JA2546-699). EPA did not examine whether controls costing less than $500/ton would also produce downwind air quality that eliminated the "linkage" or attained the relevant NAAQS. 76 FR at 48256-58.

EPA set the State emissions budgets using a computer model (IPM), projecting future utilization and emissions by generating units in each State subject to CSAPR. *Id.* at 48225. The predicted emissions for 2012 and 2014 without CSAPR or CAIR are referred to as a State's "base case" emissions. *Id.* at 48214. EPA used IPM to predict the emission reductions available from the base case at either $500/ton or $2300/ton. As a general matter, EPA set a State's emissions budget by taking its base case and subtracting the "cost-effective" emission reductions. *Id.* at 48248. For those States projected to have lower base case emissions in 2014 than 2012 (typically because of reductions mandated by State law), EPA mandated that further reduced level as the States' 2014 budget, even if those reductions were modeled to cost more than EPA's chosen thresholds. *Id.* at 48261.

Federal Implementation Plans. Unlike the NO_X SIP Call and CAIR, CSAPR does not allow for SIPs at the outset of the program. Instead, CSAPR dictates through federal implementation plans (FIPs) how States must achieve the mandated emission reductions. The FIPs establish the state budgets and allocate emissions allowances to each power plant source within a State based on the State's budget. *Id.* at 48210, 48212, 48284.

Changes from Proposed to Final Rule. Between the proposed and final rules, EPA made "significant updates to the IPM model for projecting EGU emissions." *Id.* at 48260. Additionally, EPA admits that it made "numerous" changes to its significant contribution analysis, and that it "modified the methods used to determine state emissions budgets." *See* Primary Response to Comments at 470 (JA1779). EPA also modified the air quality "modeling used to identify nonattainment and maintenance receptors, [its] source apportionment modeling, and [its] development and use of CAMx and [Air Quality Assessment Tool models] for identifying significant contribution to non-attainment and interference with maintenance." *Id.*

The final rule included new States not included in the proposed rule and radically different state budgets. For example, Texas was not included in the proposed rule for annual SO_2 and annual NO_X, but was added in the final rule. 76 FR at 48213-14. By contrast, Connecticut, Delaware, the District of Columbia, and Massachusetts were included in the proposed rule, but are not covered by the final rule. *Id.* at 48214. These changes, including the "sheer magnitude of change to the budgets of all the states[,] result[ed] in a significantly different rule than originally proposed." OMB, Summary of Interagency Working Comments, EPA-HQ-OAR-2009-0491-4133, at 11 (JA3493) ("OMB Comment"). And such changes were made without providing notice and an opportunity to comment.

D. CSAPR's Compliance Deadlines

EPA imposed an initial compliance deadline of January 1, 2012—less than five months after the rule was issued—and a second compliance phase beginning January 1, 2014, after the program has been in effect for only two years. *See* 76 FR at 48211. Such truncated deadlines are unprecedented for a rule of this magnitude. By contrast, CAIR provided almost four years between the final rule and the first NO_X compliance deadline and almost five years between the final rule and the first SO_2 compliance deadline. 70 FR at 25216. Similarly, the NO_X SIP Call provided more than four years between the final rule and the compliance deadline. 63 FR at 57366.

E. Procedural History

EPA published CSAPR on August 8, 2011. *See* 76 FR 48208. States, local governments, power plants, industrial interests, labor unions, coal mining companies, and trade associations challenged the rule in 45 consolidated petitions for review. On December 30, 2011, this Court stayed the rule and directed EPA to "continue administering [CAIR]" pending review of CSAPR. Dkt. 1350421 at 2 (Dec. 30, 2011).

Numerous related petitions for review are pending or expected because of further EPA action related to CSAPR. *First*, EPA issued a final rule on December 27, 2011, adding six new States to CSAPR's ozone season NO_X program. 76 FR 80760

(Dec. 27, 2011). Two petitions for review have already been filed in this Court. *See* Case Nos. 12-1023, 12-1026. *Second*, EPA proposed corrections to CSAPR on October 14, 2011, recognizing numerous "errors" in its modeling and proposing substantial increases in some emissions budgets. *See generally* 76 FR 63860, 63862 (Oct. 14, 2011) ("Error Corrections Notice"). EPA finalized that proposal on February 7, 2012—just two days before this brief was due—but it has not yet been published in the Federal Register. *Third*, and relatedly, EPA on February 7, 2012 also released a "direct final rule" and notice of proposed rulemaking addressing additional changes in emission budgets based on yet additional errors in its modeling. *Finally*, numerous parties filed administrative petitions for reconsideration regarding CSAPR.

SUMMARY OF ARGUMENT

Three years ago, in *North Carolina*, this Court remanded EPA's prior interstate transport rule—CAIR—after identifying numerous "fatal flaws" in the rule and holding that EPA had exceeded its statutory authority under CAA §110(a)(2)(D)(i)(I). 531 F.3d at 901-02. CSAPR suffers from many of the same errors that doomed CAIR, as well as other fatal defects that independently require vacatur.

First, EPA's methodology for setting CSAPR's state budgets repeats the central error this Court identified in *North Carolina*: EPA made no attempt to tie its State emissions budgets to the amount of each State's "significant contribution" to nonattainment in downwind States. CAA §110(a)(2)(D)(i)(I) requires State plans to "prohibit[] ... emissions activity within the State" in "amounts which will ... contribute significantly" to attainment problems in other States. 42 U.S.C. §7410(a)(2)(D)(i)(I). In *North Carolina,* this Court held that this provision authorizes EPA only to address "each State's significant contribution to specific downwind nonattainment areas," and is not a blank check to address interstate pollution on a regional basis as EPA sees fit without regard to an individual upwind State's actual contribution to downwind air quality. 531 F.3d at 907. Despite the statute's clear and limited mandate and this Court's holding in *North Carolina*, CSAPR sets emissions budgets based solely on uniform cost thresholds that EPA deems "reasonable." Like CAIR, therefore, CSAPR "is not effectuating the statutory mandate [under §110(a)(2)(D)(i)(I)], leaving EPA with no statutory authority for its actions." *Id.* at 908.

Second, CSAPR's requirements are *by definition* stricter than the CAA authorizes because—as EPA concedes—they exceed the reductions necessary for downwind States to achieve and maintain attainment. Under §110(a)(2)(D)(i)(I), however, a SIP may "prohibit" only those "amounts" of emissions that "contribute significantly to nonattainment in" a downwind State. To the extent that the NAAQS can be achieved and maintained by a downwind State, EPA has no authority under §110(a)(2)(D)(i)(I) to impose *further* upwind emission reductions. In this respect, too, CSAPR contravenes a plain limitation on EPA's statutory authority.

Third, EPA's "significant contribution" methodology is arbitrary. EPA failed to consider whether less costly emissions controls would achieve the same downwind air quality results as the more expensive controls it imposed. EPA then amplified this error by making results-oriented *ad hoc* adjustments to its methodology to achieve tighter budgets.

Fourth, even if EPA's interpretation of "significant contribution" were consistent with the CAA, the air quality modeling relied on by EPA to implement its "significant contribution" methodology was flawed. Rather than following its own sensible historical practice of consulting current air quality data, EPA arbitrarily dismissed contrary "recent 'real world' data" as "simply [ ] irrelevant," Dkt. 1333987 at 15 (Oct. 6, 2011), and relied solely on computer modeling (based primarily on 2005 data) to project air quality for 2012-14, *see also* 76 FR at 48231-32. That modeling was flawed because, among other things, EPA failed fully to account for emission reductions that the agency itself had mandated. And EPA's modeled predictions are implausible in light of the real-world data it arbitrarily chose to ignore. Moreover, to the extent EPA's air quality projections should be given weight, they show downwind attainment being achieved in many instances even absent CSAPR's unlawful emissions budgets.

Fifth, EPA's methodology was also arbitrary because it relied on flawed IPM projections to set emissions budgets. Indeed, EPA has *conceded* that IPM does not accurately predict emissions at the source level, and for good reason. IPM is based on a number of erroneous premises, such as the agency's assumption that electricity generated within a region can travel anywhere in that region unimpeded by transmission constraints and that many "cogeneration" units will not run even when needed to meet consumer demand. Yet EPA simply aggregated its concededly unreliable source-level predictions to set the state budgets—again, without testing those predictions against available real-world data.

Sixth, EPA's compliance deadlines are arbitrary. The deadlines are unprecedentedly short for a rule of CSAPR's magnitude, infeasible, and not compelled by the attainment deadlines for the applicable NAAQS. EPA sought to justify those deadlines on the theory that sources should have anticipated CSAPR and begun installing enormously expensive controls even *before* EPA promulgated the rule. But EPA cannot justify unrealistic compliance demands based on supposed industry clairvoyance, especially given the significant changes between the proposed and final rule.

For these reasons and as discussed below, CSAPR is unlawful and should be vacated.[6]

STANDING

The Industry and Labor Petitioners include companies directly regulated by CSAPR, associations representing members regulated by CSAPR, and other entities that will—or whose members will—suffer concrete, particularized injury as a direct result of CSAPR. Because the relief requested will redress those harms, the Industry and Labor Petitioners have Article III standing. *See, e.g.*, *Lujan v. Defenders of Wildlife*,

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[6] The Industry and Labor Petitioners join and adopt the arguments in the State Petitioners' brief, which provides independent grounds for vacating CSAPR.

504 U.S. 555, 561-63 (1992), *Center for Energy & Econ. Dev. v. EPA*, 398 F.3d 653, 656-58 (D.C. Cir. 2005). Industry and Labor Petitioners' standing is clear on the record, *see*, *e.g.*, JA936-58, 997-1046, 1340-93, as well as on the many declarations submitted in the stay proceedings, *see, e.g.,* Addendum attached hereto (A-1 to A-62). *See Sierra Club v. EPA*, 292 F.3d 895, 898 (D.C. Cir. 2002). When standing is beyond dispute for at least some petitioners, as it is here, the Court need not address each petitioner's standing individually. *Military Toxics Project v. EPA*, 146 F.3d 948, 954 (D.C. Cir. 1998).

STANDARD OF REVIEW

The CAA authorizes this Court to set aside EPA action that is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law; … [or] in excess of statutory jurisdiction, authority, or limitations, or short of statutory right." 42 U.S.C. §7607(d)(9). An agency action is "arbitrary and capricious" if the agency "relied on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise." *North Carolina*, 531 F.3d at 906 (citation and quotation marks omitted).

ARGUMENT

I. EPA EXCEEDED ITS STATUTORY AUTHORITY UNDER §110(a)(2)(D)(i)(I) BY SETTING EMISSIONS BUDGETS WITHOUT REGARD TO EACH STATE'S "SIGNIFICANT CONTRIBUTION."

EPA's emissions budgets violate CAA §110(a)(2)(D)(i)(I). That provision requires State plans to "prohibit[] ... emissions activity within the State" in "amounts which will ... contribute significantly" to attainment problems in other States. EPA disregarded that mandate and, instead, determined each State's emission reductions on the basis of uniform cost thresholds—with no consideration of each State's relative "contribution" to the air quality in downwind states. By ignoring each State's "contribut[ion]" in setting the specific "amounts" of "emissions activity" to "prohibit[]," EPA not only violated the plain language of §110(a)(2)(D)(i)(I) but also committed the same error that this Court identified in *North Carolina*.

A. EPA Has Authority Only To Require Reductions Of "Significant Contributions."

CSAPR employed a two-step approach to emission reductions requirements. First, EPA determined whether an "upwind" State should even be included in CSAPR. If a State was projected to contribute less than 1% of the relevant NAAQS to receptors projected to be in nonattainment or have maintenance problems, EPA determined that it "d[id] not significantly contribute to nonattainment or interfere with maintenance of the relevant NAAQS." 76 FR at 48236; *see also id.* at 48237 ("EPA believes that for both $PM_{2.5}$ and for ozone, it is appropriate to use a threshold of 1 percent of the NAAQS for identifying states whose contributions do not significantly contribute to nonattainment or interfere with maintenance of the relevant NAAQS ….”). Conversely, States that were projected to contribute above these thresholds to a projected nonattainment or maintenance downwind receptor were subject to CSAPR, with their specific obligations determined under step two. Thus, the 1% threshold serves as the "floor" below which any contribution is, by definition, viewed as insignificant.[7]

Second, for States not excluded in step one, EPA determined specific emissions budgets based on the costs of emission reductions from power plants in the State. *Id.* at 48248-49, 48257-59. This second step transgresses §110(a)(2)(D)(i)(I) and contravenes *North Carolina* because EPA established those budgets without considering the degree to which each State's air quality "contribution" is eliminated.

EPA is "a creature of statute," without "constitutional or common law existence or authority," and has "only those authorities conferred upon it by Congress." *Michigan v. EPA*, 268 F.3d 1075, 1081 (D.C. Cir. 2001). Under §110(a)(2)(D)(i)(I), EPA has authority only to require that State plans "prohibit[] ... emissions activity within the State from emitting any air pollutant in *amounts which will*

[7] Commenters showed that EPA's choice of a 1% threshold of NAAQS as the "insignificance" floor was arbitrary because EPA's modeling is not precise enough to make accurate projections at such extremely low levels. Southern Company Comments, EPA-HQ-OAR-2009-0491-2864, at 33-34 (JA1374-75) ("Southern Comments").

... *contribute significantly*" to attainment problems in other States. (Emphasis added.) EPA is not authorized to set a state budget, however "reasonable" EPA may deem it to be, that simply ignores the threshold at which it has determined that States "do *not* significantly contribute." 76 FR at 48236 (emphasis added). Nor may EPA make a generalized assessment that a State has "significantly contributed" to downwind nonattainment and then set emissions budgets without regard to the specific "amounts" of a State's significant contribution.

This Court underscored the point in *North Carolina*, when it invalidated CAIR on the ground that EPA had ignored the statutory focus on each State's "significant contribution." CSAPR suffers from the same fatal flaw. As in CAIR, "EPA's apportionment decisions have nothing to do with each state's 'significant contribution ….'" 531 F.3d at 907. "But according to Congress, individual state contributions to downwind nonattainment areas *do* matter." *Id.* (emphasis added).

In setting emissions budgets here, EPA selected its cost levels[8] based on region-wide air quality modeling projections. Those projections indicate that controls at those price points—if applied simultaneously to *all* contributing States—would reduce *aggregate* emissions by 2014 from those States sufficiently to eliminate virtually all of the attainment problems at the downwind locations collectively linked to those States. *See* 76 FR at 48252 ("With these final cost curves in hand, EPA was able to

[8] The cost levels are: \$2,300/ton of SO_2 for Group 1 States; \$500/ton of SO_2 for Group 2 States; and \$500/ton of NO_X for all States.

identify the *combined reductions* available from upwind contributing states and the downwind state …." (emphasis added)); *see also id.* at 48248, 48255, 48259.

EPA did not consider each State's "contribution," let alone measure or determine whether the emissions budgets it was adopting would drive a State's contribution below the threshold level it had already determined in step one "did not significantly contribute to nonattainment or interfere with maintenance." *Id.* at 48236. Instead, EPA concluded that emissions budgets should be determined purely on the basis of how much a State could reduce emissions at specified cost thresholds. *Id.* at 48259-60.

This Court recognized in *North Carolina* that §110(a)(2)(D)(i)(I) "gives EPA no authority to force an upwind state to share the burden of reducing other upwind states' emissions." 531 F.3d at 921. Instead, "[e]ach state must eliminate its own significant contribution to downwind pollution" and EPA "may not require some states to exceed the mark." *Id.* But in CSAPR, EPA has adopted a methodology under which an upwind State may be compelled to reduce emissions that, by EPA's own definition, are not significant.

By way of illustration, consider two States—one whose emissions are projected to make a contribution of 0.14 $\mu g/m^3$ of annual $PM_{2.5}$ to a downwind nonattainment area and one whose emissions are projected to make a contribution of 0.16 $\mu g/m^3$ to that same area. Under EPA's first step, the first State would not be subject to any mandated reductions under §110(a)(2)(D)(i)(I) because it does not contribute at or above the threshold of 0.15 $\mu g/m^3$ (1% of the NAAQS) and thus is not "significantly contributing." By contrast, the second State is not only subject to the mandated reductions but, depending on costs, may be forced to reduce emissions to the point that it contributes far below 0.14 $\mu g/m^3$. EPA cannot claim to be reducing the emissions of the second State by the "amount" of that State's "significant contribution" while simultaneously finding that the first State, which is contributing higher levels, is not "significantly contributing" at all.

Contrary to EPA's contention, 76 FR at 48270-71, this Court's prior decisions in *Michigan* and *North Carolina* only underscore that EPA's CSAPR methodology is not consistent with §110(a)(2)(D)(i)(I). In *Michigan*, this Court rejected the argument that the CAA prohibits EPA from considering costs altogether and held that EPA may take costs into account so as to *lessen* a State's burden when the costs of reducing emissions would otherwise be too high. The Court reasoned that Congress should not be presumed to authorize an agency to impose regulations so stringent that the benefits are no longer "'roughly commensurate with their costs.'" *See* 213 F.3d at 679.[9] While cost is an appropriate ceiling on reductions that may be required of

[9] The risk of imposing costs that far exceed the benefits of the regulation are particularly present where, as here, EPA has set "a very low threshold of contribution" for deciding which States will be subject to the rule. *Michigan*, 213 F.3d at 675. In such circumstances, it is especially important for the agency to be able to relieve the State from having to achieve that low level when little benefit would result. By contrast, a low threshold makes it especially implausible to suggest that Congress meant the agency to be able to require reductions that go even *deeper*.

contributing States, nothing in *Michigan* authorizes EPA to use cost as a sword to force a State to reduce emissions to levels that EPA has concluded are insignificant.

And *North Carolina* in any event forecloses EPA's approach. This Court invalidated CAIR on the ground that EPA failed to set budgets based on "each state's significant contribution to specific downwind nonattainment areas." 531 F.3d at 907; *see also id.* at 918. As the Court explained:

> While EPA may require "termination of only a *subset of each state's contribution,*" by having states "cut[ ] back the amount that could be eliminated with 'highly cost-effective controls,'" *Michigan,* 213 F.3d at 675 (emphasis added), EPA can't just pick a cost for a region, and deem "significant" any emissions that sources can eliminate more cheaply.

Id. at 918. That is precisely what EPA has attempted to do in CSAPR.

B. EPA Cannot Use §110(a)(2)(D)(i)(I) To Shift Downwind States' Statutory Obligations To Upwind States.

EPA's methodology also contravenes the structure of the CAA. EPA acknowledges that CSAPR effectively compels upwind States to ensure that downwind States can achieve attainment regardless of the upwind States' level of contribution and regardless of whether the downwind States have established appropriate local control programs. *See* 75 FR 45210, 45226 (Aug. 2, 2010) ("EPA continues to believe that a strategy based on cost effective controls on sources transported pollutants as a first step will produce a more *reasonable, equitable and optimal strategy than one beginning with local controls.*") (emphasis added); *id.* at 45241 ("[A]ny local control programs that may be necessary for areas to attain … NAAQS are *not* included in the future base case projections.") (emphasis added). Thus, EPA unlawfully premised its methodology on the assumption that it may impose emission reductions on upwind States to the extent necessary to ensure that any attainment problems are eliminated in the downwind location. 76 FR at 48248 (EPA's "methodology" is intended to impose "emission reductions … in a specific upwind state *which effectively address nonattainment and maintenance of the relevant NAAQS* …." (emphasis added)); *see also id.* at 48259 (justifying reductions on basis that they eliminate virtually all projected downwind attainment and maintenance problems). Indeed, EPA has imposed strict upwind emissions budgets designed to achieve downwind attainment even where it has explicitly recognized "local sources are at the heart of the $PM_{2.5}$ problem." 76 FR 68699, 68703 (Nov. 7, 2011) (discussing Allegheny, Pennsylvania).

But Congress did not give the agency *carte blanche* to shift the burden to upwind States to improve air quality at downwind sites to the extent EPA deems it "reasonable, equitable, and optimal." Although the absence of downwind air quality problems eliminates EPA's authority under §110(a)(2)(D)(i)(I), the mere presence of downwind problems is not sufficient to trigger EPA's limited authority under that provision. Rather, §110(a)(2)(D)(i)(I) directs upwind States only to eliminate their own "significant contribution" to downwind air quality problems.

Under CAA §107(a), "[e]ach State shall have the primary responsibility for assuring air quality within the entire geographic area comprising such State." 42

U.S.C. §7407(a). Where an area of a State is in nonattainment, *that State*—not its upwind neighbors—has the primary responsibility for bringing the area into attainment. *Id.* §7502. Thus, as EPA itself has recognized, "[s]ection 110(a)(2)(D)(i)(I) only requires the elimination of emissions that *significantly contribute* to nonattainment or interfere with maintenance of the NAAQS in other states; it does not shift to upwind states the responsibility for ensuring that all areas in other states attain the NAAQS." 76 FR at 48210; *see also id.* at 48256.

In short, by requiring an upwind State to eliminate only its "significant contribution," §110(a)(2)(D)(i)(I) reinforces §107(a)'s mandate that downwind States retain the primary responsibility for ensuring that they meet NAAQS. By redefining the goal of §110(a)(2)(D)(i)(I) as ensuring downwind attainment, CSAPR turns the CAA's statutory structure on its head.

II. EPA EXCEEDED ITS STATUTORY AUTHORITY UNDER §110(a)(2)(D)(i)(I) BY IMPOSING EMISSION REDUCTIONS ON UPWIND SOURCES MORE STRINGENT THAN NECESSARY FOR DOWNWIND STATES TO ATTAIN OR MAINTAIN NAAQS.

As explained above, §110(a)(2)(D)(i)(I) establishes a limited obligation on the part of upwind States to eliminate their "significant contribution" to downwind nonattainment; it does not shift to upwind States the responsibility to make whatever emission reductions are necessary for downwind States to achieve "attainment." "Attainment" *is* relevant in an important respect that EPA neglected here, however:

EPA's authority to impose upwind emissions reductions under §110(a)(2)(D)(i)(I) ends at the point that a downwind State can attain and maintain the NAAQS.

Under the plain language of §110(a)(2)(D)(i)(I), EPA may require only that a SIP "prohibit" "amounts" of emissions that "contribute significantly to *nonattainment in, or interfere with maintenance by*" a downwind State "with respect" to a NAAQS. EPA made no effort to comply with that limitation here and instead simply set budgets based on its view of what constitutes "reasonable" and "cost-effective" emission controls irrespective of downwind attainment status. *See, e.g.*, 76 FR at 48249 (setting cost controls at the "point where large upwind emission reductions become available because a certain type of emissions control strategy becomes cost-effective"); *id.* at 48248 ("EPA's methodology is intended to 'assign a substantial but reasonable amount of responsibility to upwind states ….'"); *id.* at 48257 (EPA's cost controls achieved "significant air quality improvements" with "cost impacts [that] remained reasonable"). EPA thus imposed emission reductions beyond those necessary for the downwind States to achieve and maintain "attainment," in direct violation of §110(a)(2)(D)(i)(I).

For example, EPA projected "design values"—*i.e.*, EPA's statistic for measuring air quality relative to the NAAQS[10]—for receptor locations on the

[10] A higher design value denotes worse air quality relative to the NAAQS. Here, the relevant NAAQS attainment thresholds are 15 $\mu g/m^3$ for annual $PM_{2.5}$, 35 $\mu g/m^3$ for 24-hour $PM_{2.5}$ and 85 ppb for 8-hour ozone. 76 FR at 48233-36.

assumption that CAIR and CSAPR requirements were not in place in 2012. This "base case" projection estimated that 16 downwind receptors would not be able to achieve attainment with the annual $PM_{2.5}$ NAAQS. *See* 76 FR at 48233-34; Significant Contribution TSD at 35 (JA2964). EPA also made "remedy case" projections—*i.e.*, the projected air quality in 2014 for those problem receptors after CSAPR's budgets were imposed. EPA projected that for 2014, each one of these receptor locations would achieve a design value *superior to* the relevant annual NAAQS, many by a substantial margin. *See* Air Quality TSD at B35-63 (JA2580-608) (listing 2014 remedy case design values for annual $PM_{2.5}$ for all downwind locations modeled by EPA); Significant Contribution TSD at 35 (JA2964) (listing 2014 remedy case design values for projected annual $PM_{2.5}$ "nonattainment" receptors). In fact, EPA estimated that CSAPR's emission budgets on average would push annual $PM_{2.5}$ levels down to 12.74 $\mu g/m^3$ in 2014 for these 16 locations—well below the 15 $\mu g/m^3$ NAAQS attainment threshold.[11] Significant Contribution TSD at 35 (JA2964); Air Quality TSD at B35-63 (JA2580-608).

EPA's budgets likewise are admittedly intended to impose reductions far beyond what are necessary for the downwind States to achieve NAAQS for 24-hour

[11] The difference between the annual $PM_{2.5}$ NAAQS and the average air quality levels that EPA sought to impose in CSAPR is 2.26 $\mu g/m^3$—more than 15 times the level of "significant contribution" that triggered imposition of emission controls.

$PM_{2.5}$[12] and ozone[13] for the substantial majority of the relevant locations. *See also* 76 FR 70091, 70099 (Nov. 10, 2011) (CSAPR "mandates … more reductions than are needed to maintain the [24-hour $PM_{2.5}$ standard in [Birmingham]").

EPA defended its approach as improving "average" downwind air quality, 76 FR at 48255, and on the theory that its emissions budgets reflected the "'knee-in-the-curve' area of cost-effectiveness," *id.* at 48258. Taken to its (illogical) extreme, EPA's reading of §110(a)(2)(D)(i)(I) would allow the agency to virtually eliminate emissions by an upwind State simply because doing so might produce better downwind air quality or because EPA believed the mandated emission reductions were "cost-effective." *See id.* at 48257-59. This position contravenes §110(a)(2)(D)(i)(I), which neither authorizes EPA to require emission reductions beyond those that "significantly contribute" or "interfere," nor permits EPA to impose any upwind reductions once downwind areas achieve and maintain the NAAQS. *See, e.g., AT&T Corp. v. Iowa Utils. Bd.*, 525 U.S. 366, 388 (1999) (invalidating rules where agency failed

[12] *See* Air Quality TSD at B64-92 (JA2609-37) (listing 2014 "remedy case" design values for 24-hour $PM_{2.5}$ for all downwind locations modeled by EPA); Significant Contribution TSD at 36 (JA2965) (listing 2014 "remedy case" design values for projected 24-hour $PM_{2.5}$ "nonattainment" and "maintenance" receptors relative to NAAQS attainment threshold of 35 $\mu g/m^3$). EPA projected that after the imposition of emission controls, the 24-hour $PM_{2.5}$ receptors of concern would achieve, on average, a design value of 29.53 $\mu g/m^3$, which is well below the NAAQS of 35 $\mu g/m^3$. Significant Contribution TSD at 36 (JA2965).

[13] *Compare* 76 FR at 48244-46 (listing projected "nonattainment" and "maintenance" receptors for 8-hour ozone), *with* Air Quality TSD at B4-34 (JA2549-79) (listing 2014 "remedy case" design values for 8-hour ozone for all downwind locations modeled by EPA relative to NAAQS attainment threshold of 85 ppb).

to apply "*some* limiting standard, rationally related to the goals of the Act"); *United States Telecom Ass'n v. FCC*, 290 F.3d 415, 428 (D.C. Cir. 2002) (striking down rule that was "so broad and unrooted in any analysis of the competing values at stake in implementation of the Act").

In all events, EPA's action was arbitrary. It not only forced upwind States to reduce emissions more than necessary to achieve attainment, but it imposed especially onerous obligations on some States without any rational basis. For example, with regard to annual $PM_{2.5}$, EPA projects that CSAPR's emission reductions will result in average annual $PM_{2.5}$ design values of 14.62 $\mu g/m^3$ for Allegheny, Pennsylvania, 12.01 $\mu g/m^3$ for Marion, Indiana, and 13.28 $\mu g/m^3$ for Madison, Illinois. Significant Contribution TSD at 35 (JA2964). But EPA provides no explanation as to why—if the level of air quality it projected for Allegheny is acceptable—the States linked to Marion and Madison should nonetheless be forced to reduce emissions to levels that push those downwind areas' $PM_{2.5}$ levels much further below the NAAQS.[14] Subjecting similarly situated parties to dissimilar treatment is the paradigm of arbitrary agency action. *See, e.g.*, *Westar Energy, Inc. v. FERC*, 473 F.3d 1239, 1241 (D.C. Cir. 2007).

[14] The same holds for the 24-hour $PM_{2.5}$ and 8-hour ozone NAAQS. *See* Significant Contribution TSD at 36 (JA2965) (listing 2014 "remedy case" design values for projected 24-hour $PM_{2.5}$ "nonattainment" and "maintenance" receptors); Air Quality TSD at B4-34 (JA2549-79) (listing 2014 "remedy case" design values for 8-hour ozone for all downwind locations analyzed by EPA).

III. EPA'S APPLICATION OF ITS "SIGNIFICANT CONTRIBUTION" METHODOLOGY WAS ARBITRARY AND CAPRICIOUS.

Even assuming *arguendo* EPA had authority to define "significant contribution" based on regional cost thresholds and without regard to the level below which it determined an upwind State "do[es] not significantly contribute," 76 FR at 48236-37, or a downwind state would already achieve "attainment," EPA failed to implement its methodology consistent with the requirements of the CAA. Rather, EPA made multiple *ad hoc* adjustments designed to impose stricter emissions budgets even when its underlying methodology, if consistently applied, would mandate less restrictive budgets.

A. EPA Arbitrarily Selected Cost Thresholds In Setting State Budgets.

EPA's "significant contribution" methodology established emissions budgets based on estimates of emission reductions that could be obtained by upwind States at a specified cost-per-ton level. In selecting these cost thresholds, however, EPA did not analyze whether *lower* cost controls would be sufficient to achieve the NAAQS at downwind nonattainment and maintenance locations, although this was purportedly the touchstone of EPA's "significant contribution" analysis. *See, e.g.*, 76 FR at 48248.

Indeed, EPA conceded that it selected the uniform $500/ton threshold for NO_X without modeling whether its desired goal of downwind attainment could be achieved at lower costs. *Id.* at 48256. EPA's sole explanation was that some power plants might discontinue operation of some existing controls if a cost threshold of less than \$500/ton were employed. *Id.* at 48256-57. But EPA's results-oriented justification contravenes the objective determination required by §110(a)(2)(D)(i)(I). If less costly levels of NO_X controls would still allow downwind States to achieve and maintain attainment—as the evidence here indicates, Utility Air Regulatory Group Comments, EPA-HQ-OAR-2009-0491-2756, at 70-72 (JA1066-68) ("UARG Comments")—then there is no legal basis or technical justification under EPA's own methodology for mandating more controls. *Cf. Public Serv. Comm'n of N.Y. v. FERC*, 813 F.2d 448, 465 (D.C. Cir. 1987) (holding that "result-oriented manipulation of an objective ratemaking calculation is patently arbitrary and capricious decisionmaking").

EPA's approach to SO_2 controls was, if anything, more arbitrary. Foremost, EPA refused to consider the impact of SO_2 controls costing less than \$500/ton—despite having gathered data on such controls. *See* Analysis to Quantify Significant Contribution at 30-31 (JA2192-93). EPA offered *no justification* for its refusal, *see* 76 FR at 48257-58, even though the data demonstrated that "similar air quality benefit[s] could be achieved at between \$200 and \$400 per ton of SO2." Southern Comments at 33 (JA1374).

Also arbitrary were EPA's decision as to which States to include in Group 1, and its application of a uniform \$2300/ton threshold for all States in that group. Once EPA determined which downwind receptors would not be in attainment under the uniform \$500/ton cost threshold for SO_2, it lumped the upwind States that are "linked" to those downwind receptors into a separate category (Group 1) to which it applied a single cost threshold of $2,300/ton. 76 FR at 48255, 48258, Table VI.D-1.[15] Not only did EPA fail to assess whether these upwind Group 1 States were still contributing over the threshold "significant contribution" levels after application of the $500/ton reductions, it did not even consider the *relative* contributions of the various States. That approach resulted in States with relatively minor contributions being included in Group 1, not because of the extent of their own emissions, but because of the severity of downwind air quality. *Compare id.* at 48240, 48248 (projected contribution by State) *with id.* at 48257 (Group 1 States).

Moreover, while EPA did investigate cost thresholds for Group 1 States below the $2,300/ton level for SO_2 control, it did not look at each State individually to determine whether $2,300/ton was appropriate for each State assigned to that group. EPA justified its selection of $2,300/ton for the Group 1 States as the only threshold that resolved the remaining downwind nonattainment/maintenance issues with the annual and 24-hour $PM_{2.5}$ NAAQS, *id.* at 48257, but it never considered whether $2,300/ton was necessary to eliminate the significant contribution of each Group 1 State. In effect, EPA used a "highest common denominator" approach to Group 1, rather than judging what cost threshold would appropriately address significant contribution by each State.

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15 As noted above, the proper statutory inquiry was whether a State had eliminated its "significant contribution," not whether downwind States were projected to attain the NAAQS.

EPA's own data underscore the arbitrary nature of its analysis. Increasing SO_2 control costs above $1,600/ton has no impact on annual $PM_{2.5}$ attainment or maintenance and only limited effects on 24-hour $PM_{2.5}$. *Id.* at 48255, Table VI.C.-2. That suggests that the perceived need for a $2,300/ton threshold was driven by (at most) just a few Group 1 States. EPA's overbroad and unjustified Group 1 determination was not the product of reasoned decision-making, but the "results-oriented manipulation" of its own methodology. *See Public Serv. Comm'n of N.Y.*, 813 F.2d at 465.

B. EPA Arbitrarily Used A One-Way Ratchet To Further Tighten Emissions Budgets.

EPA also arbitrarily departed from its own cost threshold approach in several instances to achieve its policy preference of stricter emissions budgets. Specifically, EPA found that power plant emissions in some States would decrease from 2012 to 2014, independent of CSAPR. Significant Contribution TSD at 7 (JA2936); 76 FR at 48261.[16] At the same time, EPA projected that other States' emissions would increase over this period, which EPA attributed to changes in dispatch and generation-shifting among States. *Id.* But rather than accepting the budgets yielded by its chosen methodology, EPA selectively restricted certain States' emissions budgets, thereby

[16] For example, without CAIR or CSAPR controls, EPA's IPM modeling showed Georgia's SO_2 emissions falling from 405,933 to 169,702 tons and its NO_X emissions falling from 66,384 to 47,808 tons from 2012 to 2014, due at least in part to independently-mandated emission reductions by the State. Significant Contribution TSD at 11, 14 (JA2940, 2943).

effectively increasing costs for those States. As to States with independently-mandated reductions—which by themselves would have ameliorated or eliminated that State's significant contribution by 2014, perhaps rendering transport regulation unnecessary—EPA effectively stacked CSAPR's "$500/ton" emission reductions on top of the State-mandated reductions in 2014, making both federally-enforceable through its CSAPR FIP. 76 FR at 48261. Thus, for example, Georgia's emissions budget for SO_2 drops from 158,527 tons in 2012 to 95,231 tons in 2014, even though EPA purportedly applied the same $500/ton criterion to both years. *Id.* EPA acknowledges in the final rule that this "sharp reduction[]" is driven by state rule requirements "unrelated to [CSAPR]." *Id.*; *see also* Primary Response to Comments at 675, 677 (JA1984, 1986) (conceding that EPA used a downward "ratchet" to "capture" independently-mandated State reductions in its FIP).[17]

Conversely, for States projected to have a rise in their emissions between 2012 and 2014 (*e.g.*, due to increased demand), EPA arbitrarily set those States' 2014 budgets (and beyond) based on the lower 2012 emission projections. Significant Contribution TSD at 7 (JA2936). Doing so, EPA ignored its own projections showing increased emissions in 2014 under CSAPR. EPA thus applied a one-way

[17] EPA says that "other states experience[d] similar reductions" to Georgia, but does not identify them. 76 FR at 48261. Alabama, Indiana, Kansas, Kentucky, North Carolina, Ohio and Tennessee are projected to have lower SO_2 and/or NO_X emissions in the 2014 base case independent of CSAPR and thus appear to have been caught in this downward ratchet for one or both pollutants. *See* Significant Contribution TSD at 11, 14 (JA2940, 2943); 76 FR at 48261-62.

ratchet that adopted the most stringent modeling results, thereby ensuring that several States' budgets reflect more than elimination of "significant contribution," as EPA itself defined it.[18]

In sum, as to States with emissions decreasing from 2012 to 2014 without CSAPR, EPA arbitrarily mandated a second round of emission reductions in 2014 without any determination that such additional reductions were necessary to eliminate the State's significant contribution, and thus this downward ratchet exceeded the agency's statutory authority. 76 FR at 48259. And as to States with emissions modeled to increase from 2012 to 2014, EPA's decision to use the 2012 budget for 2014 arbitrarily violated its own stated methodology by mandating emission reductions in 2014 that exceed the $500/ton cost threshold as calculated by EPA. Significant Contribution TSD at 15 (JA2944). EPA's results-oriented methodology is arbitrary and capricious, and the resulting rule cannot stand. *See Pub. Serv. Comm'n of N.Y.*, 813 F.2d at 465.

[18] For example, EPA's modeling purportedly showed that Kansas EGUs could reduce SO_2 emissions to approximately 55,000 tons in 2014 at the $500/ton threshold. Significant Contribution TSD at 14 (JA2943). But instead of setting Kansas' 2014 SO_2 budget at this level, EPA applied Kansas' 2012 "cost effective" reductions to 2014 (approximately 41,500 tons of SO_2, 76 FR at 48262), effectively mandating reductions that could only be achieved at *greater than* $500/ton in 2014, as shown by EPA's own modeling. Significant Contribution TSD at 15 (JA2944). Many States were caught in this downward ratchet for both NO_X and SO_2. *Compare* 76 FR at 48261-62 (final budgets for 2014 and beyond) *with* Significant Contribution TSD at 10-15 (JA2939-44) (reductions achievable at $500/ton in 2014).

IV. EPA'S RELIANCE ON FLAWED AIR QUALITY MODELING TO DETERMINE UPWIND STATES COVERED BY CSAPR WAS ARBITRARY AND CAPRICIOUS.

Even assuming EPA's "significant contribution" methodology were consistent with the CAA and otherwise sound, EPA arbitrarily relied on flawed air quality projections. In any event, to the extent those air quality projections can be given any weight, those projections fatally undermine, rather than support, EPA's imposition of emissions controls on the 27 States subject to CSAPR.

A. EPA Arbitrarily Ignored Highly-Relevant, Real-World Data.

EPA justified CSAPR's requirements through its base case modeling determinations that various downwind receptor locations would be in nonattainment in 2012 absent emission controls. *E.g.*, 76 FR at 48233-36, 48239, 48244. In making these "linkage" determinations, EPA did not follow its own historical practice of grounding its analysis on current air quality data. *See* UARG Comments at 53-55 (JA1049-51) (discussing EPA's "monitored-plus-modeled" approach used in CAIR and the NO_X SIP Call).

Instead, EPA stated that "relatively recent 'real world' data … simply are irrelevant" to the calculation of projected downwind air quality because recent data reflected CAIR controls that would no longer be required once CSAPR was adopted. Dkt. 1333987 at 15 (Oct. 6, 2011); *see also* 76 FR at 48231-32. But the fact that current air quality data reflects emissions controls adopted to comply with CAIR does not make it irrelevant.

In CSAPR, EPA projected hypothetical future air quality in the absence of CAIR to model future $PM_{2.5}$ and ozone levels at downwind receptors before and after emissions controls were imposed on upwind sources. *See, e.g.*, 76 FR at 48223, 48227-30, 48255; Air Quality TSD, App. B (JA2546-699). These air quality projections can be benchmarked against real-world data. In fact, a comparison of current air quality data and projected air quality after the imposition of CSAPR reveals that in many instances, EPA's projections are facially implausible.

Specifically, the substantial majority of the downwind receptors that EPA projected to be in nonattainment or have maintenance problems in 2012 have air quality that is *currently in attainment*. According to EPA's own measured air quality data, 14 of the 16 (88%) downwind receptors that EPA projects would not attain or maintain annual $PM_{2.5}$ NAAQS have air quality that currently satisfies that standard;[19] 38 of the 41 (93%) downwind receptors that EPA projects would not attain or maintain 24-hour $PM_{2.5}$ NAAQS currently satisfy the standard;[20] and 14 of the 16 (88%) downwind receptors that EPA projects would not attain or maintain ozone

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[19] *Compare* EPA's 2008-2010 Design Value data for PM2.5 ("PM2.5 Design Value Spreadsheet") *available at* http://www.epa.gov/airtrends/pdfs/PM25_DesignValues_20082010_FinalRevised.xlsx (columns J, AC in worksheet "Table6, site DV history"), *with* Air Quality TSD at 28-29 (JA2436-37) (projected 2014 nonattainment sites and maintenance-only sites listed in Tables IV-1 and IV-2, respectively).

[20] *Compare* PM2.5 Design Value Spreadsheet (columns J, AW in worksheet "Table6, site DV history") *with* Air Quality TSD at 30-31 (JA2438-39) (projected 2014 nonattainment sites and maintenance-only sites listed in Tables IV-3 and IV-4, respectively).

NAAQS currently satisfy that standard.[21] *See also* UARG Comments at 53-54 (JA1049-50).[22] But the thrust of EPA's CSAPR rationale is that upwind States need to make substantial aggregate emission reductions *from current levels* for these downwind locations to remain in attainment. *See* 76 FR at 48233-36, 48255; Air Quality TSD, App. B (JA2546-699).[23] This makes little sense.

Perhaps the most vivid illustration of the facially implausible results of EPA's models was EPA's projection that Texas was "significantly contributing" to $PM_{2.5}$ nonattainment at the Granite City receptor in Madison, Illinois. Currently, air quality at that receptor satisfies the annual $PM_{2.5}$ NAAQS, and EPA itself has stated that it "expected" further "significant reductions of $PM_{2.5}$ emissions" from local sources—unrelated to CSAPR. 76 FR 29652, 29654 (May 23, 2011). In addition, EPA's "base case" projects that Texas power plant emissions would decrease from 2010 levels even in the absence of CSAPR's emissions controls. *Compare* Primary Response to

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21 *Compare* EPA's 2008-2010 Design Value data for 8-hour Ozone ("Ozone Design Value Spreadsheet") *available at* http://www.epa.gov/airtrends/pdfs/Ozone_DesignValues_20082010_UPDATE.xlsx (columns G, L in worksheet "Table7"), *with* Air Quality TSD at 33 (JA2441) (projected 2014 nonattainment sites and maintenance-only sites listed in Tables IV-5 and IV-6, respectively).

22 Thus, if EPA had followed its monitored-plus-modeled test, its CSAPR analysis would have identified only seven receptors—2 for annual PM, 3 for daily PM and 2 for ozone.

23 CSAPR "mandates even greater reductions than have already occurred under CAIR." 76 FR at 70099; *see also* 75 FR at 45217 (projecting that proposed controls—which were further tightened in the final CSAPR—would result in substantial emission reductions relative to those that would be permitted under CAIR).

Comments at 564 (JA1873) *with* Emissions Inventory TSD at 104-06 (JA3164-66). Thus, EPA's models predict that Texas "contributes significantly" to "nonattainment" in an area that is in attainment today and where relevant emissions—both in the upwind state and at the receptor—are projected to decrease without any CSAPR (or CAIR) regulation.

There are many other examples. For instance, EPA's current monitoring data (2008-2010) show that a receptor in Wayne, Michigan (receptor 261630033) has a measured design value of 12.3 $\mu g/m^3$ for annual $PM_{2.5}$.[24] EPA's air quality modeling, however, implausibly projects that receptor's design value would increase to 13.59 $\mu g/m^3$ after controls are put in place that *reduce* aggregate contributing upwind emissions. Air Quality TSD at B-48 (JA2593) (projected 2014 annual $PM_{2.5}$ design value for Wayne receptor). Similarly, EPA's models project that after the imposition of CSAPR's emissions budgets (which are stricter than the current CAIR budgets), air quality at the Fulton, Georgia receptor (131210039) would *degrade* (from 11.4 to 12.99

[24] *See* PM2.5 Design Values Spreadsheet (row 731, column AC in worksheet "Table 6, site DV history") (2008-2010 annual $PM_{2.5}$ design value for Wayne receptor).

μg/m^3).[25] Many of EPA's 24-hour $PM_{2.5}$ and ozone projections suffer from the same inconsistency.[26]

These predictions cannot be right—and EPA had an obligation to consider and reconcile the clear inconsistencies between what its models predicted and reality. *Cf. NRDC v. Jackson,* 650 F.3d 662, 666 (7th Cir. 2011) ("The way to test" predictive models is to "compare [the] projection against real outcomes. … An agency that clings to predictions rather than performing readily available tests may run into trouble.") (citing *Bechtel v. FCC*, 10 F.3d 875 (D.C. Cir. 1993)). EPA has recognized this obligation in related proceedings, where it examined its CAMx modeling and real-world monitoring data and concluded that CAMx predicted "anamolous results that do not indicate the true effects" of the emissions scenarios modeled. 76 FR 82219, 82228 (Dec. 30, 2011).

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[25] *Compare* PM2.5 Design Values Spreadsheet (row 338, column AC in worksheet "Table 6, site DV history") (2008-2010 annual $PM_{2.5}$ design value for Fulton receptor), *with* Air Quality TSD at B-39 (JA2584) (projected 2014 annual $PM_{2.5}$ design value for Fulton receptor).

[26] For example, EPA projects that the 24-hour $PM_{2.5}$ design value for Jefferson, Alabama receptor 10730023 will degrade from 29 to 31.1 μg/m^3 after imposition of CSAPR. *Compare* PM2.5 Design Values Spreadsheet (row 15, column AW in worksheet "Table 6, site DV history") (2008-2010 24-hour $PM_{2.5}$ design value for Jefferson receptor) *with* Air Quality TSD at B-64 (JA2609) (projected 2014 24-hour $PM_{2.5}$ design value for Jefferson receptor). EPA similarly projects that 8-hour ozone design value for Allegan, Michigan receptor 260050003 will degrade from .074 to .0804 ppm after imposition of CSAPR. *Compare* Ozone Design Value Spreadsheet (row 629, column L in worksheet "Table 7") (2008-2010 8-hour ozone design value for Allegan receptor) *with* Air Quality TSD at B-16 (JA2561) (projected 2014 24-hour $PM_{2.5}$ design value for Jefferson receptor).

Although EPA may use "predictive models," it may do so only where it "provides a complete analytic defense" including the obligation to "address[] what appear[s] to be stark disparities between its projections and real world observations." *Appalachian Power Co. v. EPA*, 249 F.3d 1032, 1054 (D.C. Cir. 2001) (citation and internal quotation marks omitted). Here, EPA arbitrarily ignored its *own* air quality data and attainment findings when it implausibly projected that further emission reductions than those currently in place would degrade air quality. The unexplained contradictions between what EPA predicted and "real world observations" starkly call into question the accuracy of EPA's air quality projections and render the emissions budgets that are based on those projections arbitrary and unlawful.

B. EPA Arbitrarily Failed To Account For Relevant Rules Affecting Air Quality And Relied On Biased Data.

EPA also failed to account for all relevant "emission reductions that occurred between 2005 and 2012" independent of CAIR or CSAPR and that would impact EPA's attempts to project its 2005 base year data into the future. 76 FR at 48230. Indeed, EPA's modeling ignored rules EPA itself predicted will lead to substantial reductions in NO_X and SO_2. For example, EPA ignored its NSPS for coal preparation and processing plants, 74 FR 51950 (Oct. 8, 2009), even though these standards include emission limits for PM, SO_2 and NO_X for thermal dryers. *Id.* Similarly, EPA did not account for its asphalt processing and asphalt roofing manufacturing rule, 74 FR 63236 (Dec. 2, 2009), which also included PM emissions standards. Furthermore, EPA ignored a number of federally enforceable consent decrees requiring emission reductions. Louisiana Chemical Ass'n Comments, EPA-HQ-OAR-2009-0491-3527, at 24-26 & Exh. 8 (JA1422-24, 1433-38). There are several other examples of EPA rulemakings which the agency concluded will result in reductions of NO_X and SO_2, but which were ignored in its modeling. *Compare* Midwest Ozone Group Comments, EPA-HQ-OAR-2009-0491-2809, at 5-9 (JA1262--66), *with* Emissions Inventory TSD, at 71-74, Table 4-1 (JA3160-63).

EPA's modeling also failed fully to account for State regulation designed to improve air quality independent of CAIR. For example, not only has Michigan undertaken measures that brought Allegan into attainment today, EPA determined that Michigan's maintenance plan was sufficiently robust that Allegan would remain in attainment going forward "*without any additional CAIR requirements.*" 75 FR 42018, 42025-28 (July 20, 2010) (emphasis added). But EPA's model predicts that Allegan will have ozone NAAQS maintenance problems unless nine States—as far away as Oklahoma and Texas—reduce their NO_X emissions. Thus, EPA's models must not have fully accounted for the post-2005 developments that ensure Allegan's air quality will be maintained even absent CAIR (or CSAPR). *See also* Louisiana Chemical Ass'n Comments, EPA-HQ-OAR-2009-0491-3527, at 28 (JA1426) (showing EPA failed to take into account Louisiana SIP rule for NO_X control). Similarly, EPA does not dispute that its models failed to account for the impact of a local steel mill that has a significant impact on air quality at the Madison receptor. *See* 76 FR 29652, 29653

(May 23, 2011); *compare* Dkt. 1329866 at 15-16 & n.10 (Sept. 15, 2011), *with* Dkt. 1333987 at 14-16. Not only has EPA found that air quality has already substantially improved at the receptor location, EPA "expect[s]" a recent agreement between the mill and the Illinois EPA "to provide significant reductions of $PM_{2.5}$" going forward. 76 FR at 29654.

EPA compounded these errors by using biased data. Meteorological conditions for 2005 were "atypical,"[27] including "relatively high ozone during the summer of 2005 and relatively high $PM_{2.5}$ periods during the year," 76 FR at 48230, yet EPA relied on 2005 base year data to project future 2012 base case design values. *Id.* at 48228-30. Although using such data skews EPA's results towards a finding of downwind nonattainment, in its final projections EPA made no attempt to control for this bias or reconcile its predictions with real-world data.

C. CSAPR Is Inconsistent With EPA's Own Air Quality Projections.

Finally, even if EPA's air quality projections were otherwise accurate and lawful, the agency still lacked an adequate basis for adopting CSAPR. EPA "linked" upwind States—*i.e.*, subjected them to CSAPR—where it predicted downwind locations would not satisfy a relevant NAAQS in 2012 if no §110(a)(2)(D)(i)(I) emission controls were in place. *Id.* at 48239, 48244. EPA made no predictions for 2013, so it has no basis for imposing emission reductions in that year.

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[27] *National Air Quality Status and Trends: Particle Pollution* 22, http://www.epa.gov/airtrends/2008/report/ParticlePollution.pdf.

EPA also projected that, in the absence of emission controls under CAIR or CSAPR, many of the locations it had projected would be in nonattainment for the 2012 base case would achieve attainment by 2014 (typically because of independent State regulation and other undertakings by the industry sources to improve air quality).[28] Despite those findings, and despite its claim that it had accounted for "all non-CAIR enforceable emissions constraints," 76 FR at 48230, EPA mandated emissions budgets for 2014 based on the assumption that action was still required under §110(a)(2)(D)(i)(I), *see id.* at 48261-63. It had no basis for doing so. *See Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (requiring a "'rational connection between the facts found and the choice made'" (citation omitted)).

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[28] For example, of the 16 individual receptors that EPA predicted would be in nonattainment for the 2012 base case for annual $PM_{2.5}$, EPA predicted that nine would achieve attainment in 2014 in the absence of any CAIR or CSAPR emissions controls. *See* Air Quality TSD at B35-63 (JA2580-608) (2014 base case design values for the sites identified at Significant Contribution TSD at 35 (JA2964) relative to 15 $\mu g/m^3$ NAAQS attainment threshold). EPA also similarly predicted that the attainment and maintenance problems it predicted in 2012 for many 8-hour ozone and 24-hour $PM_{2.5}$ receptors would be resolved in 2014 even in the absence of any CAIR or CSAPR emission limits, *compare* 76 FR at 48246 (listing projected nonattainment and maintenance receptors for 8-hour ozone), *with* Air Quality TSD at B1-34 (JA2546-79) (providing 2014 base case design values for these receptors relative to 85 ppb NAAQS attainment threshold); *compare* 76 FR at 48242-44 (listing projected nonattainment and maintenance receptors for 24-hour $PM_{2.5}$), *with* Air Quality TSD at B4-92 (JA2549-637) (providing 2014 base case design values relative to 35 $\mu g/m^3$ NAAQS attainment threshold).

Nor did EPA's 2012 base case projections provide a reasoned basis for imposing CSAPR in 2012. As EPA recognized, the attainment dates for the relevant NAAQS are not until well after 2012 for some downwind States. *See* 76 FR at 48279; *see also* Int'l Brotherhood of Boilermakers Comments, EPA-HQ-OAR-2009-0491-2672, at 5-6 (JA818-19). For example, as EPA acknowledged, Houston has until 2019 to comply with ozone attainment obligations, 76 FR at 48277, 48279, and EPA's own modeling shows that the maintenance receptors linking Florida and South Carolina to Houston will no longer have any maintenance issues by 2014—even without imposition of CSAPR or related reductions. *See* Air Quality TSD at B30-31 (JA2575-76) (receptors 482010029 and 482011050).[29] Similarly, as EPA recognized, the attainment deadline for 24-hour $PM_{2.5}$ NAAQS considered in CSAPR is not until December 2014, *see* 76 FR at 48277, 48279, but EPA projects many of those locations would achieve attainment by then even absent CSAPR, *see supra* n.28. And while the presumptive attainment date for the annual $PM_{2.5}$ NAAQS considered in CSAPR has passed, EPA has statutory extension authority and has used it to grant an extension to 2015 for the one location (Allegheny County, Pennsylvania) that cannot currently satisfy that NAAQS. *See generally* 76 FR 68699.

Ultimately, imposition of CSAPR in 2012 is inconsistent with EPA's own analysis and findings. *Bus. Roundtable v. SEC*, 647 F.3d 1144, 1153 (D.C. Cir. 2011)

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[29] These receptors are the sole basis for Florida and South Carolina's inclusion in CSAPR's seasonal NO_X program. *See* 76 FR at 48246.

(reversing as arbitrary "internally inconsistent" agency analysis). EPA itself justified the cost thresholds used to set emissions budgets solely by reference to the air quality results that would be achieved in 2014, *not* 2012. *See* 76 FR at 48255 (justifying cost curves based on "estimated air quality impacts in 2014"). EPA did not analyze the air quality that would be achieved in 2012 as a result of its emissions budgets, *see id.*, let alone find that its emissions budgets could be justified on the basis of 2012 air quality improvements. Thus, regardless of the attainment dates for the NAAQS considered by EPA in CSAPR, EPA did not—and could not—justify its proposed emissions limits on the basis of the air quality those limits would achieve in 2012. And because EPA made no findings for 2013 and its findings for 2014 demonstrate that many areas at issue would achieve attainment absent transport regulation, there is simply no reasonable basis upon which CSAPR can be imposed.

V. EPA'S METHOD FOR DETERMINING STATE EMISSIONS BUDGETS WAS ARBITRARY AND CAPRICIOUS.

EPA's application of IPM to develop State emissions budgets was also arbitrary. EPA developed State emission budgets by aggregating unit-level emission predictions generated by IPM for the covered power plants within a State, even though EPA *knew* that IPM does *not* accurately predict generation and emissions at the unit level. Primary Response to Comments at 2107 (JA2089) ("there will be discrepancies between IPM unit level projections and a unit's actual future operations due to non-economic or other variables that IPM does not capture.").[30] EPA simply assumed that unit-level flaws would disappear when aggregated at the State level. *Id.* at 1058 (JA2047) ("At the state and regional level, the discrepancies are small and random and thus do not result in biases."). This assumption was arbitrary and incorrect. EPA failed to demonstrate that its "model assumptions … have a 'rational relationship' to the real world." *Appalachian Power Co.*, 249 F.3d at 1053 (citation omitted).

EPA was fully aware that key methodological constraints introduced significant errors into the model. For example, "[w]ithin each model region, IPM *assumes* that adequate transmission capacity exists to deliver any resources located in, or transferred to, the region." Reliability TSD at 2 (JA2919) (emphasis added).[31] In plain terms, EPA assumes that electricity generated within a region can travel to anywhere in that region, unimpeded by transmission constraints and, therefore, the model allows the dispatch of low-emitting units wherever they are located within the region. In the real world, power is dispatched economically and is constrained by

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[30] *See, e.g.*, Southern Comments at 25-26 (JA1366-67); LCA Comments, EPA-HQ-OAR-2009-0491-3527, at 40-44 and Exhibits 10-12 (JA1427-31, 1439-69).

[31] *See, e.g.*, Northeast States for Coordinated Air Use Management Comments, ("NESCAUM Comments"), EPA-HQ-OAR-2009-0491-2694, at 6 (JA830); Independence Power & Light Comments, EPA-HQ-OAR-2009-0491-2741, at 12 (JA970); Entergy Comments, EPA-HQ-OAR-2009-0491-2847, at 3 (JA1311) ("Entergy Comments").

intraregional load pockets,[32] voltage requirements,[33] and local reliability requirements.[34] These constraints often require the dispatch of older, higher-emitting units that IPM predicts are shut off as noneconomic.[35]

Similarly, IPM is not capable of accurately modeling steam production by cogeneration units.[36] IPM predicts cogeneration unit operation based only on *electricity* demand, but does not account for unit operation required to meet steam demand.[37] As a result, cogeneration unit emissions projected by IPM are significantly lower than their actual emissions. Base Case v4.10 Supplement at 2 (JA2770). EPA's attempt to compensate for this defect by applying a multiplier to the "power only emissions" does not address the fundamental problem that IPM is incapable of predicting steam generation and, thus, erroneously predicts that many cogeneration units will not

[32] A load pocket is an area with units that must run, often because power cannot be imported into the area to meet demand. *See*, *e.g.*, Mirant Comments, EPA-HQ-OAR-2009-0491-2843, at 13 (JA1306).

[33] Voltage requirements are requirements to maintain grid voltage at prescribed levels. *See, e.g.*, Entergy Comments at 3 (JA1311).

[34] Certain areas, like the Northeast, have local reliability constraints that are not accounted for in the model. *See, e.g.*, NESCAUM Comments at 6 (JA830).

[35] *See, e.g.*, Westar Comments, EPA-HQ-OAR-2009-0491-2757, at 18-22 (JA1208-12). EPA, however, opted to "retain[] the current approach that does not attempt to account for 'must run' units." Documentation Supplement for EPA Base Case v.4.10_Ftransport-Updates for Final Transport Rule, at 52 (JA2820).

[36] Cogeneration units are units which generate both electricity, which can be used on-site or dispatched on the electricity grid, and steam for industrial or institutional use.

[37] *See* NESCAUM Comments at 6 (JA830); Con Edison Comments, EPA-HQ-OAR-2009-2653, at 2, 9 (JA597, 604)("Con Edison Comments").

operate at all.[38] Even with an emissions multiplier, IPM still incorrectly predicts zero emissions from these units.

EPA's failure to model such constraints introduced serious error into the IPM results and produced significantly flawed budgets. Just as in *Columbia Falls Aluminum Co. v. EPA*, "EPA knows that 'key assumptions' underlying the [model] are wrong and yet has offered no defense of its continued reliance on it." 139 F.3d 914, 923 (D.C. Cir. 1998). EPA's knowing use of a flawed model cannot stand.

EPA should (and could) have taken the necessary step of testing its model results against real-world data.[39] *See Jackson*, 650 F.3d at 665-66. It did not. EPA failed to heed obvious signs that the IPM predictions were inaccurate. In many cases, IPM's base case predictions, which purport to represent each State's emissions in 2012 without CAIR or CSAPR emission reductions, were *substantially lower* than recent actual emissions. For example, the base case 2012 ozone season NO_X emissions projections for Louisiana and Illinois were 42% and 24% below actual 2010 ozone

[38] Con Edison Comments at 8-11 (JA603-06) (explaining that while certain Con Edison units must run to provide steam service in New York City, IPM predicts that they will not run for electric service and therefore erroneously predicts no emissions from the units).

[39] Indeed, at the proposal stage, EPA even admitted that historic emissions data was a more accurate basis for estimating future emissions. *See* 75 FR at 45290 ("EPA believes that the actual performance units achieved in 2009 is more representative of expected emissions than what EPA modeled using IPM.").

season NO_X emissions, respectively.[40] IPM also predicted implausible emission reductions. For example, IPM predicted an astounding reduction in Texas's actual SO_2 emissions of 461,662 tons in 2010 to 243,954 in 2012 after implementation of CSAPR.[41] These red flags should have alerted EPA to test its IPM predictions against real-world data.

Ultimately, there is no question that IPM's outputs are flawed; EPA has conceded in the Error Corrections Notice that its emission budgets contain numerous errors. 76 FR at 63862. There, EPA arithmetically adjusted IPM outputs (*i.e.,* the emissions predicted at specific units) to address certain unit-specific errors (*e.g.,* a unit must run more than IPM predicted), but did not make any adjustments to IPM itself. These limited adjustments dramatically change several state budgets,[42] demonstrating that unit-level errors can be significant enough by themselves to result in flawed budgets.[43]

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[40] *Compare* State Historic Emission - TR Budget, EPA-OAR-2009-0491-4136, at 2 (Actual Emissions) (JA3498), *with* Significant Contribution TSD at 10 (Base Case Projections) (JA2939).

[41] *See* State Historic Emission - TR Budget at 1 (JA3497).

[42] C*ompare* 76 FR at 48414 (seasonal NO_X budgets) *and* 48466 (SO_2 Group 2 budgets), *with* 76 FR at 63875 (proposed revised seasonal NO_X budgets) *and* 63877-78 (proposed revised SO_2 Group 2 budgets).

[43] Importantly, EPA has not fixed and re-run IPM. *See* 76 FR at 63862. Rather, EPA has utilized a piecemeal approach to address inaccuracies at only a fraction of the units affected by CSAPR. EPA's Error Correction Notice does not address, much less cure, the methodological flaws in IPM. Without a sound methodology, there can be no assurance that EPA's band-aid fixes do not also produce flawed results. (Petitioners have not yet had an opportunity to analyze fully the implications

Because a model is only as good as its assumptions, EPA "retains a duty to examine key assumptions as part of its affirmative 'burden of promulgating and explaining a non-arbitrary, non-capricious rule.'" *Small Refiner Lead Phase-Down Task Force v. U.S. EPA*, 705 F.2d 506, 534 (D.C. Cir. 1983) (citation omitted). EPA's failure to do so here was arbitrary and capricious. *See Appalachian Power Co.*, 249 F.3d at 1054 (EPA failed to "'examine the relevant data and articulate a satisfactory explanation for its action.'" (citation omitted)).

VI. CSAPR'S COMPLIANCE SCHEDULE IS ARBITRARY AND CAPRICIOUS.

CSAPR's infeasible deadlines compound the rule's arbitrariness and provide an independent reason for vacatur. EPA has admitted that sources could comply with its deadlines only if they undertook costly controls *before* CSAPR's issuance. 76 FR at 48281, 48283.[44] That is arbitrary—particularly because EPA made dramatic changes between the proposed and final rules, including adding States to and removing them

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of EPA's final Error Corrections Rule, as that rule was released less than two days before this brief was due, but whatever fixes EPA made to individual units, they did not even purport to fix IPM's methodological errors, or to re-run the model). EPA, therefore, cannot rely on the Error Corrections Notice to defend its arbitrary methodology for establishing state budgets. *See AT&T Co. v. FCC*, 978 F.2d 727, 731-32 (D.C. Cir. 1992) (agencies cannot "avoid judicial review" by engaging in "a sort of administrative law shell game").

[44] CAIR and the NO_X SIP Call allowed enough time to install controls. 70 FR at 25216 (over 43 months for NO_X and 55 months for SO_2 reductions in CAIR); 63 FR at 57366 (54 months for NO_X reductions in NO_X SIP Call). In contrast, CSAPR's first compliance period begins less than 5 months after its publication, and additional requirements apply 24 months thereafter.

from the rule and changing budgets. EPA tries to justify its deadlines as necessary to achieve "expeditious[]" NAAQS attainment on a "practicable" schedule, s*ee, e.g.*, 76 FR at 48278, and to "align[]" with NAAQS-attainment dates, *id.* at 48277-79. But that reasoning cannot stand.

EPA implausibly claimed the first-phase budgets can be achieved by the beginning of 2012: for SO_2, through "optimize[d]" operation of existing or scheduled controls; switching to lower-sulfur coal; and shifting generation to lower-emitting units; and, for NO_X, through year-round operation of already-in-place or already-scheduled controls, enhancing existing controls' performance, fuel-switching, and installing ("retrofitting") low-NO_X burners (LNB) or selective noncatalytic reduction (SNCR) equipment. *Id.* at 48280. EPA contended sources could, if all else fails, buy allowances. *Id.*

As commenters explained, these conclusions were wrong. For example, EPA admits LNB installations are needed to achieve up to 11% of the reductions individual States must achieve to meet their 2012 annual NO_x budgets. 76 FR at 48281. However, LNB retrofits have typically taken around 18 months to complete, far longer than the EPA-assumed 6 months. UARG Comments at 45-46 (JA1041-42); *id.*, Att. I at 4-2 (Fig. 4-2), 4-5 to 4-6 (JA1123, 1126-27) ("Cichanowicz Report"). In response, EPA conceded that its assumed 6-month LNB retrofit schedule was "aggressive" and could be met only by "some units" and "under favorable circumstances," and that "a more typical" LNB-retrofit schedule was "12 to 16 months for the contractor's portion of the work," preceded by "several additional months" of advance planning and procurement. 76 FR at 48281. Nevertheless, EPA refused to adjust its 2012 deadline or budgets.

Similarly, while recognizing sources would have to install massive scrubbers and SCR equipment to meet CSAPR's SO_2 and NO_x reduction levels by the 2014 deadline, EPA assumed it would take only 27 months to retrofit scrubbers to reduce SO_2, and only 21 months for NO_x-reducing SCR retrofits.[45] *See id.* at 48282. Commenters had explained that these retrofits typically take about 40-60 months or more for scrubbers and 28-50 months or more for SCR. UARG Comments at 27-47 (JA1023-43); Cichanowicz Report at 3-1 to 4-5 (JA1115-26). EPA did not dispute commenters' timelines and effectively conceded error just two weeks after CSAPR's publication. 76 FR 52388, 52408 (Aug. 22, 2011) (concluding the Cichanowicz Report "*confirm[ed]*" results of "independent [EPA] investigation" finding median and average SCR-installation schedules are 33 and 37 months) (emphasis added).[46]

EPA also assumed, based in part on selective information from *brand-new* units,[47] that "retrofits [of *existing* units] can be completed far more quickly than they

[45] EPA assumed the 2012 deadline "would not allow for the installation of … SCR," 76 FR at 48280, implicitly assuming 2014 compliance would entail SCR installations.

[46] EPA also acknowledged a longer-than-average schedule is necessary for some units "due to site-specific issues such as the congestion of existing equipment." 76 FR at 52391.

[47] *See* 76 FR at 48282 (discussing EPA reliance on selective information from new units).

were in recent history." *Id.* at 48282. But commenters explained that in fact (1) recent retrofits have taken *longer* on average, partly because easier retrofits were done first, Cichanowicz Report at 5-1 to 5-5 (JA1128-32); and (2) numerous unit-specific, physical constraints complicate existing-unit installations.[48] Commenters also explained that CSAPR's deadlines, both alone and in conjunction with numerous concurrent EPA regulations affecting electric generators,[49] threaten to destabilize electricity grids generally and in specific locations.[50] Because CSAPR's compressed schedule could require units being retrofitted to go off-line simultaneously, it would threaten outages.[51] Other units, for which control installation is infeasible, could be

[48] *See* 76 FR at 52391, 52408-09 (promulgating FIP with longer-than-average compliance schedule based on site-specific constraints); *see also* UARG Comments at 38-41 (JA1034-37); Cichanowicz Report at 5-1 to 5-5 (JA1128-32).

[49] EPA-HQ-OAR-2009-0491-2658, at 4-5 (JA645-46); EPA-HQ-OAR-2009-0491-2855, at 3 (JA1329).

[50] *E.g.*, EPA-HQ-OAR-2009-0491-2733, at 2-3 (JA930-31); EPA-HQ-OAR-2009-0491-2700, at 1-4 (JA834-37); EPA-HQ-OAR-2009-0491-2629, at 6 (JA573); EPA-HQ-OAR-2009-0491-3807, at 2 (JA1471); EPA-HQ-OAR-2009-0491-2762, at 3 (JA1215).

[51] *See, e.g.,* EPA-HQ-OAR-2009-0491-2715, at 14 (JA912); EPA-HQ-OAR-2009-0491-2797, at 3 (JA1246); EPA-HQ-OAR-2009-0491-2657, at 6 (JA615); EPA-HQ-OAR-2009-0491-2752, at 7 (JA988); EPA-HQ-OAR-2009-0491-2793.2, at 3-4 (JA1233-44). For example, Wisconsin Electric Power Co. typically is required to operate four of the five units at Presque Isle Power Plant in Michigan's Upper Peninsula to avoid threats to system voltage and stability stemming from local transmission-system constraints. EPA-HQ-OAR-2009-0491-2629, at 6 (JA573). Absent control installations that cannot be completed before spring 2014, the plant could not meet this operational requirement without exceeding CSAPR allocations. *Id.*

forced to close.[52] And even if sufficient generation were available, transmission constraints, or "congestion," threaten reliability.[53] EPA conceded that it had failed to consider "local grid issues" such as "shifts in congestion patterns and transmission impacts from the retirement of specific power plants" resulting from CSAPR, which would remain to be addressed "at the utility and regional levels."[54]

Furthermore, while Congress and EPA in prior cap-and-trade programs (*e.g.*, the 1990 CAA Acid Rain Program, the NOx SIP Call, and CAIR) gave power plants 3-5 years to meet the initial "cap" so that they had the option of installing controls or purchasing allowances, CSAPR imposes more stringent caps and gives companies virtually no time to install new controls. As a result, according to EPA, CSAPR compliance is to be achieved, in part, almost immediately by "shifting generation … to lower-emitting units." 76 FR at 48280. This approach penalizes companies that complied with prior cap-and-trade programs by purchasing allowances.

When companies objected to EPA's unprecedented approach, the agency did not dispute the comments on control retrofits, grid reliability impacts or compliance schedules. EPA responded that CSAPR's deadlines were "practicable" because, it said, sources should have begun retrofits based solely on EPA's *proposed* rule. 76 FR at

[52] *E.g.,* EPA-HQ-OAR-2009-0491-3845, at 2 (JA1474); EPA-HQ-OAR-2009-0491-3807, at 2 (JA1471); EPA-HQ-OAR-2009-0491-2762, at 3 (JA1215).

[53] EPA-HQ-OAR-2009-0491-2740, at 18 (JA953); EPA-HQ-OAR-2009-0491-2741, at 12-13 (JA970-71); EPA-HQ-OAR-2009-0491-2757, at 19 (JA1209).

[54] Primary Response to Comments at 1517, 1526 (JA2076, 2085).

48281, 48283. According to EPA, it "expect[ed] … *advance planning* ha[d] already been done"—*before* CSAPR's promulgation—to enable compliance once CSAPR took effect. *Id.* at 48283 (emphasis added). Indeed, EPA thinks "it is reasonable … to expect that utilities would have commenced advanced planning efforts for potential cost-effective retrofits, including contract negotiations and bid evaluations," well before CSAPR was promulgated. Engineering Feasibility Response to Comments at 5 (JA2117).

But just as EPA lacks authority to promulgate retroactive rules, *cf. Bowen v. Georgetown Univ. Hosp.*, 488 U.S. 204, 208 (1988), EPA cannot justify setting extraordinarily tight deadlines by asserting after the fact that sources should have anticipated and begun to comply with a rule years before it was promulgated and takes effect. EPA's reasoning is especially arbitrary here, where changes to state budgets, and even *which* States are regulated, were so substantial that OMB concluded CSAPR was "a significantly different rule than originally proposed." OMB Comments at 11 (JA3493). Indeed, EPA's final Error Corrections Rule—released less than 48 hours ago, and more than a month *after* CSAPR was set to take effect—makes substantial changes to numerous state budgets.[55] That CSAPR's requirements are still in flux—even after it was supposed to take effect, and especially given that emission controls

[55] This release included *two* final rules, one of which is a direct final rule (*i.e.*, one in which no comment opportunity has yet been given, and which will be converted to a proposed rule if adverse comments are received). For this reason, CSAPR's requirements are still in flux today and will remain so for some time.

must be engineered to meet the specific limitations selected in the final rule—merely underscores the unreasonable and arbitrary nature of EPA's demand that sources begin complying with a major regulation before it is final.

Finally, NAAQS-attainment deadlines provide no justification for CSAPR's accelerated schedule. As explained in §IV.C., EPA failed to show CSAPR's schedule is compelled by a need to align with attainment deadlines applicable in downwind areas intended to be addressed by CSAPR.

EPA's unreasonable compliance deadlines therefore provide an independent basis for vacating CSAPR. For the reasons discussed above, CSAPR is unauthorized by the CAA and unlawful. But even when an agency is actually authorized to promulgate the substantive requirements at issue, its compliance schedule must be reasonable and in accordance with law. CSPAR flunks that additional, common-sense prerequisite for valid agency action as well.

CONCLUSION

For the foregoing reasons, CSAPR should be vacated.

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Respectfully submitted,

/s/ Peter D. Keisler
Peter D. Keisler
Roger R. Martella, Jr.
C. Frederick Beckner III
Timothy K. Webster
R. Juge Gregg
Sidley Austin LLP
1501 K Street, NW
Washington, DC 20005
(202) 736-8000
pkeisler@sidley.com

F. William Brownell
Hunton & Williams LLP
2200 Pennsylvania Avenue, NW
Washington, DC 20037
(202) 955-1500
bbrownell@hunton.com

Counsel for Petitioners Luminant Generation Company LLC et al.

Gregory G. Garre
Claudia M. O'Brien
Lori Alvino McGill
Jessica E. Phillips
Katherine I. Twomey
Stacey VanBelleghem
Latham & Watkins LLP
555 Eleventh Street, NW
Suite 1000
Washington, DC 20004-1304
(202) 637-2200
gregory.garre@lw.com

Counsel for Petitioner EME Homer City Generation, LP

Janet J. Henry, Deputy General Counsel
American Electric Power Service Corp.
1 Riverside Plaza
Columbus, OH 43215
(614) 716-1612
jjhenry@aep.com

Counsel for Petitioners AEP Texas North Co., Appalachian Power Co., Columbus Southern Power Co., Indiana Michigan Power Co., Kentucky Power Co., Ohio Power Co., Public Service Co. of Oklahoma, Southwestern Electric Power Co.

William M. Bumpers
Joshua B. Frank
Megan H. Berge
Baker Botts LLP
1299 Pennsylvania Avenue, NW
The Warner, Suite 1300 West
Washington, DC 20004-2400
(202) 639-7700
william.bumpers@bakerbotts.com

Counsel for Petitioners Consolidated Edison Company of New York, Inc., Entergy Corp., Northern States Power Co. – Minnesota, Southwestern Public Service Co., Western Farmers Electric Cooperative

Steven G. McKinney
Balch & Bingham LLP
1901 Sixth Avenue North
Suite 1500
Birmingham, AL 35203-4642
(205) 251-8100
smckinney@balch.com

Counsel for Petitioner Alabama Power Co.

P. Stephen Gidiere, III
Balch & Bingham LLP
1901 Sixth Avenue North
Suite 1500
Birmingham, AL 35203-4642
(205) 251-8100
sgidiere@balch.com

Counsel for Petitioner Luminant Generation Company LLC et al.

Terese T. Wyly
Balch & Bingham LLP
1310 Twenty Fifth Avenue
Gulfport, MS 39501-1931
(228) 864-9900
twyly@balch.com

Counsel for Petitioner Mississippi Power Co.

Richard Alonso
Jeffrey R. Holmstead
Bracewell & Giuliani LLP
2000 K Street, NW, Suite 500
Washington, DC 20006-1872
(202) 828-5800
richard.alonso@bgllp.com

Counsel for Petitioner GenOn Energy, Inc.

Gary C. Rikard
Butler, Snow, O'Mara, Stevens & Cannada, PLLC
6075 Poplar Avenue
Fifth Floor
Memphis, TN 38119
(901) 680-7200
gary.rikard@butlersnow.com

Counsel for Petitioner South Mississippi Electric Power Association

Robert J. Alessi
Dewey & LeBoeuf LLP
99 Washington Avenue
Suite 2020
Albany, NY 12210
(518) 626-9400
ralessi@dl.com

Counsel for Petitioner Environmental Energy Alliance of New York, LLC

Chuck D'Wayne Barlow,
Assoc. General Counsel
Entergy Services, Inc.
PO Box 1640
Jackson, MS 39215-0000
(601) 969-2542
cbarlow@entergy.com

Counsel for Petitioner Entergy Corp.

Peter P. Garam
Consolidated Edison Company of New York, Inc.
Room 1815-S
4 Irving Place
New York, NY 10003
(212) 460-2985
garamp@coned.com

Counsel for Petitioner Consolidated Edison Company of New York, Inc.

Kyra Marie Fleming, Deputy General Counsel
DTE Energy Resources, Inc.
414 South Main Street
Suite 600
Ann Arbor, MI 48104
(734) 302-4898
flemingk@dteenergy.com

Counsel for Petitioner DTE Stoneman, LLC

Richard G. Stoll
Brian H. Potts
Julia L. German
Foley & Lardner LLP
3000 K Street, NW, 6th Floor
Washington, DC 20007-5143
(202) 672-5300
rstoll@foley.com

Counsel for Petitioner Wisconsin Public Service Corp.

Robert A. Manning
Joseph A. Brown
Mohammad O. Jazil
Hopping Green & Sams, P.A.
119 South Monroe Street
Suite 300
Tallahassee, FL 32301
(850) 222-7500
robertm@hgslaw.com

Counsel for Petitioner Environmental Committee of the Florida Electric Power Coordinating Group, Inc.

James S. Alves
Gary V. Perko
Hopping Green & Sams, P.A.
119 South Monroe Street
Suite 300
Tallahassee, FL 32301
(850) 222-7500
jalves@hgslaw.com

Counsel for Petitioner Gulf Power Co.

Eric J. Murdock
Hunton & Williams LLP
2200 Pennsylvania Avenue, NW
Washington, DC 20037
(202) 955-1500
emurdock@hunton.com

Counsel for Petitioner DTE Stoneman, LLC

William L. Wehrum, Jr.
Hunton & Williams LLP
2200 Pennsylvania Avenue, NW
Washington, DC 20037
(202) 955-1500
wwehrum@hunton.com

Counsel for Petitioner National Rural Electric Cooperative Association

Andrea Bear Field
Norman W. Fichthorn
E. Carter Chandler Clements
Hunton & Williams LLP
2200 Pennsylvania Avenue, NW
Washington, DC 20037
(202) 955-1500
afield@hunton.com

Counsel for Petitioner Utility Air Regulatory Group

David M. Flannery
Gale Lea Rubrecht
Jackson Kelly PLLC
500 Lee Street East, Suite 1600
PO Box 553
Charleston, WV 25322-0553
(304) 340-1000
dmflannery@jacksonkelly.com

Counsel for Petitioner Midwest Ozone Group

Maureen N. Harbourt
Kean Miller LLP
PO Box 3513
Baton Rouge, LA 70821
(225) 387-0999
maureen.harbourt@keanmiller.com

Tokesha M. Collins
Kean Miller LLP
400 Convention Street
Suite 700
Baton Rouge, LA 70816
(225) 382-3426
tokesha.collins@keanmiller.com

Counsel for Petitioners Lafayette Utilities System and Louisiana Chemical Association

William F. Lane
Kilpatrick Townsend & Stockton LLP
4208 Six Forks Road
Suite 1400
Raleigh, NC 27609
(919) 420-1700
blane@kilpatricktownsend.com

Counsel for Petitioner CPI USA North Carolina LLC

Bart E. Cassidy
Katherine L. Vaccaro
Diana A. Silva
Manko, Gold, Katcher & Fox, LLP
401 City Avenue
Suite 500
Bala Cynwyd, PA 19004
(484) 430-5700
bcassidy@mgkflaw.com

Counsel for Petitioners ARIPPA and Sunbury Generation LP

Jordan Hemaidan
Todd Palmer
Michael Best & Freidrich LLP
One South Pinckney Street
Suite 700
Madison, WI 53705
(608) 283-4431
jjhemaidan@michaelbest.com

Counsel for Petitioners Midwest Food Processors Association, Wisconsin Cast Metals Association, Wisconsin Manufacturers and Commerce, and Wisconsin Paper Council, Inc.

Douglas E. Cloud
David Meezan
Christopher Max Zygmont
Mowrey Meezan Coddington Cloud LLP
1100 Peachtree Street
Suite 650
Atlanta, GA 30309
(404) 969-0740
doug.cloud@m2c2law.com

Counsel for Petitioner Municipal Electric Authority of Georgia

Gary M. Broadbent
Murray Energy Corp.
56854 Pleasant Ridge Road
Allendonia, OH 43902
(740) 926-1351
gbroadbent@coalsource.com

Michael O. McKown, General Counsel
Murray Energy Corp.
29325 Chagrin Blvd, Suite 300
Pepper Pike, OH 44122
(216) 765-1240
mmckown@coalsource.com

Counsel for Petitioners American Coal Co., American Energy Corp., Kenamerican Resources, Inc., Murray Energy Corp., Ohio American Energy, Inc., Ohio Valley Coal Co., and UtahAmerican Energy, Inc

Matthew J. Splitek
Donald K. Schott
Quarles & Brady LLP
33 East Main Street, Suite 900
Madison, WI 53703-3095
(608) 283-2454
matthew.splitek@quarles.com

Cynthia A. Faur
Quarles & Brady LLP
300 N. LaSalle Street, Suite 4000
Chicago, IL 60654-3406
(312) 715-5228

Counsel for Petitioner Wisconsin Electric Power Co.

Terry Russell Yellig
Sherman, Dunn, Cohen, Leifer & Yellig, PC
900 7th Street, NW
Suite 1000
Washington, DC 20001
(202) 785-9300
yellig@shermandunn.com

Counsel for Petitioner International Brotherhood of Electrical Workers, AFL-CIO

Dennis Lane
Stinson Morrison Hecker, LLP
1775 Pennsylvania Avenue, NW
Suite 800
Washington, DC 20006
(202) 785-9100
dlane@stinson.com

Counsel for Petitioners Kansas City Board of Public Utilities, Unified Government of Wyandotte County, Kansas City, Kansas, Kansas Gas and Electric Co., Sunflower Electric Power Corp., and Westar Energy, Inc.

Margaret Claiborne Campbell
Byron W. Kirkpatrick
Hahnah Williams
Troutman Sanders LLP
600 Peachtree Street, NE
5200 Bank of America Plaza
Atlanta, GA 30308-2216
(404) 885-3000
margaret.campbell@troutmansanders.co
m

Counsel for Petitioners Georgia Power Co., Southern Co. Services, Inc., and Southern Power Co.

Karl R. Moor
Julia A. Bailey Dulan
Southern Company Services, Inc.
600 North 18th Street
Bin 15N-8190
Birmingham, AL 35203
(205) 251-6227
krmoor@southernco.com

Counsel for Petitioner Southern Co. Services, Inc.

Peter S. Glaser
Tameka M. Collier
Troutman Sanders LLP
401 9th Street, NW, Suite 1000
Washington, DC 20004-2134
((202) 274-2950
peter.glaser@troutmansanders.com

Counsel for Petitioners National Mining Association and Peabody Energy Corp.

Grant F. Crandall
Arthur Traynor, III
United Mine Workers of America
18354 Quantico Gateway Drive
Suite 200
Triangle, VA 22172
(703) 291-2429
gcrandall@umwa.org

Eugene M. Trisko
Law Offices of Eugene M. Trisko
PO Box 47
Glenwood, MD 21738
(301) 639-5238
emtrisko7@gmail.com

Counsel for Petitioner United Mine Workers of America

Elizabeth P. Papez
John M. Holloway III
Elizabeth C. Williamson
Winston & Strawn, LLP
1700 K Street, NW
Washington, DC 20006-3817
(202) 282-5000
epapex@winston.com

Counsel for Petitioner East Kentucky Power Cooperative, Inc.

Jeffrey L. Landsman
Vincent M. Mele
Wheeler, Van Sickle & Anderson, S.C.
25 West Main Street
Suite 801
Madison, WI 53703-3398
(608) 255-7277
jlandsman@wheelerlaw.com

Counsel for Petitioner Dairyland Power Cooperative

Ann M. Seha
Assistant General Counsel
XCEL ENERGY INC.
414 Nicollet Mall
5th Floor
Minneapolis, MN 55401
(612) 215-4582
ann.m.seha@xcelenergy.com

Counsel for Petitioners Northern States Power Co. – Minnesota, and Southwestern Public Service Co.

CERTIFICATE OF COMPLIANCE

In accordance with Circuit Rule 32(a) and Rule 32(a)(7) of the Federal Rules of Appellate Procedure, the undersigned certifies that the accompanying brief has been prepared using 14-point Garamond Roman typeface, and is double-spaced (except for headings and footnotes).

The undersigned further certifies that the brief is proportionally spaced and contains 14,337 words exclusive of the certificate required by Circuit Rule 28(a)(1), table of contents, table of authorities, glossary, signature lines, and certificates of service and compliance. The combined words of the Industry and Labor Petitioners' Brief and the State and Local Petitioners' Opening Brief do not exceed 28,000 words, as mandated by this Court's January 18, 2012 Order. Dkt. 1353334. The undersigned used Microsoft Word 2007 to compute the count.

/s/ Peter D. Keisler
Peter D. Keisler

CERTIFICATE OF SERVICE

I hereby certify that on this 16th day of March, 2012, I electronically filed the foregoing Final Brief of Industry and Labor Petitioners and accompanying addenda with the Clerk of the Court using the CM/ECF System, which will send notice of such filing to all registered CM/ECF users.

Pursuant to D.C. Circuit Rules 25 and 31, and the Court's Order of January 26, 2012, nine (9) paper copies of the foregoing brief and accompanying addenda will be hand-delivered to the Clerk of the Court.

I further certify that some of the participants in the case are not registered CM/ECF users. I have caused two copies of the foregoing brief and accompanying addenda to be sent by U.S. first-class mail to the following non-CM/ECF participants:

Kimberly P. Massicotte
Office of the Attorney General
State of Connecticut
55 Elm Street
Hartford, CT 06106

Thomas M. Fisher,
Office of the Attorney General
State of Indiana
Indiana Government Center South
Fifth Floor
302 West Washington Street
Indianapolis, IN 46204-2770

Jonathan A. Glogau
Office of the Attorney General
State of Florida
The Capitol, Suite PL-01
Tallahassee, FL 32399-1050

William H. Sorrell
Office of the Attorney General
State of Vermont
109 State Street
Montpelier, VT 05609-1001

James C. Gulick
North Carolina Department of Justice
P.O. Box 629
Raleigh, NC 27602-0629

Jon Cumberland Bruning
Office of the Attorney General
State of Nebraska
2115 State Capitol
PO Box 98920
Lincoln, NE 68509-8920

Sonja Lynn Rodman
U.S. Environmental Protection Agency (EPA)
Office of General Counsel
1200 Pennsylvania Avenue, NW
Ariel Rios Building
Washington, DC 20460-0000

Gregory Wayne Abbott
Office of the Attorney General
State of Texas
PO Box 12548
Austin, TX 78711-2548

Herman Robinson
Jackie Marie Scott Marve
Louisiana Department of Environmental Quality
602 North Fifth Street
Baton Rouge, LA 70802

Luther J. Strange, III
Office of the Attorney General
State of Alabama
501 Washington Avenue
Montgomery, AL 36104

Douglas Friend Gansler
Assistant U.S. Attorney
Office of the Attorney General
State of Maryland
200 St. Paul Place, 20th Floor
Baltimore, MD 21202-2021

Chris Kim
Gregg Henry Bachmann
Office of the Attorney General
State of Ohio
Environmental Enforcement Section
30 East Broad Street
25th Floor
Columbus, OH 43215-3400

/s/ Peter D. Keisler
Peter D. Keisler

ADDENDUM
PURSUANT TO CIRCUIT RULE 28(a)(7)

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IN THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA

EME HOMER CITY GENERATION, L.P., *Petitioner*, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY AND LISA P. JACKSON, ADMINISTRATOR, *Respondents*.	))))))))))))))	Case No. 11-1302

<u>DECLARATION OF DOUGLAS R. MCFARLAN</u>

I, Douglas R. McFarlan, do hereby declare under the penalty of perjury, pursuant to 28 U.S.C. §1746, as follows:

1. I am President of Mission Energy Westside Inc., the general partner of EME Homer City Generation, L.P., a Pennsylvania limited partnership which owns the Homer City Generating Plant in Pennsylvania. I am also Senior Vice President, Public Affairs for Edison Mission Group, the indirect parent company of Mission Energy Westside Inc. In that role, I am responsible for state and local government relations, environmental policy and compliance, media and community relations, executive and employee communications, and corporate contributions. I joined the company in 1999 and became President

of Mission Energy Westside Inc. in 2011. I am a board member of the Electric Power Supply Association, past chairman of the Electric Power Generators Association in Harrisburg, Pennsylvania, board member and founding chairman of the Illinois State Chamber of Commerce Energy Council, a board member of the Independent Energy Producers of California, and a member of numerous committees of the Illinois Energy Association. This declaration is made in support of Petitioner's Motion for a Stay, or In the Alternative, Expedited Review.

2. I have personal knowledge of the issues and activities referred to herein, except where stated on information and belief. If called upon to testify, I could and would testify truthfully thereto.

3. The purpose of this declaration is to explain the irreparable harm that will result to petitioner if EPA's rule, "Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals," 76 Fed. Reg. 48,208 (Aug. 8, 2011) ("Transport Rule"), is permitted to take effect, and my belief that a stay of the effective date of the Transport Rule pending this Court's review, or expedited briefing in the alternative, is needed to prevent this harm.

Background on EME Homer City Generation, L.P.

4. EME Homer City Generation, L.P. ("EME Homer City") is an indirect subsidiary of Edison Mission Energy, LLC ("EME"), an independent power

producer engaged in the business of developing, acquiring, owning or leasing, capacity to generate and sell electricity into the wholesale energy market. EME Homer City and EME are part of the Edison International family of companies. EME owns, operates, or leases interests in 39 operating assets, and controls an aggregate net generating capacity of 9,852 MWs. EME Homer City operates one of the largest coal-fired power plant in western Pennsylvania, the 1,884 MW Homer City electric generating station.

5. EME Homer City is subject to numerous environmental regulatory requirements at the state and federal level. Like other power generators, EME Homer City is preparing for new federal regulations expected in the coming months and years. Examples of these issued and upcoming rules and regulations include: the rules regarding the treatment of coal combustion residuals,[1] non-hazardous secondary materials,[2] the Transport Rule, new greenhouse gas reporting requirements and substantive rules,[3] new MACT

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[1] Disposal of Coal Combustion Residuals From Electric Utilities, 75 Fed. Reg. 35,218 (June 21, 2010).

[2] Identification of Non-Hazardous Secondary Materials That Are Solid Waste, 76 Fed. Reg. 15,456 (Mar. 21, 2011).

[3] Mandatory Greenhouse Gas Reporting, 40 C.F.R. pt. 98 (2011); Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31,514 (June 3, 2010).

requirements,[4] and 316(b) regulations for cooling water intake structures,[5] among others.

EME Homer City's Commitment to Emission Reductions

6. EME Homer City supports overall emission reduction efforts; indeed, EME intervened in support of EPA's Clean Air Interstate Rule ("CAIR") when it was challenged in this Court, *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008). Additionally, EME Homer City, and its indirect parent company, EME, have worked with state regulators to pursue aggressive emission reductions at their facilities. In 2006, EME's subsidiary Midwest Generation EME, LLC entered into an agreement with the Illinois Environmental Protection Agency—codified by state rulemaking in 2007—whereby it committed to aggressive fleet-wide reductions in emissions of mercury, NO_X and SO_2 from its Illinois-based coal-fired generation facilities. EME worked with state regulators to determine the installation schedule for the controls needed to achieve the reductions and, in doing so, took into account state priorities.

7. EME Homer City similarly has taken steps to control emissions at its facility. The Homer City facility's three units have had SCRs (selective catalytic

[4] National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units, 76 Fed. Reg. 24,976 (May 3, 2011).

[5] National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities, 76 Fed. Reg. 22,174 (proposed Apr. 20, 2011) (to be codified at 40 C.F.R. pts. 122, 125).

reduction) in place since 2003, which have resulted in reductions of 68,000 tons of NO_X. Similarly an FGD (flue gas desulfurization) on Homer City's Unit 3 has been in place since 2001 and has resulted in emissions reductions of 170,000 tons of SO_2 emissions and 2,500 pounds of mercury.

Effect of Transport Rule

8. All of these efforts that EME Homer City and EME have made to reduce emissions have been based on existing law (the NO_x SIP Call, CAIR, and the Clean Air Mercury Rule) and state priorities. For example, EME Homer City purchased allowances under CAIR with the plan that FGD would be installed on Homer City's remaining units by 2015—the time for compliance under Phase 2 of CAIR. However, the accelerated timing and radically altered emission allocations mandated by the Transport Rule do not permit the lead time needed to respond to this sudden regulatory shift—it is not possible to accelerate installation of these controls, which were scheduled for 2015, to enable them to be installed in time for compliance in 2012. In fact, we are working in good faith and with urgency with the Pennsylvania Department of Environmental Protection to permit the FGD controls for Homer City's remaining two units as expeditiously as possible, but it is physically impossible to have these controls installed by 2012.

9. EME Homer City could not predict the Transport Rule timing until the rule was proposed because it was widely, and, in my opinion, reasonably assumed in

the industry that EPA would do another SIP call to implement the interstate transport requirements. Even then, EME Homer City could not have predicted the harm that would flow from EPA's final rule because the proposed rule provided for broader interstate trading without variability limits (from the assurance provisions) until Phase II of the rule in 2014. *See* 75 Fed. Reg. 45,210, 45,305 (Aug. 2, 2010). Furthermore, the proposed rule's state- and unit-level emission allowance allocations were much more favorable for Homer City. EME Homer City also could not predict the major shift in allocation approach EPA has adopted until it was first proposed in January 2011 in the Notice of Data Availability ("NODA")—and the final rule differs from that. It was too late *at all of these points* for EME Homer City to install major controls before the rule takes effect and these requirements could not have been reasonably anticipated, particularly the so-called variability limits on emission allowances by state that were not foreshadowed before adoption of the final rule and which place significant constraints on emission allowances that are likely to be available in the marketplace in 2012 and 2013..

10. EPA's approach to unit-level allocations in the Transport Rule has given some facilities significantly fewer allocations than they would need to operate and other facilities more allocations than they would need to operate in 2012 and 2013 given current emission controls in place. The reductions required for the facilities that were "shorted" allocations differ significantly from the reductions

facilities were preparing for under CAIR, or what they could have anticipated based on the proposed Transport Rule. For facilities with fewer allocations than needed, achieving these reductions would likely require the installation of major control technology equipment, including flue gas desulfurization equipment ("FGDs" or "scrubbers") and SCR (selective catalytic reduction) or SNCR (selective non-catalytic reduction) equipment. While Homer City's three units already have SCRs installed to reduce NO_x emissions, FGD can cost as much as $300 million (depending on the size of the plant) and requiring significant lead time for construction and installation.

11. However, these installations cannot be completed in time to reduce emissions when the Transport Rule is scheduled to take effect in 2012. Even EPA estimates that it takes 27 months to install a scrubber and 21 months to install an SCR, *see* 75 Fed. Reg. at 45,281, which comes nowhere near to achieving completion by January 1, 2012 starting from the date the rule was finalized and the variability limits on emission allowances were first known. In fact, industry experience is that it can take much longer than those estimates—as long as 40 to 60 months for scrubbers and 32 to 46 months from SCRs, although EME is now working with urgency and good faith with suppliers and PADEP to permit and complete construction of FGDs by 2014—a very aggressive timeframe that may not prove practical in the end.

12. Since there is not sufficient time to install this equipment to reduce emissions by 2012, facilities may either have to curtail operations or pay tens of millions of dollars to their competitors, who were given excess allowances, to purchase the emission allowances needed to operate—if such allowances are even available. Due to the incentives to bank allowances for future years instead of selling, and the opportunities to game the market EPA has designed, units that have been allocated allowances in excess of their emissions are likely to have considerable market power.

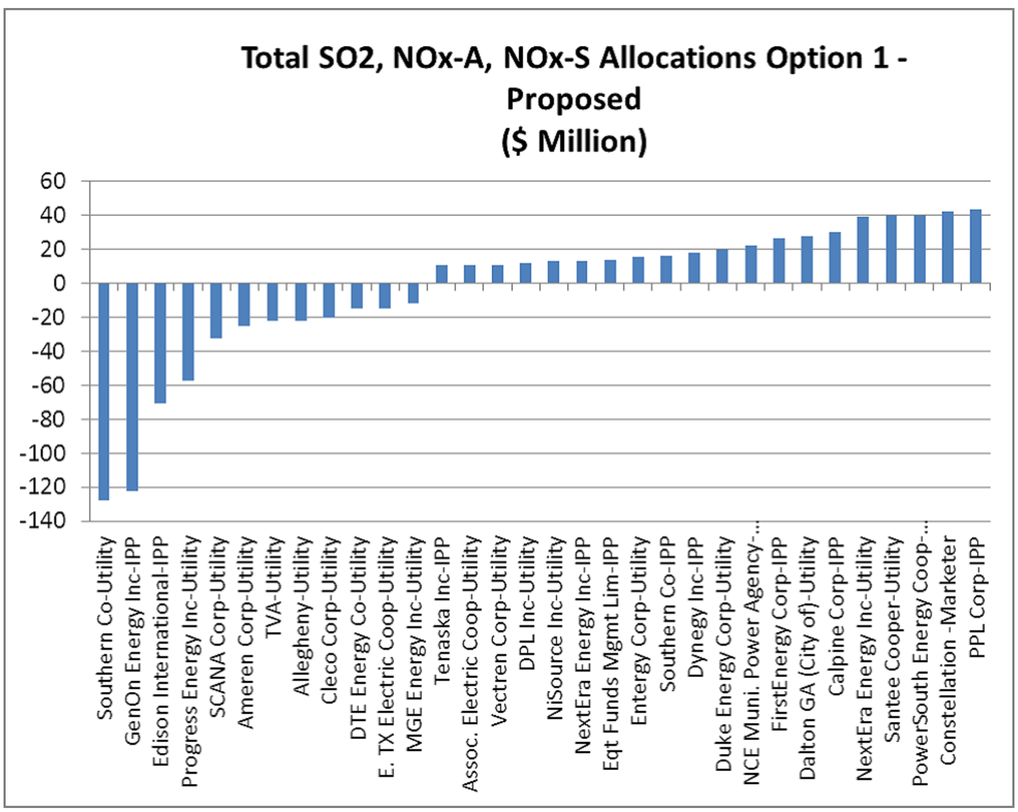
13. Based on historic emissions, the Homer City facility's SO_2 allocation is approximately 85,000 tons short of the allowances it would need to operate in 2012 and 2013, as it only received approximately 22% of the allowances it needs to operate in those years.

14. While EPA suggests that units may comply with the emission reductions by purchasing allowances in the event that it is not possible to install controls in time, 76 Fed. Reg. at 48,280, that will not be the case for EME Homer City because of the way EPA has structured the variability limits/assurance provisions and penalties in its final rule and the fact that the final rule changed the start of these provisions from 2014, as proposed, to 2012. Under the Transport Rule's assurance provisions, the total emissions in a state may only exceed the state's allowance allocation by a fixed margin (called the variability limit). For example, if a state has a total of 100 allowances allocated, and a 10%

variability limit, the total emissions in the state in a given year may add to 110, provided units within the state purchase the appropriate allowances to cover any unit-level exceedance. However, if total emissions in a state go above this maximum variability limit, units within the state are penalized based on the amount of emissions by which they exceeded the sum of their *initial allocation* and their proportionate share of the variability limit, regardless of whether they purchased enough allowances to cover their individual emissions. *Id.* at 48,294. Thus, even if a unit purchased allowances to cover its own emissions, if the state variability limit is exceeded, the unit would be subject to the Transport Rule penalty of a 2 to 1 surrender of the unit's emission allowances for their proportionate share of the amount by which the state exceeded its variability limit. *Id.* If the unit does not hold enough allowances to meet the surrender requirement, it will also be subject to civil penalties. *Id.* at 48,296. These provisions may act to nullify the "trading" option—particularly in Pennsylvania where the state's SO_2 budget for 2012 under the final Transport Rule was 110,000 tons less than in the proposal and is significantly less than the states's historic SO_2 emissions.

15. As part of its evaluation of EPA's proposals for this rule, EME Homer City evaluated the heat-input-based allocation approach EPA first proposed in its NODA for the proposed rule. This heat-input approach to unit-level allocations causes some facilities to receive significantly fewer emission

allowances than needed and others to receive excess allowances. EME Homer City's analysis showed that the heat-input approach proposed in the NODA would result in a $1.5 billion redistribution of wealth from certain companies to others in 2012 and 2013. This analysis was conducted by multiplying the number of tons by which the facilities subject to the Transport Rule were either "short" or "long" on allowances, multiplied by EPA's projected allowance price estimate of $1000/ton for SO_2. This redistribution of wealth is depicted below (this chart was created by EME Homer City based on NODA Option 1, depicts the wealth transfer for one year for all distributions that exceed $10 million, and does not include Texas, which was not part of the proposed rule).



16. The effects of EPA's rule are not confined to simply transferring wealth among competitors, however. Rather, EPA's final rule may fundamentally change how electricity is dispatched in the market. In brief, each competitive electricity market in the country has an "independent system operator" or ISO which is responsible for determining which electricity generating units run on any given day (or, indeed, any given hour) to meet demand (or "load"). For example, the ISO for the Mid-Atlantic region in which EME Homer City is located is PJM Interconnection, LLC ("PJM"). PJM forecasts an electricity load for each hour of every day (incorporating a reserve margin in case electricity demand is higher than anticipated) based on weather, day of the week, time of day and other factors. Additionally, PJM receives offer curves from each generator in the region, offering to dispatch electricity from the generator's assets for a specified price per asset. In simplest terms, PJM sorts those dispatch offers from lowest to highest cost, uses its computer models to identify the least marginal cost at which it can satisfy its load and reserve requirements, and directs each generator which units to run each hour on that basis. The highest cost unit which is dispatched in that hour sets the electricity price which is paid by consumers, and at which all generators are paid.

17. EPA's rule will change how electricity dispatch occurs in either of two core ways. First, if a unit lacks sufficient allowances to operate (and cannot purchase those allowances), it simply will not bid into dispatch—and the ISO

will be required to turn to higher marginal cost units to satisfy its load and reserve requirements. Electricity prices will rise for consumers, while the generator will incur an irrecoverable loss in revenue because its unit cannot generate.

18. Second, if a unit purchases allowances to enable it to run, that allowance price must be factored into the dispatch cost for the unit. EME Homer City estimates, based on EPA's predicted allowance prices, that the cost of allowances will substantially increase electricity prices for units without additional controls. As an illustrative example, if unscrubbed coal today costs an estimated $30/MWh to dispatch, while scrubbed coal costs approximately $32/MWh, once the Transport Rule takes effect, the cost of unscrubbed coal could jump to as high as $45/MWh. As such, the ISO would not dispatch those units so long as it can meet its load and reserve requirements by dispatching other generating units with a lower marginal cost. The net result, again, is that the unit with a Transport Rule shortfall is dispatched less frequently—even if it has purchased sufficient allowances—and electricity prices rise for consumers, while the generator incurs an irrecoverable loss in revenue because its unit cannot generate.

19. Generators who are short of allowances have no meaningful options to avoid these harms. In contrast, if EPA had proceeded under a SIP call to implement the interstate transport requirements, companies would have had meaningful

compliance options. Specifically, sources would have had sufficient time to install the necessary controls that would enable their assets to continue to operate (and dispatch) normally. Moreover, the cost of timely controls would result in only small marginal changes to dispatch pricing, in contrast to the economic displacement that results from the Transport Rule. EME Homer City's economic modeling further shows that—if Homer City were given sufficient time to install controls before rule implementation—the cost of the controls would be recoverable over time, whereas the economic penalty from curtailment of operations or from paying competitors for allowances is irrecoverable.

20. EME Homer City is currently evaluating its options to respond to the significant shortfall in SO_2 allocations for the Homer City units, including interim operational changes in addition to curtailments, but it is clear that EME Homer City will be unable to install FGDs before 2012 (and may be unable to do so by 2014). For the reasons described above, EME Homer City likely cannot meet its requirements solely by purchasing allowances, and may be forced to curtail operations, which may include shutting down one or more of Homer City's three units. Even if it is possible to make up the allocation shortfall through the purchase of allowances, this would require EME Homer City to pay tens of millions of dollars to its competitors—based on EPA's predicted cost of allowances, we estimate as much as $85 million in 2012 alone.

And even if it purchases those allowances in order to have the option of continuing operations, it may no longer be cost effective to run two of Homer City in the constrained market, as discussed above.

21. Either option—purchasing allowances or curtailing operations—would impose irreparable harm on the company. If the Transport Rule takes effect and EME Homer City is forced to pay its competitors tens of millions of dollars to purchase allowances in 2012 and 2013 to continue operating its facility, redress would similarly be unavailable to EME Homer City even if this Court were to later invalidate the rule—it is my understanding that EME Homer City would be unable to recuperate the money paid to its competitors for the allowances. Similarly, any curtailment in operations represents losses in revenue that cannot be recuperated.

22. I also believe the public would share in the harm that would flow from the Transport Rule taking effect. Homer City produces 1,884 megawatts of electricity—enough for two million homes. It employs nearly 260 employees and contractors who earn a higher than average salary of $73,500 per year. Thus, curtailment at this facility could result in job losses, harm to the local economy, and impacts on electricity prices. My understanding, based on a report conducted by the Charles River Associates, is that this could amount to an overall increase in consumer power prices by as much as $514 million per year in 2012 and 2013.

23. If EME Homer City were forced to curtail operations, the potential job losses, increase in electricity costs, and impacts on the local economy could have severe impacts on the company's goodwill in the states and communities it serves.

Need for a Stay of the Transport Rule

24. I believe that a stay of the Transport Rule is necessary to prevent irreparable harm to EME Homer City that would occur from an irretrievable loss of revenue from potential curtailment of operations or an irretrievable commitment of funds to purchase allowances from competitors.

25. It is my understanding that the requirements of CAIR would remain in place during any such stay, so that EME Homer City and other sources would continue to be subject to regulations limiting emissions of the pollutants regulated under the Transport Rule.

I declare under penalty of perjury under the laws of the United States that the foregoing is true and correct.

EXECUTED this 24th day of August, 2011 at Chicago, Illinois.

Douglas R. McFarlan

Douglas R. McFarlan

IN THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA

GENON ENERGY, INC.,	)	Case No. 11-1323
	)	
Petitioner,	)	
	)	
v.	)	
	)	
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY AND LISA P. JACKSON, ADMINISTRATOR,	)	
	)	
Respondents.	)	
	)	

<u>DECLARATION OF ROBERT GAUDETTE</u>

I, Robert Gaudette, do hereby declare under the penalty of perjury, pursuant to 28 U.S.C. §1746, as follows:

1. I am Senior Vice President and Chief Commercial Officer at GenOn Energy, Inc. ("GenOn"). I am also a member of GenOn's Executive Committee, which is responsible for overseeing all aspects of the Company's operations and businesses. I have served in these capacities since GenOn was formed in 2010 as the result of a merger between Mirant Corporation and RRI Energy, Inc. Before the merger, I was Vice President of Mirant's Mid-Atlantic business unit. During my career at Mirant, I served in various other capacities, including Director of

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West Power, Director of NYMEX Trading, and Assistant to the Chief Operating Officer.

2. I am responsible for all of GenOn's commercial activities. My responsibilities include bidding into the wholesale markets for electricity, dispatching generating units, procuring fuel (including coal, natural gas, and oil) for the generating units, and overseeing a variety of trading activities, including the trading of power, fuel, and emission allowances. I am also responsible for GenOn's hedging program, which is described below.

3. I make this declaration in support of GenOn's Motion for a Stay Pending Review, or In the Alternative, Expedited Review. I have personal knowledge of the issues and activities referred to herein, except where stated on information and belief. If called upon to testify, I could and would testify truthfully thereto.

4. This declaration explains the irreparable harm that will result to GenOn from EPA's rule, Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals. 76 Fed. Reg. 48,208 (Aug. 8, 2011) (the "Transport Rule" or "Rule). As discussed below, GenOn already has been harmed by the Rule, even though it is not legally effective until October 7, 2011, because of the uncertainties it has created for our business. Substantial additional irreparable harm will result to GenOn after the compliance

period begins. The economic harm to GenOn will vary from year to year and depend on the value of the allowances granted to GenOn. While we may initially benefit from the program, we project that we will suffer economic harm thereafter.

Background on GenOn

5. GenOn is one of the largest independent power producers in the United States. Because GenOn is not a regulated utility[1], it must compete with other power producers in wholesale electricity markets. GenOn, through its subsidiaries, indirectly owns and operates electricity-generating plants with a total capacity of approximately 24,200 megawatts (mw) – enough electricity to serve about 25 million homes. GenOn's facilities are located in 12 states, including 10 states that are covered by the Transport Rule.

6. The Transport Rule will substantially affect our fleet of coal-fired power plants, which provide reliable baseload power to several major urban areas. GenOn, through its subsidiaries, owns 7,542 mw of coal-fired capacity in states covered by the Rule. Except for one 482 mw plant in Virginia, all these plants (more than 7,000 mw) are located in Pennsylvania, Maryland, and Ohio. Although these plants represent less than 30% of GenOn's total capacity, many are baseload

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[1] Regulated utilities operate as controlled monopolies and are generally free from direct competition. In general, their rates and investment decisions are regulated by a Public Utility Commission (PUC) or Public Service Commission (PSC). The PUC or PSC is charged with the task of ensuring that their rates are reasonable, and regulated utilities are normally guaranteed a specific rate of return on their reasonable and prudent investments.

plants with high utilization factors and are responsible for a substantial portion of GenOn's annual revenue. Thus, EPA's treatment of power plants in these three states under the Transport Rule has a substantial impact on GenOn.

7. GenOn, through its subsidiaries, has approximately 3400 employees. About 2000 of them work at our coal-fired power plants.

Summary -- Impact of the Transport Rule on GenOn

8. The Transport Rule is different than any other rule that applies or has ever applied to U.S. power plants, for several reasons. First, it provides essentially no lead-time. Neither GenOn nor any other power company can install emission controls or make other changes that would appreciably reduce emissions at any plant before the initial compliance deadline. The rule was signed on July 6, 2011, and published in the Federal Register on August 8, 2011. It calls for significant emission reductions beginning on January 1, 2012, fewer than five months after promulgation. To the extent that these reductions can be achieved, it will not be through investments in emission controls but primarily by shifting generation from some plants to others.

9. Second, because the final Rule is substantially different from the proposed rule, there is nothing that GenOn could have done in advance of July 2011 to prepare for the Rule. Some of the changes that EPA included in the final Rule came as a complete surprise to GenOn, despite our continual participation in

the public rulemaking process. All of the changes are harmful to GenOn's coal-fired plants in Pennsylvania and Ohio.

10. Third, in areas that have competitive power markets, the Rule simply requires that business be transferred from some companies, like GenOn, to their competitors. Even though GenOn's coal-fired plants are in compliance with existing EPA and state rules that limit air emissions, we learned this summer that, because several of our plants have complied with existing rules by purchasing allowances, the Transport Rule will leave us at a significant disadvantage compared to some of our competitors.

11. Under the Rule, several of our plants in Pennsylvania and Ohio will be significantly disadvantaged in the wholesale power market except for short periods when electricity demand is high and sustained. It is not clear whether, under these circumstances, it will be economic to keep these plants open.

12. Finally, the Rule undercuts a number of commercial decisions that GenOn has already made. Under power market rules that apply to most of our coal-fired plants, generating companies are required to bid into the "capacity

market" more than 3 years in advance.[2] Thus, GenOn has already entered into contractual obligations to provide capacity through May 31, 2015. Although we have not made final decisions about plant closures, it appears that it may not be economic to continue operating certain plants under the Transport Rule. If we are forced to shut down any plant, we will forgo the revenue we were entitled to receive under these contracts and also be required either to pay financial penalties or purchase capacity to replace the capacity we were going to provide from such plant.

13. The Rule also undercuts much of the "hedging" we have done to protect against future volatility in the price of electricity and the cost of fuels. Like most power companies in competitive markets, GenOn hedges against these risks by contracting to sell a certain amount of electricity in the future at a set time and price, and also contracting for future delivery, at a set time and price, of the fuel necessary to produce this amount of electricity. In this way, GenOn is able to "lock in" a future revenue stream. We have already engaged in hedging activities with contractual obligations well into 2015. The Transport Rule fundamentally changes the economics of our hedging activities with essentially no advance

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[2] Some power plants are only needed during periods of peak demand. In a competitive market, a company may not be able to sell enough electricity during these periods to justify building or maintaining such plants. To ensure that there is sufficient capacity during periods of peak demand, PJM and other system operators have created capacity markets, which allow companies to receive payments in exchange for guaranteeing that a given amount of capacity will be available in future periods.

warning. At the very least, it certainly reduces the value of our hedges. In many cases, depending on future market conditions, it may cost us more to produce electricity than the price at which we have already agreed to sell it.

14. We have also purchased a significant portion of the fuel (coal and gas) that we anticipated we would need through 2014. Although these advance fuel purchases were prudent based on existing and anticipated regulatory requirements at the time, we would have pursued a different strategy if we had received meaningful advance notice about the Transport Rule. Again, had we been able to anticipate anything like the Transport Rule, we would have been able to adjust our strategy for hedging and fuel procurement over the last few years.

15. Finally, in a business like ours that requires substantial capital investments to maintain and upgrade our facilities, we must plan projects and execute contracts several years in advance. We lease rail cars and enter into contracts with railroads and other transport companies to ensure that we will not only own the necessary fuel but also be able to transport it to our plants. We also must contract with vendors and equipment suppliers months or years in advance to ensure that we can conduct even routine maintenance work during planned outages. A rule that fundamentally changes the way in which we can operate with fewer than 5 months' notice will harm our company in many ways.

Background on the Transport Rule

16. EPA promulgated the Transport Rule under the Clean Air Act ("CAA") to reduce emissions of sulfur dioxide ("SO_2") and nitrogen oxides ("NO_X") from fossil fuel power plants in 27 mostly eastern states. The Rule establishes three different "budgets" for power plant emissions in each state: (1) tons of SO_2 that can be emitted during a calendar year; (2) tons of NO_X that can be emitted during a calendar year; and (3) tons of NO_X that can be emitted during each "ozone season," which runs from May 1 to September 30.[3]

17. The Rule also gives three types of emission allowances (corresponding to the three budgets) to the power plants located in each covered state: SO_2 allowances, annual NO_X allowances, and ozone-season NO_X allowances. The total number of allowances given to plants in each state is fewer than the corresponding state budgets because EPA has reserved a certain number of allowances for new plants. This set aside for new plants varies from state to state and ranges from 2% - 8% of the state's budget depending on EPA's projections as to where new generating units will be constructed.

[3] Some states have only one budget – for ozone-season NOX. Others have two – for annual NOX and annual SO2. Most covered states, including Pennsylvania, Ohio, and Maryland, have three budgets. However, there are actually 4 separate programs under the Rule because EPA has created 2 different "zones" for SO2. Each State, however, is placed in either Zone 1 or Zone 2 for purposes of the SO2 program, so no State is covered by all four programs.

18. At the end of every compliance period, each plant must "surrender" enough allowances to cover its emissions during that period, so a plant must have one allowance for every ton of SO_2 or NO_X it emits. Thus, a plant must limit its emissions to the number of allowances it has received from EPA or purchase allowances from its competitors.

19. The Rule, however, also places restrictions on anyone seeking to comply by purchasing allowances. A company faces the risk of substantial financial penalties if its emissions in any state are more than 18 to 21 percent higher (depending on the program) than the number of allowances it has received from EPA for its plants in that state. This 18 to 21 percent number is called the "variability limit," and the penalty works as follows: If total power plant emissions in a state are higher than the corresponding state budget by more than the variability limit, then any company with emissions that exceed its initial allowance allocation by more than the variability limit must pay a substantial penalty by surrendering 2 additional allowances for its share of the state's "exceedance."

20. Because total state emissions are outside any company's control, and because it will be difficult to predict total state emissions in the early years of the program, companies are required as a practical matter to manage their operations to

ensure that emissions from their plants are no more than 18 – 21 percent higher, on a state-by-state basis, than the number of allowances they have received from EPA.

21. When EPA proposed the Transport Rule in August 2010, it specifically acknowledged that it would be impossible for plants to install new emission controls before the initial compliance deadline of January 2012. 75 Fed. Reg. 45,281. EPA stated that the purpose of the “Phase I” emission budgets that apply during the first two years of the rule (2012 and 2013) was simply to ensure that plants operated their existing controls aggressively. *Id.* Thus, under the proposed rule, individual plants were given the number of allowances that EPA projected they would need if they operated their existing emission controls effectively.

22. The final Transport Rule differs substantially from the proposed rule in three ways that have a major impact on GenOn: (1) it imposes substantially lower state budgets for many states – even for 2012, which was fewer than 5 months away when the rule was promulgated; (2) it includes a very different approach for giving allowances to individual plants that substantially reduced GenOn’s share of the state budgets in Pennsylvania and Ohio; and (3) it restricts companies from purchasing allowances to comply with the rule beginning immediately (i.e., in 2012), rather than in 2014, as proposed.

Lower State Budgets

23. In explaining the reasons for lowering the state budgets, the final Rule preamble simply says: "EPA concluded that significant reductions could be achieved by 2012 and that it is important to require all such reductions by 2012 to ensure that they are achieved as expeditiously as practicable." 76 Fed. Reg. at 48,252. This conclusion has a substantial impact on the 2012 SO_2 emissions budgets that EPA established for a number of states, including Pennsylvania, Maryland, and Ohio, as shown below:

Annual SO_2 Allowances for 2012 - 2013

	Proposed Rule	Final Rule	Percentage Change
Pennsylvania	388,612	278,651	-28%
Ohio	464,964	310,230	-33%
Maryland	39,665	30,120	-24%

Annual SO_2 Allowances for 2014 and thereafter

	Proposed Rule	Final Rule	Percentage Change
Pennsylvania	141,693	112,021	-21%
Ohio	178,307	137,007	-23%
Maryland	39,665	28,203	-29%

24. Thus, GenOn and other power plant owners learned for the first time on July 6, 2011, that they would be required to reduce substantially their SO_2 emissions – well beyond those proposed in the proposed rule – in fewer than 6 months. Although we had actively participated in the public rulemaking process,

we had no warning before July 6 that the rule would require substantial additional reductions in just a few months.

25. EPA justifies these changes in the final rule by stating that, in addition to operating existing controls aggressively, substantial additional reductions can be achieved in fewer than 6 months by "installing combustion controls, fuel switching, and increased dispatch of lower-emitting generation which can be achieved by 2012." 76 Fed. Reg. at 48,252. The preamble to the Rule does not provide any meaningful explanation of these assertions, but simply says that EPA has "updated" its model to incorporate new information about these newly discovered options for immediate emission reductions. *Id.* at 48,213, 48,248 – 48,252. The preamble also says: "In general, compliance mechanisms that do not involve post-combustion control installation are feasible before 2014. For this reason, EPA believes it is appropriate to require these emissions to be removed in 2012." *Id.* at 48,252.

Allocations to Individual Plants

26. The second significant difference between the proposed and final rules involves the way in which allowances are given to individual units. Rather than giving allowances, as originally proposed, to units based on their projected operations with the effective application of existing emission controls, the Agency decided to exercise its "broad discretion" to distribute allowances based primarily

on historic heat input. *Id.* at 48,287-48,288. This is essentially a measure of how much power a plant has historically produced. This means that some plants (primarily those with post-combustion controls) are given far more allowances than they need based on historic operations, while other plants receive substantially fewer allowances than they need to cover their historic operations.

27. Post-combustion controls are generally "scrubbers" to reduce SO_2 emissions and selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) systems to reduce NO_X emissions. Although post-combustion controls are very costly to install, plants that now have such controls have not borne the full cost of installing them. Current cap-and-trade programs, including the Acid Rain Program and the NO_X SIP Call, were specifically designed to ensure that plants without such controls are required to purchase allowances from those that have them and thus subsidize the cost of their installation. In this way, all power plants have shared in the cost of controls that are installed only on some of the plants – generally those that can be controlled most cost-effectively. The allowance scheme that EPA included in the final Rule undercuts this basic feature of the existing programs. It provides a substantial, unjustified windfall to plants with post-combustion controls and penalizes plants without them, even though all plants collectively paid for the controls through the existing cap-and-trade programs.

28. GenOn has installed post-combustion controls on the majority but not all of its plants. However, much of our capacity with such controls is located in a single state – Maryland. Because there are no large uncontrolled coal-fired plants in Maryland, EPA gave relatively few allowances to Maryland, and we received very few "excess" allowances for our Maryland plants even though we have recently installed very costly controls on them. If one or more of these plants were located in Pennsylvania or Ohio, we would have received a significant number of excess allowances.

29. The approach that EPA adopted in the final Rule for distributing allowances will have a substantial impact on GenOn, as shown on the following chart. It shows, on a plant-by-plant basis, the emission allowances that GenOn would have received under the proposed rule compared to the allowances it actually received in the final Rule.

	Annual SO_2		Annual NOx		Ozone NOx	
STATE / PLANT	Proposed Allocation	Final Allocation	Proposed Allocation	Final Allocation	Proposed Allocation	Final Allocation
OHIO						
Avon Lake	34,377	7,351	7,085	2,137	2,812	906
Niles	7,838	2,393	4,572	695	1,835	293
OHIO TOTAL	**42,215**	**9,744**	**11,657**	**2,832**	**4,647**	**1,199**
	Difference:	**-32,471**	Difference:	**-8,825**	Difference:	**-3,448**
PENNSYLVANIA						
Brunet Island	-	-	-	26	-	25
Cheswick	4,391	7,086	1,142	2,624	462	1,149
Conemaugh (x16.45%)	1,107	1,336	3,169	1,958	1,391	999
Elrama	7,044	4,916	6,150	1,957	2,385	907
Hunterstown	-	6	50	245	32	235
Keystone (x16.67%)	1,114	5,556	417	2,057	183	448
Mountain	-	21	43	13	43	15
New Castle	24,525	3,504	3,283	1,297	1,285	622
Portland	29,462	5,924	3,324	2,200	1,453	1,115
Seward	3,961	8,457	1,588	2,415	690	1,001
Shawville	59,063	8,953	7,490	3,315	3,253	1,722
Titus	18,906	3,294	2,376	1,220	1,031	661
Tolna	-	11	-	5	-	6
Warren	-	-	-	-	-	-
PENNSYLVANIA TOTAL	**149,573**	**49,064**	**29,032**	**19,332**	**12,208**	**8,905**
	Difference:	**-100,509**	Difference:	**-9,700**	Difference:	**-3,303**
MARYLAND						
Chalk Point	1,673	5,259	1,518	2,880	656	1,430
Dickerson	2,288	2,977	3,760	1,626	1,535	728
Morgantown	4,486	6,990	2,507	3,838	1,098	1,546
MARYLAND TOTAL	**8,447**	**15,226**	**7,785**	**8,344**	**3,289**	**3,704**
	Difference:	**6,779**	Difference:	**559**	Difference:	**415**

30. The first set of charts (in paragraph 23) simply shows how much the state SO_2 budgets were reduced from the proposed rule to the final Rule fewer than 5 months before the initial compliance period. The second set (in paragraph 29, immediately above) shows the combined impact on GenOn of (1) the lower state budgets and (2) EPA's new approach for allocating the state budget to individual plants. Although GenOn's allocation went up in Maryland by a total of 7,753 tons

(considering all three programs), it went down by a much greater amount in Pennsylvania and Ohio – a total of 158,257 tons.

The Transport Rule's Impact on GenOn

31. Above I describe the substantial changes between the proposed and final rule and how these changes will affect GenOn. This description, however, does not explain the full impact of the Rule on GenOn. The best way to show the Rule's immediate impact is to compare current emissions from GenOn's facilities to the number of emission allowances it will receive for 2012. Although GenOn will be allowed to purchase some additional allowances for compliance purposes, a comparison of current emissions to GenOn's initial allocation provides a good measure of the burden that the Rule will impose on GenOn in fewer than 5 months after it was promulgated.

32. The following chart shows the most recent emissions data from GenOn's facilities in Pennsylvania, Ohio, and Maryland compared to the 2012 allowances they received under the final Rule. For most plants, the chart shows current emissions as the average annual emissions over the most recent 5-year period (2006-2010). This is the generally accepted way of showing "current" emissions because it evens out years of unusually high or low power demand. This approach, however, would overstate current emissions at 5 large plants where GenOn recently installed SO_2 scrubbers (Dickerson, Morgantown, Chalk Point,

Cheswick, and Keystone) at a cost of more than $1.7 billion. 2010 was the first full year that these plants operated with scrubbers, so the chart only shows 2010 SO_2 emissions data for these plants. (Showing the annual average over the last 5 years at these plants would be a stronger way to make my point but would overstate the impact of the Rule on GenOn because we have already installed SO_2 controls at these plants).

	Annual SO_2		Annual NOx		Ozone NOx	
STATE / PLANT	Historical Tons (06-10)	Final Allocation	Historical Tons (06-10)	Final Allocation	Historical Tons (06-10)	Final Allocation
OHIO						
Avon Lake	35,500	7,351	5,584	2,137	2,219	906
Niles	11,573	2,393	3,097	695	1,085	293
OHIO TOTAL	**47,073**	**9,744**	**8,681**	**2,832**	**3,304**	**1,199**

PENNSYLVANIA						
Brunot Island	-	-	10	26	10	25
Cheswick	11,806	7,086	3,661	2,624	858	1,149
Conemaugh (x16.45%)	1,164	1,336	3,273	1,958	1,308	999
Elrama	2,810	4,916	3,729	1,957	1,632	907
Hunterstown	3	6	56	245	35	235
Keystone (x16.67%)	6,520	5,556	1,671	2,057	278	448
Mountain	14	21	34	13	28	15
New Castle	12,477	3,504	2,197	1,297	852	622
Portland	29,391	5,924	3,333	2,200	1,217	1,115
Seward	7,888	8,457	2,000	2,415	796	1,001
Shawville	44,261	8,953	6,461	3,315	2,588	1,722
Titus	11,631	3,294	1,887	1,220	756	661
Tolna	7	11	13	5	13	6
Warren	-	-	-	-	-	-
PENNSYLVANIA TOTAL	**127,972**	**49,064**	**28,325**	**19,332**	**10,371**	**8,905**

MARYLAND						
Chalk Point	3,150	5,259	4,366	2,880	2,213	1,430
Dickerson	2,597	2,977	4,321	1,626	1,743	728
Morgantown	5,276	6,990	1,999	3,838	741	1,546
MARYLAND TOTAL	**11,023**	**15,226**	**10,686**	**8,344**	**4,697**	**3,704**

33. As shown above, based on recent operations at our Ohio plants, EPA has given us only 20% of the SO_2 allowances we would need to cover our historic emissions. We fare somewhat better in Pennsylvania, but still only receive 38% of the SO_2 allowances needed to cover historic operations. In Maryland, where we recently installed state-of-the-art SO_2 controls at all our coal-fired plants and SCRs at several of them as well (at a cost of approximately $1.67 billion), we do receive "excess allowances," but the number is trivial compared to the shortfall at our other plants. Looking at SO_2 emissions from, and SO_2 allowances given to, all GenOn's plants, we receive fewer than 40% of the allowances we would need to produce and sell the amount of power we have been generating from our coal-fired plants for many years.

34. It might be fair to say that, in order to achieve the emission reduction goals that EPA has set for 2012, we should reduce our SO_2 emissions by 60%. The implied emission reduction requirements for NO_X (both annual and ozone-season) are similar in magnitude. It would be possible for GenOn to achieve this level of reduction by installing advanced emission controls on our plants not already equipped with them. This means the installation of scrubbers for SO_2 reductions and either an SCR or an SNCR system for NO_X reductions.

35. Even EPA recognizes, however, that these installations cannot be completed in time to reduce emissions by the time the Transport Rule is scheduled

to take effect, fewer than 5 months after it was promulgated. EPA estimates that it takes 27 months to install a scrubber and 21 months to install an SCR, see 75 Fed. Reg. at 45,281. According to industry experts, it actually takes much longer. Based on my experience and presentations from a variety of experts, I believe a more realistic estimate is 40 to 60 months for a scrubber and 32 to 46 months for an SCR. This does not take into account new EPA and state permitting requirements for major capital projects of this kind, which are likely to cause additional delays. I also believe that there is likely to be a shortage of materials and labor due to increased demand for control equipment installation at power plants in response to the Transport Rule and other upcoming EPA regulations. If so, EPA's estimates are even more unrealistic.

36. In any event, no one asserts that it is possible to install major new emission controls in fewer than 5 months. As a result, many of our coal-fired units will operate less (and perhaps much less) than they have operated historically, and we likely will still need to purchase allowances from our competitors.

37. As noted above, the allowance purchase option is limited by the "variability limits" that EPA included in the final rule. (Under the proposed rule these trading limits did not apply until 2014). Even if the variability limits did not exist, and GenOn could comply by purchasing allowances, the Rule would simply result in massive wealth transfers from companies like GenOn to their competitors.

Based on EPA's projections for allowance prices, GenOn would need to pay its competitors millions of dollars a year to continue operating the power plants as we have been operating over the last few years.

38. However, the primary harm to GenOn results not from the need to purchase allowances but from the fundamental changes that the Rule will require in the dispatch of generating units.

39. In each region of the country where we operate coal-fired plants, there is an "independent system operator" or ISO that is responsible for determining which electricity-generating units run on any given day (or, indeed, any given hour). For example, the ISO for the Mid-Atlantic region is PJM. PJM forecasts an electricity load for each hour of every day based on weather, day of the week, time of day and other factors. PJM receives "offer curves" from each generator in the region, offering to dispatch electricity from the generator's assets for a set price per asset. In essence, PJM sorts those dispatch offers from lowest to highest cost, uses its computer models to identify the cheapest marginal cost at which it can satisfy its load and operating reserve requirements, and tells each generator which units to run each hour on that basis. The highest cost unit that is dispatched in that hour sets the electricity price at which all generators are paid (whether or not their assets could dispatch for a lower cost).

40. The Rule will fundamentally change how electricity dispatch occurs because generating companies must include the cost of allowances when bidding into the market, regardless of whether they receive them from EPA or purchase them from their competitors. Electricity prices will rise for consumers already struggling in many cases from the slow economic recovery, while generators like GenOn will incur an irrecoverable loss in revenue because they will be at a significant cost disadvantage compared to their competitors. This cost disadvantage goes well beyond what is necessary to reduce emissions because the Rule does not provide companies time to install emission controls.

41. Given the almost-immediate deadline for compliance, I believe that EPA's projected allowance prices are too low. Even using EPA's projections (\$1000 per ton for SO_2, \$500 per ton for annual NO_X, and \$1300 per ton for ozone-season NO_X), we calculate that the Rule will cause a substantial (and, I believe, unjustifiable) increase in the cost of generating electricity from a number of coal-fired plants that fully comply with existing regulatory requirements.

42. Today, uncontrolled coal units (units without post-combustion controls for either SO_2 or NO_X) cost approximately \$35 per megawatt hour (MWh) to dispatch. Fully controlled coal units (i.e., units that have post-combustion controls for both SO_2 and NO_X) cost approximately \$40/MWh to dispatch – a difference of approximately \$5/MWh. Because the Transport Rule takes effect

before any additional post-combustion controls can be installed, we project that the cost of uncontrolled units will increase by at least $18/ MWh. This is a relatively easy calculation using EPA's projections for allowance prices (noted above) and other standard assumptions (a heat rate of 10 MMBtu/MWh and an SO_2 rate of 3 lbs/MMBtu). Thus, because the compliance deadline does not allow time for the installation of new controls, the cost of dispatching a unit without post-combustion controls will increase to at least $53/MWh. As such, the ISO will not dispatch that uncontrolled unit so long as it can meet its load and operating reserve requirements by dispatching other generating units with a marginal cost of less than $53/MWh. Again, the results are (1) uncontrolled units are dispatched less frequently – even if they have purchased sufficient allowances – and (2) electricity prices increase for consumers. The generator incurs an irrecoverable loss in revenue because its unit is dispatched less often. In essence, because the Rule does not allow any time for the installation of emission controls, it simply transfers business and revenue from companies like GenOn to our competitors.

43. Generators that fully comply with all existing rules and regulations but have not yet installed advanced pollution controls have no meaningful options to avoid these harms because of the time it takes to permit and install such controls. With the lead-time that EPA (and Congress) has provided in prior rules, the cost of installing controls would result in only small marginal changes to

dispatch pricing (as reflected in the example above), in contrast to the large impact that results from the immediate imposition of the Transport Rule. GenOn believes that, if it had been given sufficient time to install controls before rule implementation, the cost of the controls at some plants likely would have been recoverable over time, whereas the economic penalty from curtailment of operations or from paying competitors for allowances is irrecoverable.

44. The Transport Rule will also impose other harms on GenOn. As noted above, we are legally required, for most of our coal-fired plants, to commit capacity into the wholesale power market three years in advance. Thus, GenOn has a legal obligation to deliver capacity through May 31, 2015. In order to meet these obligations and also comply with the Transport Rule (including requirements that no one could have predicted), GenOn may incur substantial and unrecoverable costs.

45. Although GenOn has not yet been able to analyze the implications of the “updated” (and radically different) modeling that apparently supports the Rule, EPA appears to assume that the substantial reductions that are required in less than 5 months will largely be achieved “by increased dispatch of lower-emitting generation which can be achieved by 2012.” 76 Fed. Reg. at 48,252. This apparently means that gas-fired power plants will be expected to provide more baseload power. Yet EPA also assumes that baseload coal-fired plants will be

available to be operated as peaking units. If this is indeed the result of EPA's near-term compliance deadline, I believe that maintenance costs will go up and availability will go down on a number GenOn's units. GenOn's coal units were designed as baseload units that run essentially all the time. If they are subject to more starts and stops, maintenance costs will increase and performance will suffer as well.

Need for a Stay of the Transport Rule

46. GenOn is still evaluating its options for complying with the Transport Rule – a rule that is radically different from the proposed rule and from any other environmental rule that I have ever seen. It is clear that GenOn's generating facilities cannot operate as they have been operating in recent years and limit their emissions to the number of allowances they receive under the Rule. Nor can they install the type of emission controls that would be necessary to achieve this result for at least 2 or 3 years. As the Rule now stands, operations at our coal-fired plants will be reduced and we will also likely need to purchase allowances and thus transfer millions of dollars a year to our competitors. Even so, GenOn cannot purchase more than 18 -21 percent of the allowances it has received under the Rule without exceeding the "variability limits" in the Rule and facing the risk of substantial penalties. The loss of the revenue from our coal-fired plants may essentially force us to close some plants prematurely.

47. GenOn and its shareholders will suffer substantial and irreparable harm if the Rule is not stayed and we must begin to comply in less than 4 months. We will lose revenue that cannot be recuperated, even if this Court later determines that the Rule is unlawful.

48. I believe that a stay of the Transport Rule is necessary to prevent irreparable harm to GenOn that would occur from an irretrievable loss of revenue and/or an irretrievable commitment of funds to purchase allowances from competitors.

I declare under penalty of perjury under the laws of the United States that the foregoing is true and correct.

EXECUTED this 13th day of September, 2011, in Houston, Texas.

Robert Gaudette

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Luminant Generation Company LLC, et al.	)	
Petitioners,	)	
v.	)	Case No. 11-1315
Environmental Protection Agency, et al.	)	
Respondents.	)	

Declaration of David A. Campbell

1. I am the Chief Executive Officer of Luminant Holding Company LLC, a subsidiary of Energy Future Holdings Corp (EFH) that holds several companies engaged in the competitive electric power business in Texas.[1] As CEO, I oversee the full scope of Luminant's activities, which include electric power generation, lignite mining, and wholesale marketing and trading of electricity. I provide this declaration in support of Luminant's motion to stay the Texas provisions of the Cross-State Air Pollution Rule (CSAPR), a rule that will have highly damaging and irreparable impacts on Luminant's operations, as described below. This declaration is based on my personal knowledge of facts and analysis conducted by me and my staff.

2. I was named CEO of Luminant in 2008. Previously, I served as EFH's chief financial officer. In that role, my team and I were responsible for the company's financial strategy, corporate planning, enterprise risk management, treasury, tax, accounting and investor

[1] Luminant Generation Company LLC, Luminant Energy Company LLC, Sandow Power Company LLC, Big Brown Power Company LLC, Oak Grove Management Company LLC, Luminant Mining Company LLC, Big Brown Lignite Company LLC, and Luminant Big Brown Mining Company LLC are each wholly-owned subsidiaries of Luminant Holding Company LLC. Each of these entities is harmed by the Cross-State Air Pollution Rule and each is a petitioner in this case. "Luminant" is used throughout my declaration to refer to all of these entities collectively.

relations functions. I joined EFH in 2004 as executive vice president of corporate planning, strategy and risk.

3. Before joining EFH, I was a principal in the Dallas office of McKinsey & Company, Inc., where I led the Texas and Southern Region hubs of McKinsey's corporate finance and strategy practice.

4. I graduated with a bachelor's degree from Yale University and received a J.D. from Harvard Law School. I also received a master's degree from Oxford University.

SUMMARY OF CSAPR'S IMPACT ON LUMINANT

5. As the state's leading producer of electricity, Luminant operates more than 15,400 megawatts (MW) of generation in Texas, including nuclear-powered, gas-fueled, and coal-fueled power plants. In all, Luminant contributes more than a quarter of the electricity dispatched to Texas consumers and businesses by the Electric Reliability Council of Texas (ERCOT), the independent system operator that manages the state's competitive power market and the electric power grid that serves the majority of the state. With a current portfolio of more than 900 MW of wind energy and a commitment to increase it to 1,500 MW, Luminant is the largest wind purchaser in Texas and the fifth largest in the United States. Coal, however, remains a critical source of energy to Luminant and Texas, providing approximately 50 percent of Luminant's generating capacity, and 40 percent of electricity generation in Texas.

6. A year ago, the U.S. Environmental Protection Agency (EPA or the Agency) published a proposed version of CSAPR (then known as the Clean Air Transport Rule (CATR)) that required electric generating units (EGUs) in Texas to reduce nitrogen oxide (NO_x) emissions during ozone season (May-September) but did not include Texas in the group

of states required to reduce annual nitrogen oxide (NO_x)and sulfur dioxide (SO_2) emissions from EGUs in order to address effects related to fine particulate matter ($PM_{2.5}$) in downwind states. EPA stated that it did not include Texas in CATR's annual programs because the Agency concluded that Texas emissions have no significant downwind effect on other states related to $PM_{2.5}$. Without providing Luminant and other stakeholders an opportunity for notice and comment on Texas's inclusion in the annual programs and the specific annual limits that would apply to Texas and Texas sources, EPA reversed its position in the final rule, issuing CSAPR on August 8, 2011 with provisions that require Texas to take drastic steps to dramatically reduce annual NO_x and SO_2 emissions in less than five months from final publication of the rule. In addition, for the ozone program, CSAPR imposes seasonal NO_x limits for Texas that are substantially lower than the limits proposed in CATR, also on an abbreviated timeline.

7. CSAPR requires that Texas halve its annual SO_2 emissions and substantially reduce both annual and seasonal NO_x emissions – all in less than five months. Because Luminant is Texas's largest provider of electricity, these surprise restrictions will not only irreparably harm the company, they have impacts that will ripple throughout Texas. As described below, following an extensive process during which Luminant carefully reviewed all possible options for complying with CSAPR beginning on January 1, 2012, Luminant has determined that it must immediately make significant and detrimental changes in its operations in order to do so. As discussed in more detail below, the emissions limits and timetable in CSAPR for Texas sources will result in a host of harms, including:

a) **Idling of facilities:** Luminant will be forced to cease operations at three Texas lignite mines in East Texas and idle two major EGUs at the Monticello Power Plant by January 1, 2012. One of the mining areas that will be affected was only recently opened at a cost to Luminant of $80 million.

b) **<u>Loss of jobs:</u>** Implementing the changes described above will require the elimination of approximately 400 and possibly up to 450 full-time jobs by early 2012 and the eventual elimination of more than 500 jobs. Many Luminant employees have been working in these jobs—typically among the highest-paying and most sought-after, stable jobs in their communities—for decades. During these difficult economic times, job opportunities for these workers will be extremely limited and perhaps nonexistent, particularly in the rural communities where these workers live.

c) **<u>Harm to communities:</u>** In addition to the loss of jobs, the communities where the affected Luminant facilities are located will lose significant revenue and resources. Luminant is the economic lifeblood of many communities. In the communities where Luminant will be forced to curtail operations, Luminant paid more than $25 million in 2010 taxes, payments that will be dramatically reduced as a result of CSAPR. In addition, Luminant employees contribute significantly to the charitable, social and cultural life of those communities. In 2010, Luminant plants and mines donated more than $70,000 to charitable community activities and Luminant employees logged approximately 3,800 hours of volunteer time. Luminant also hires local and regional vendors to provide a range of services and will have to curtail those expenditures, likely resulting in further workforce reductions.

d) **<u>Loss of electricity generation:</u>** Luminant – and the whole Texas grid – will lose approximately 1200 MW of generating capacity due to the idling of Luminant's two Monticello units as of January 1, 2012, just before the demand for electricity during the winter season has historically seen its highest levels. In addition, Luminant – and the grid – will lose an additional approximately 100 MW of generating capacity during peak hours, as the company will have to derate (decrease generation at) other units to comply with CSAPR's Texas emissions budgets. Overall, Luminant's coal generation fleet will produce and sell less electricity in 2012 and beyond—approximately 10 terawatt hours (TWh) less annually than it would have absent CSAPR

e) **<u>Threat to grid reliability:</u>** The generation lost due to idling the two Monticello units and derating other units will threaten the reliability of the electric grid in Texas. At a time when Texas has consistently been breaking peak electricity demand records, Luminant will not be able to generate 1300 MW of the energy that ERCOT has relied on to ensure grid stability. As ERCOT's Warren Lasher explains in his declaration, which I have reviewed, ERCOT believes that the risk of rolling blackouts will increase as a result of the lost generation from Luminant alone.

f) **<u>Financial harm to Luminant:</u>** Luminant will suffer extensive monetary injury that cannot be recovered from EPA or others. Luminant projects that CSAPR will cost the company $260 million in lost Earnings Before Interest, Taxes, Depreciation and Amortization expense (EBITDA) in 2012 alone as a result of reduced generating capacity and switching to higher-cost fuels.

Since Luminant operates in a deregulated competitive energy market, there is no way that Luminant can recover the revenue it will start to lose on January 1, 2012, even if CSAPR is eventually modified or overturned. These numbers are net of any price increase Luminant might receive for generation at its surviving units. Typically, energy companies like Luminant are valued based on EBITDA multiples in the 7-9 range. Using this methodology for just the single-year 2012 EBITDA impacts from CSAPR, CSAPR would reduce Luminant's enterprise value by $1.8 to $2.3 billion. In addition, in 2011 and 2012, Luminant will incur increased capital expenses of approximately $280 million, and it expects to incur approximately $35 million related to the severance of the employees who will lose their jobs.

g) **Increase in electricity prices:** According to simple economics of supply and demand, Luminant's reduced supply of generation starting in 2012 likely will increase wholesale electricity prices in Texas. Luminant currently estimates that wholesale prices will increase by at least $3.00 per megawatt hour (MWh) on an average annualized basis.

8. CSAPR is forcing the company to take the measures described herein by January 1, 2012. If EPA had given Luminant and Texas an opportunity to comment on significant errors in the rule that affected the Texas budget and had afforded a more reasonable timeframe for compliance, these imminent harms possibly could have been avoided. However, if CSAPR is not revised or stayed, Luminant cannot avoid the substantial, irreparable harms described above. Moreover, the company will face significant harms even before January 1, 2012, because in order to perform some of the equipment upgrades required to comply with CSAPR, the company must start ordering major equipment and commissioning engineering and construction work immediately, increasing Luminant's planned capital expenditures for 2011 by $110 million. Luminant will also reluctantly give notice of layoffs to employees in late 2011, which is likely to lead to the immediate loss of employees.

LUMINANT'S GENERATION AND MINING OPERATIONS

9. Luminant owns and operates twelve coal-fueled EGUs at five generating plants in Texas (Big Brown, Martin Lake, Monticello, Sandow, and Oak Grove) that produce

approximately 8,000 MW of power used by approximately three million Texans across the state. Luminant's coal-fueled EGUs are all "mine mouth" plants that were intentionally constructed very close to the lignite mines that exist solely to provide lignite coal to fuel the generating units.

10. Luminant operates nine lignite mines that provide fuel to its twelve coal-fueled generating units. Over the last 40 years, Luminant has mined and restored over 67,800 acres and planted more than 30 million trees in a mine reclamation program that consistently earns the nation's top awards for environmental excellence, including an unprecedented five Director's Awards from the Department of the Interior's Office of Surface Mining.

11. Luminant currently employs approximately 1,000 people across the five coal-fueled plants and approximately 1,900 people in its nine mines.

12. Luminant has already implemented a host of measures to reduce SO_2 and NO_x emissions from its coal-fueled plants. In 2007, Luminant committed to a very significant voluntary program to reduce the emissions from its legacy coal-fueled power plants. The environmental control equipment that Luminant has already installed is summarized in Table 1.

Table 1 - Currently Installed Environmental Control Equipment At Luminant Coal Units

Currently Installed Environmental Control Equipment At Luminant Coal Units

✘ Currently installed

		A	B	C	D	E	F	G
	Coal Unit	FGD (Scrubber)[1]	Activated Carbon Injection[2]	ESP[3]	SNCR[4]	SCR[4]	Bag-house[3]	Fuel Source
1	Oak Grove 1	✘	✘			✘	✘	Lignite
2	Oak Grove 2	✘	✘			✘	✘	Lignite
3	Sandow 4	✘	✘	✘		✘		Lignite
4	Sandow 5	✘	✘		✘		✘	Lignite
5	Martin Lake 1	✘	✘	✘				Lignite/PRB[5]
6	Martin Lake 2	✘	✘	✘				Lignite/PRB
7	Martin Lake 3	✘	✘	✘				Lignite/PRB
8	Monticello 1		✘	✘	✘		✘	Lignite/PRB
9	Monticello 2		✘	✘	✘		✘	Lignite/PRB
10	Monticello 3	✘	✘	✘	✘			Lignite/PRB
11	Big Brown 1		✘	✘	✘		✘	Lignite/PRB
12	Big Brown 2		✘	✘	✘		✘	Lignite/PRB

[1] FGD refers to flue gas desulfurization systems that reduce SO2 emissions with co-benefits of other emissions reductions.
[2] Activated carbon injection systems reduce mercury emissions.
[3] ESP refers to electro-static precipitation systems. ESP and bag-house systems reduce particulate emissions with co-benefits of other emissions reductions.
[4] SNCR refers to selective non-catalytic reduction systems. SCR refers to selective catalytic reduction systems. Both systems reduce NOx emissions.
[5] PRB refers to Powder River Basin coal transported to plants via railcar.

13. Luminant's investments and those of other sources in Texas have paid off. According to EPA's Clean Air Markets Division, emissions of both SO_2 and NO_x have steadily decreased in the Texas power sector over the period of 1995 to 2010. Specifically, SO_2 emissions decreased 26% from approximately 621,000 to 462,000 tons, while NO_x

emissions decreased 62% from 376,000 to 146,000 tons. Approximately 73,000 tons of the 159,000 tons of SO_2 reductions have come since 2005, with 57,000 tons (35%) attributable to Luminant alone. Further, the Texas power sector's emissions rates are below the U.S. average. Its 2010 SO_2 emission rate (0.30 lbs/MMBtu) was 24% lower than the national average of 0.40 lbs/MMBtu. Similarly, Texas's NO_x emission rate (0.095 lbs/MMBtu) was 42% below the national average of (0.164 lbs/MMBtu).

CSAPR'S REQUIREMENTS

14. When it proposed CSAPR, EPA did not propose annual SO_2 and NO_x emissions limitations for Texas. But when the Agency issued the final rule, it mandated – without providing fair notice and opportunity to comment – that Texas reduce its SO_2 emissions to 243,954 tons, a 47 percent reduction. CSAPR further requires that Texas reduce its NO_x emissions to 133,595 tons, an 8 percent reduction. The annual reductions that EPA is requiring of Luminant in particular—64 percent for SO_2 and 22 percent for NO_x—are even more severe. Finally, CSAPR also requires that Texas reduce its NOx emissions during ozone season by 12,531 tons, a reduction that is 20 percent greater than the reduction EPA proposed in CATR. These unprecedented reductions must all be implemented in time to begin compliance on January 1, 2012, which is less than five months from the day that EPA published the rule in the Federal Register.

LUMINANT'S COMPLIANCE OPTIONS

15. Since EPA's announcement of its decision to impose annual emissions budgets for SO_2 and NO_x and a significantly more stringent seasonal NO_x budget on Texas, Luminant has dedicated significant effort to understanding the rule and analyzing compliance options. For the better part of the last two months, my top priority and that of all of my senior

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staff, as well as a large number of other Luminant employees, has been determining how Luminant can comply with CSAPR with the least amount of harm to the company, its employees and communities, and the reliability of the Texas grid.

16. Since the announcement of the Final Rule, I have directed more than 75 employees working essentially full time and approximately 300 people total in exploring all options for compliance, including switching fuel sources, reducing power generation, purchasing emissions allowances, installing new equipment, upgrading existing equipment, implementing new emission reduction technology such as dry sorbent injection, and many other options.

17. We have run dozens of scenarios through multiple analytical models to determine how the company can comply with CSAPR with the least adverse impact. There was not a single scenario that did not involve substantial and irreparable harm to the company starting well before the January 1, 2012 compliance date. We have continuously researched and refined the model inputs to verify that each model's assumptions are correct and that there are no additional options.

18. Based on these many hours of analysis and countless discussions about dozens of scenarios, I, along with my executive management team and that of our parent company Energy Future Holdings Corp., determined that in order to comply with CSAPR, Luminant must take the following steps:

    a) As of January 1, 2012, Luminant will idle two EGUs at the Monticello Power Plant in Titus County, Texas. This will reduce Luminant's generating capacity and available generation in ERCOT by approximately 1200 MW.

    b) As of January 1, 2012, Luminant will switch to using 100% Powder River Basin (PRB) coal at the Big Brown Power Plant (2 units) in Freestone County, Texas and Monticello Unit 3. PRB coal, which is sourced from Wyoming, is naturally lower in sulfur than lignite and therefore produces less SO_2 in the EGU emissions. However, because Luminant's coal units were not designed to burn 100% PRB, the units will suffer reduced generation levels and be forced to take additional maintenance outages to address the effects of PRB on boilers that were originally designed to burn lignite.

c) As a result of the switch to PRB coal at the Big Brown Power Plant and Monticello Unit 3 and the idling of two EGUs at the Monticello Power Plant, the three lignite mines associated with those two plants will be closed as well. These closures are described in more detail in Stephen Kopenitz's declaration, which I have reviewed.

d) Luminant will have to derate (decrease generation at) a number of its remaining electric generating units in order to comply with CSAPR's Texas emissions limitations, which require fuel switching to 100% PRB. This will result in an additional loss of approximately 100 MW of generating capacity.

e) Luminant will implement scrubber upgrades at the Martin Lake Power Plant, Monticello Power Plant Unit 3, and Sandow Power Plant Unit 4 at a cost of approximately $250 million and selective non-catalytic reduction technology (SNCR) at the Martin Lake Power Plant at a cost of approximately $30 million.

19. There are certain measures that Luminant has considered, but will not be able to take to comply with CSAPR in the short term. As discussed in more depth in the declaration of Ken Smith, which I have reviewed, it will be infeasible to install major emissions control components such as new scrubbers, new SCRs, or baghouses by January 1, 2012 (or even May 1, 2012, when seasonal NOx restrictions kick in). Installing such technology typically takes three years or more, assuming that there are no permitting delays.

20. Further, as discussed at more length in the declaration of Matthew Goering, which I have reviewed, Luminant will not be able to achieve compliance by purchasing emissions allowances (emissions credits) under any of the three trading programs established by CSAPR. Based on the extensive analysis conducted by Mr. Goering and his staff, Luminant believes that the relevant markets for CSAPR emissions allowances will be very "short" because demand will far exceed supply. In addition, CSAPR imposes "assurance levels" that effectively serve as caps on the number of emissions allowances

that Texas sources can import. Any emissions that exceed Texas's assurance level caps will have to be covered at a prohibitive penalty of three allowances for every one ton of excess emissions. The combination of the short markets for allowances, the assurance level caps requiring three-to-one retirements for excess emissions, and the severe reductions required in Texas will result in Luminant not being able to rely on a compliance strategy of purchasing allowances.

21. Finally, EPA's claim that EGUs in Texas will be able to comply with CSAPR through "increased dispatch of lower-emitting generation" to offset curtailed generation at other units and to remain within their budgets is incorrect. As discussed in the Declaration of Warren Lasher of ERCOT, during times of peak demand in Texas, all available generation is already running; thus, there is no support for EPA's suggestion that other lower-emitting units can simply be turned on to replace generation that is curtailed due to CSAPR. The same is true for Luminant in particular. We do not have other "lower-emitting" assets that can make up the loss of 1300 MW during times of peak demand caused by the idling of two units at the Monticello Plant and the derating of generation at other locations. Even running its lowest-emitting units, Luminant will still be forced to take the actions described above.

22. Table 2 summarizes the major process changes that Luminant examined as options for compliance with CSAPR starting January 1, 2012.

Table 2: Major Compliance Options Considered

Equipment or Action	Description	Luminant's Ability to Utilize Equipment or Action to Achieve 2012 Compliance
Fuel switching	Increase PRB percentage to enable SO_2 reduction	Luminant will be switching to 100% PRB at the Big Brown Power Plant and Monticello Power Plant Unit 3.
Generation curtailment or shutdown	Reducing generation or idling facilities to reduce SO_2 and NO_x	Luminant will be idling Monticello Power Plant Units 1 and 2 (approximately 1200 MW of capacity). Luminant will be reducing its remaining generation by an additional approximately 100 MW .
Dry Sorbent Injection	Injects a chemical sorbent into the flue gas stream to enable SO_2 removal	DSI is not a cost-effective compliance tool because fuel-switching diminishes effectiveness and DSI does not resolve NOx constraints.
Flue Gas Desulfurization	Utilizes a crushed limestone slurry to enable SO_2 removal	Luminant will implement FGD upgrades at 5 of its remaining EGUs, but new FGDs are not feasible for 2012 compliance because permitting, design, procurement and construction would take three years or more
Selective Catalytic Reduction	Utilizes a combination of catalyst and anhydrous ammonia to enable NO_x removal	Luminant cannot utilize in 2012, as permitting, design, procurement, and construction will take three years or more.
Selective Non-catalytic Reduction	Injects ammonia or urea into the flue gas stream to enable NO_x removal	Luminant will install SNCR technology at its Martin Lake Power Plant, but it will not be fully operational by January 1, 2012.
Purchasing Emissions Allowances	CSAPR sets up an emissions trading mechanism that allows the purchase of	Luminant expects the Texas market, and the market as a whole, to be very short of

	emissions allowances in lieu of emission reductions.	allowances, meaning that sufficient allowances will not be available to ensure compliance; furthermore, penalties for exceeding the Texas assurance levels foreclose purchasing a significant number of allowances as a viable compliance tool.

TIMELINE FOR IMPLEMENTING COMPLIANCE MEASURES

23. Luminant announced its compliance plan, absent a stay of the CSAPR compliance deadlines as to Texas, on September 12, 2011. Luminant has already started to take steps to execute on its compliance plan, because we must be prepared to comply with CSAPR starting January 1, 2012. As we move closer to January 1, 2012, many of Luminant's implementation measures will become irrevocable.

24. The company will need to place major equipment orders immediately in order to complete the planned scrubber upgrades and SNCR installations. Although negotiations with equipment vendors are still underway, it is possible that once equipment orders are placed, cancellation penalties will apply if Luminant changes course.

25. By October 3, 2011, Luminant will need to notify ERCOT of its expected reduction in generating capacity. Luminant is required by state law to make this notification regarding idling of generating units at least 90 days before taking such action.

26. By December, Luminant will stop mining lignite coal at the three mines that will be closed, as discussed in the declaration of Stephen Kopenitz.

27. As discussed in more detail in the declaration of Stephen Kopenitz, the company will need to notify employees of anticipated layoffs by early November and will start to lose employees before the end of the year.

28. December 31, 2011 will be the last day that Units 1 and 2 at the Monticello Power Plant produce electricity before going into idled status on January 1, 2012.

29. Layoffs at the EGUs will begin in early January, 2012. Notification of the layoffs at the mines will begin sooner, as early as November, 2011.

30. By early February, 2012, the first round of mining and plant employee reductions will be completed, resulting in a reduction of at least 400 employees by the end of the first quarter of 2012. Additional job losses will follow in subsequent years.

IRREPARABLE HARM CAUSED BY CSAPR

31. CSAPR will cause a cascade of harms to Luminant, to the communities in which Luminant operates, to the reliability of the ERCOT electricity grid, and to the state of Texas as a whole.

Idling of Generating Units and Cessation of Mining Operations

32. As discussed above, Luminant will be forced to idle two major electric generating units by January 1, 2012. Idling those facilities is necessary for compliance with CSAPR beginning January 1, 2012. I am cognizant of the harm posed to the ERCOT electricity grid by the reduction in generating capacity that will result from idling those units. Accordingly, we intend to continue to seek to identify and pursue options that might allow us in the future to restore generation levels at the units affected by CSAPR. However, electricity that could have been generated from these facilities during the idle period, and the associated revenue, will be forever lost to Luminant. Further, in order to

reopen these units, Luminant will be faced with the cost of idling the units and then restarting them.

33. As discussed in detail in the declaration of Stephen Kopenitz, Luminant will also be closing three mines as a result of CSAPR, including the Turlington mining area, which was only recently opened at a cost of approximately $80 million. The closure of those three mines will result in the loss of approximately 280 employees between late 2011 and early 2012 and an ultimate job loss of more than 400 employees. Mining will cease at these locations in early December, and Luminant will devote its efforts to reclaiming the mines thereafter.

<u>Loss of jobs</u>

34. The closure of the mines and the idling of two Monticello EGUs will require the elimination of at least 400 jobs by early 2012 and the eventual elimination of up to 500 jobs as the mine reclamation efforts are completed.

35. This will be a heavy blow to Luminant, its employees and its employees' families. In many cases, Luminant employees have been working for the company for decades and some families have multiple generations working for Luminant. In addition, these positions are some of the highest paying and most sought-after, stable jobs in the communities where they are located. It is unlikely that these workers will be able to find comparable jobs in their communities.

<u>Harm to communities</u>

36. Since Luminant dedicates significant efforts to being a supportive and active member of the communities in which it has facilities, there will be significant impacts on those communities from the reduction in operations that Luminant is forced to implement. The

impacted communities are rural Texas communities where Luminant is one of the largest taxpayers, employers, and community supporters.

37. I understand that community leaders are providing declarations that will explain many of the expected harms. But to give a sense of Luminant's contribution to those communities, I asked my staff to prepare Table 3. The table summarizes some of the ways that Luminant contributes to the communities that will be impacted by the closures.

Table 3 Luminant's 2010 Community Contributions

	Titus County (Monticello Plant & Mines)	**Freestone County (Big Brown Plant & Mines)**
2010 County Tax Paid	$3,326,752	$1,435,925
2010 School Tax Paid	$11,514,241	$7,067,989
2010 College Tax Paid	$984,407	N/A
2010 Hospital Tax Paid	$1,216,913	$205,816
2010 Charitable Donations	$48,650	$21,550
2010 Volunteer Hours	3,200	600

38. Although Luminant will continue to operate in these communities, Luminant's operations will be significantly reduced. Further, the value of Luminant's facilities, and therefore the amount of taxes paid, will also be substantially reduced. In addition, the dollars that Luminant employees spend in the communities will naturally be significantly reduced and any exodus from the communities will likely impact property values, further reducing the tax base of those communities.

39. The impacts from Luminant's reduced operations will ripple throughout these communities. For example, Luminant hires local and regional vendors to provide a range

of services and will have to curtail those expenditures, harming these vendors financially and possibly leading to further job losses. The loss of Luminant's direct and indirect jobs will also impact other local businesses, ranging from local restaurants to the locally-owned stores that sell Luminant employees and their families the things they need for daily living. For example, in just one year at the Monticello Plant, Luminant paid over $1.5 million in per diem expenses for contractors to use for their temporary living expenses in the local community. Moreover, when Luminant performs its annual maintenance on its power plants, it brings in hundreds of contract workers from various vendors for several weeks at a time. Spending by these contract workers is a major benefit to local restaurants, hotels and stores. The idling of two generation units will result in a significant reduction in visits to the local area by these contract workers.

<u>Loss of electricity generation</u>

40. Due to idling the two EGUs at Monticello, Luminant will be unable to provide approximately 1200 MW of generating capacity to the ERCOT market. In addition, it will be necessary to derate certain other EGUs to ensure that Luminant will be able to comply with CSAPR's Texas emissions budgets. And, as discussed in Ken Smith's declaration, certain plants will need to derate in order to address complications associated with switching to 100% PRB coal on units designed to burn lignite. These derates will result in another 100 MW of reduced peak generating capacity in ERCOT.

41. The reduction in generating capacity translates immediately into lost revenue for Luminant. Every moment that Luminant could be providing electricity to the grid but is restrained from doing so, represents lost sales of electricity. Since Luminant operates in a deregulated competitive energy market, there is no way that Luminant can recover that

lost revenue. Unlike some regulated utilities in other parts of the country, there is no option for Luminant to recover such lost revenues through an adjustment to a regulated rate.

Threat to grid reliability

42. As Texas's independent electric grid operator, ERCOT's job is to ensure the stability of the electricity grid in Texas. Luminant's coal plants, together with other coal-fueled generation in the state, provide approximately 40 percent of the electricity consumed in ERCOT.

43. The reduction of approximately 1300 MW from Luminant in 2012 along with any reductions by other producers will threaten the reliability of the grid in Texas. One megawatt is roughly enough electricity to power 500 average homes under normal conditions in Texas, or about 200 homes during hot weather when air conditioners are running for longer periods of time. Thirteen hundred MW would thus be enough to power 260,000 homes in the hot summer months and 650,000 during normal weather conditions. ERCOT has concluded that there would have been rolling blackouts in Texas as recently as August 4, 2011 if only an additional 300-500 MWs had been unavailable that day, which is far less capacity than the 1300 MWs that CSAPR will force Luminant to curtail. ERCOT's conclusions are consistent with Luminant's own internal analyses. Analysis by ERCOT indicates that the ERCOT system will face an increased risk of energy emergency events and, consequently, an increased risk of rolling blackouts because of reduced generation in 2012 that will result from CSAPR.

44. The demand for electricity in Texas has steadily increased in recent years. In each of the three years since 2009, ERCOT hit a new all-time peak demand. Notably, ERCOT set

three new demand records in early August this year. Similarly, the winter peak demand record has been broken in each of the last two winters.

45. Looking back at just this year, there have been a number of events threatening grid reliability. On February 2, 2011, the ERCOT region was forced into rolling blackouts resulting from extreme cold weather conditions, record electricity demand levels, and weather-induced failures at some electric generating facilities. During this summer's sustained heat wave, the grid has also experienced a number of emergency alerts, and ERCOT has issued numerous calls for conservation and interrupted power to certain industrial and commercial customers to avoid resorting to rolling blackouts. Sharply reducing supply during this time of steady demand growth presents a very real and severe risk to the reliability of the ERCOT grid.

Financial harm to Luminant

46. To comply with CSAPR in its first year, 2012, Luminant will be forced to take a number of measures that will increase the company's costs and decrease its revenues. In 2012, Luminant will idle two generating units and reduce generation at other units, close mines to change fuel sources to higher-cost fuels, increase costs for labor and routine maintenance for pollution control equipment, sever employees, reclaim mining operations sooner than expected and change or add significant capital equipment. As a result of these actions taken to comply with CSAPR, Luminant's coal generation fleet will produce and sell less electricity—on an annual basis, approximately 10 terawatt hours (TWh) less than it would have absent CSAPR. Combining the impact to revenue with CSAPR's impact on expenses results in a reduction of Luminant's 2012 EBITDA (Earnings Before Interest, Taxes, Depreciation and Amortization expense) of

approximately $260 million. Without lignite mining at the affected sites in the future, and with ongoing reduced generation, these impacts will persist beyond 2012 and the harm to the company will be measured in the billions of dollars. In addition, typically energy companies like Luminant are valued based on EBITDA multiples in the 7-9 range. Using this methodology for just the single-year 2012 EBITDA impacts, the estimated drop in that 2012 EBITDA due to CSAPR would reduce the company's enterprise value by $1.8 to $2.3 billion.

47. Luminant's cash flow will also be impacted by charges for employee severance, capital spending and other uses of cash resulting from complying with CSAPR. Severance costs will be approximately $35 million in 2012, and cash capital spending will increase roughly $110 million in 2011 and $170 million in 2012, largely for equipment to reduce SO_2 and NO_x emissions needed to comply with the CSAPR.

Increase in Electricity Prices

48. According to simple economics of supply and demand, Luminant's reduced supply of generation starting in 2012 likely will increase wholesale electricity prices in Texas. Luminant currently estimates that wholesale prices will increase by at least $3.00 per megawatt hour (MWh) on an average annualized basis. Approximately $1.70 of this $3.00 price increase is due to Luminant's anticipated reduction in generation, even if no other sources reduce generation as a result of CSAPR. The remaining $1.30 of the $3.00 price increase is due to the market impact of the allowance prices that EPA estimates for 2012. Even if Luminant's overall electricity supply portfolio experiences this price increase, however, it will not come close to offsetting Luminant's lost revenue. Naturally, higher wholesale prices in ERCOT will likely drive up retail prices for electricity.

Conclusion

49. On September 12, 2011, Luminant informed its employees of its plans to idle generating units and cease mining operations if we are unable to secure a stay of CSAPR. Shortly after notifying employees, Luminant issued a Securities Exchange Commission Form 8-K and a press release to inform its investors and the public about its compliance plans. These conversations and communications have been difficult but necessary steps in the process of preparing to comply with CSAPR on such a short timetable—again, steps that would not be necessary if EPA had given Texas and Luminant a reasonable time to comply.

50. Prior to initiating this litigation, I sought to exhaust every option that would avoid the closures, job losses, and other consequences described above. My overriding goal since the announcement of CSAPR has been to explore every avenue that would minimize these impacts and I view litigation as a last resort. To that end, I met with EPA to discuss Luminant's administrative request for reconsideration and the harms that are resulting from CSAPR. EPA officials made themselves available for high-level meetings during this time, and Luminant deferred filing this litigation as a result. In the discussions, in light of errors that Luminant brought to the agency's attention, EPA offered to make adjustments that would increase the number of allowances allocated to Texas. *See* Exhibit 1 attached hereto. While I appreciate EPA's willingness to consider adjustments, unfortunately the Agency has not adopted any adjustments or offered a timetable that would allow Luminant to avoid the harms described in this declaration. *See* Exhibit 2 attached hereto.

51. If compliance with CSAPR is required beginning on January 1, 2012, then Luminant must begin taking steps immediately to idle two of its generating units and cease operations at three of its lignite mines in order to comply. Luminant must also make plans to implement equipment changes and upgrades at most of its other coal-fueled units. These steps will cause irreparable and in many cases irreversible harms to Luminant, its employees and their families, the communities where Luminant operates, the ERCOT grid, and the State of Texas in general. For this reason, Luminant is asking the Court for a stay of CSAPR while Luminant's legal challenge is resolved. A stay is the only way to avoid the irreparable harms that will result if CSAPR is allowed to take effect as currently planned.

I, David A. Campbell, declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct. Executed this 14th day of September, 2011.

David A. Campbell