No. 16-____

IN THE SUPREME COURT OF THE UNITED STATES

STATE OF WEST VIRGINIA,
STATE OF TEXAS, *et al.*,

Applicants,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, and
REGINA A. MCCARTHY, Administrator,
United States Environmental Protection Agency

Respondents.

APPLICATION BY 29 STATES AND STATE AGENCIES FOR IMMEDIATE STAY OF FINAL AGENCY ACTION DURING PENDENCY OF PETITIONS FOR REVIEW

DIRECTED TO THE HONORABLE JOHN G. ROBERTS, JR., CHIEF JUSTICE OF THE UNITED STATES AND CIRCUIT JUSTICE FOR THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

APPENDIX A

CONTENTS

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 15-1363 **September Term, 2015**

EPA-80FR64662

Filed On: January 21, 2016

State of West Virginia, et al.,

Petitioners

v.

Environmental Protection Agency and Regina A. McCarthy, Administrator, United States Environmental Protection Agency,

Respondents

American Wind Energy Association, et al.,
Intervenors

Consolidated with 15-1364, 15-1365, 15-1366, 15-1367, 15-1368, 15-1370, 15-1371, 15-1372, 15-1373, 15-1374, 15-1375, 15-1376, 15-1377, 15-1378, 15-1379, 15-1380, 15-1382, 15-1383, 15-1386, 15-1393, 15-1398, 15-1409, 15-1410, 15-1413, 15-1418, 15-1422, 15-1432, 15-1442, 15-1451, 15-1459, 15-1464, 15-1470, 15-1472, 15-1474, 15-1475, 15-1477, 15-1483, 15-1488

BEFORE: Henderson, Rogers, and Srinivasan, Circuit Judges

O R D E R

Upon consideration of the motion for stay and expedition and the motions for stay, the responses thereto, and the replies; the joint motion to establish briefing format and expedited briefing schedule, the responses thereto, and the replies; and petitioner LG & E and KU Energy's motion in No. 15-1418 to sever certain issues and hold them in abeyance and the oppositions thereto, it is

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 15-1363 **September Term, 2015**

ORDERED that the motions for stay be denied. Petitioners have not satisfied the stringent requirements for a stay pending court review. See Winter v. Natural Res. Def. Council, Inc., 555 U.S. 7, 20 (2008); D.C. Circuit Handbook of Practice and Internal Procedures 33 (2015). It is

FURTHER ORDERED that consideration of these appeals be expedited. It is

FURTHER ORDERED that the motion in No. 15-1418 to sever certain issues and hold them in abeyance be denied. It is

FURTHER ORDERED, on the court's own motion, that by noon on January 27, 2016, the parties submit a proposed format for the briefing of all the issues in these cases, as well as a proposed schedule that ensures that all initial briefs are filed by April 15, 2016, the deferred appendix is filed by April 18, 2016, and the final briefs are filed by April 22, 2016. The parties are reminded that the court looks with extreme disfavor on repetitious submissions, and the parties are encouraged to limit both the number and size of the briefs they propose to file. It is

FURTHER ORDERED that oral argument be scheduled before this panel on June 2, 2016, commencing at 9:30 a.m. The parties should also reserve June 3 in the event argument cannot be concluded on June 2nd.

The parties are directed to hand-deliver the paper copies of their submission to the court by the time and date due.

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

BY:

John J. Accursio
Deputy Clerk/LD

Table of Illustrative State Activities Undertaken Since August 3, 2015, to Prepare State Plans Under the Clean Power Plan

State	Activity	Website
Alabama	• Autumn 2015 – Alabama Department of Environmental Management (ADEM) forms workgroup of utility stakeholders to receive comment on final Clean Power Plan (CPP). • September 24, 2015 – ADEM staff present on final CPP to Alabama Chapter of Air & Waste Management Association. • Autumn 2015 – ADEM staff participate in several national workshops and over a dozen conference calls and webinars on the CPP. • Autumn 2015 – ADEM staff meet with electric utilities to discuss CPP and its potential impacts.	
Arizona	• August 20, 2015 – Joint Legislative Review Committee on State Plans Relating to Carbon Dioxide Emissions from Existing Power Plants (JLRC) hosts meeting with Arizona Department of Environmental Quality (ADEQ), Arizona Corporation Commission (ACC), and Arizona utilities and the Electric Cooperative Association, and receives public comment. • September 1, 2015 – ADEQ hosts first stakeholder meeting on the final CPP to discuss the rule and next steps to meet the 2016 initial submittal deadline. ADEQ announces it is working with a group of 15 States to consider options for and interest in adopting a regional approach to state planning. A technical working group of stakeholders and Arizona State University are helping to complete analyses of state plan options. • September 24, 2015 – JLRC hosts meeting to consider the reliability of the electrical power grid, the availability of natural gas and related infrastructure, and the effects on the state and local economies with presentations from the ACC, ADEQ, Arizona Commerce Authority, Arizona Cattlemen's Association, Arizona Chamber of Commerce, and Greater Phoenix Chamber of Commerce. • October 6, 2015 – ADEQ hosts stakeholder meeting to discuss next steps to meet the 2016 initial submittal deadline. ADEQ announces that officials have been looking at other States' planning activities and linkage opportunities, and traveling to meetings in Denver and Philadelphia. ADEQ also announces it has met with the Navajo Nation on the CPP, and that ADEQ has formed a technical work group and a consultation group, in addition	http://www.azdeq.gov/environ/air/phasethree.html http://www.azleg.gov/FormatDocument.asp?inDoc=/icommittee/Joint+Legislative+Review+Committee+on+State+Plans+Relating+to+Carbon+Dioxide+Emissions+from+Existing+Power+Plants%2Edoc.htm http://www.azleg.gov/InterimCommittees.asp

State	Activity	Website
	to the large stakeholder meetings. • October 8, 2015 – Arizona CPP Technical Working Group meets. • November 3, 2015 – Stakeholder Working Group meets to discuss outreach to vulnerable communities and to review Work Plan for ADEQ completion of initial state plan submittal. • November 4, 2015 – ADEQ releases revised draft work plan for development of initial state plan. • December 2015 – Technical Working Group meets to identify compliance options that can be eliminated based on clear technical limitations. • December 2015 – ADEQ develops outreach program to vulnerable communities. • December 30, 2015 – ADEQ submits quarterly report to JLRC. • January 5, 2016 – ADEQ hosts stakeholder meeting to discuss state plan compliance options.	
Arkansas	• August 17, 2015 – Arkansas Department of Environmental Quality (ADEQ) and Arkansas Public Service Commission (APSC) host press conference on the final CPP. • October 9, 2015 – ADEQ and APSC host a joint meeting with stakeholders to discuss the CPP and to accept comments on a tentative strategy for state implementation. The tentative strategy document notes efforts will include continued multi-agency engagement, renewed and periodic stakeholder engagement, multi-agency and stakeholder engagement and participation in development of the assumptions and data fields comprising required assessments of the state plan (see below), engagement with the state General Assembly, and continued engagement with the Governor's office. • Act 382 requires ADEQ to work with the APSC and the Arkansas Economic Development Commission to conduct assessments of environmental, ratepayer, and economic impacts of a state CPP plan before it is submitted to the Arkansas Legislative Council and ultimately to EPA. The October 9, 2015 strategy document suggests the creation of committees to evaluate the three required assessment areas.	https://www.adeq.state.ar.us/air/planning/cpp/

State	Activity	Website
California	• September 28, 2015 – California Air Resources Board (ARB) staff releases Clean Power Plan Compliance Discussion Paper outlining overview of considerations in development of state plan, indicating that ARB will likely adopt a mass-based state measures plan incorporating the State's existing cap-and-trade regulatory program. • October 2, 2015 – ARB staff host public workshop with California Energy Commission and California Public Utilities Commission staff to explore issues in September 28 Discussion Paper and to discuss state plan for CPP compliance. • November 10, 2015 – ARB staff hold workshop on modeling approach to state plan. • November 19, 2015 – ARB staff provide informational update to ARB members. • December 1, 2015 – ARB staff announce commencement of environmental analysis under California Environmental Quality Act regarding potentially significant adverse environmental impacts from CPP and related potential amendments to state regulations. • December 14, 2015 – ARB staff hold workshop to discuss state CPP compliance plan policy options, modeling results, and the scope and schedule for potential amendments to existing state regulations relating to electricity sector emissions.	http://www.arb.ca.gov/cc/powerplants/powerplants.htm
Colorado	• August 3, 2015 – Colorado Department of Public Health and Environment (CDPHE) issues press release on final CPP and announces development of a stakeholder process. • September 25, 2015 – CDPHE hosts first stakeholder meeting to discuss process for developing state plan and to solicit public comment. • October 9, 2015 – CDPHE participates in Georgetown Climate Center dialogue on CPP implementation. • November 9, 2015 – CDPHE hosts second stakeholder opportunity to provide public comment on state plan development. • December 3, 2015 – CDPHE releases timeline for development of state CPP compliance plan, with seven focused stakeholder meetings planned for the first half of 2016. CDPHE announces it has received more than 50 oral and written public comments on the CPP, and requests additional comment on specific topics relating to the CPP. CDPHE also announces it is working with consultants to	https://www.colorado.gov/cdphe/CleanPowerPlan

State	Activity	Website
	develop a tool to screen CPP compliance scenarios and is evaluating options for modeling the electric grid and the costs of potential emission reduction strategies. • January 14, 2016 – CDPHE hosts stakeholder meeting to discuss impact of final CPP on urban low income communities and the Clean Energy Incentive Program element of the final CPP.	
Connecticut	• August 3, 2015 – Connecticut Department of Energy and Environmental Protection (DEEP) Commissioner announces launch of detailed review of final CPP to develop compliance plan. • August 28, 2015 – CT Governor's Council on Climate Change presents overview of final CPP to members of public. • October 9, 2015 – DEEP participates in Georgetown Climate Center dialogue on CPP implementation.	http://www.ct.gov/deep/cwp/view.asp?a=4707&Q=569096&deepNav_GID=1511
Delaware	• November 10, 2015 – Delaware Department of Natural Resources and Environmental Control (DNREC) and Delaware Public Service Commission host listening session, present on entities subject to regulation under the CPP, and indicate the State is likely to adopt a mass-based, multi-state approach consistent with the Regional Greenhouse Gas Initiative of which the State is a part. DNREC disseminates questions for stakeholder consideration. • December 31, 2015 – Deadline to submit public comments to DNREC on Delaware's compliance with the CPP.	http://www.dnrec.delaware.gov/Air/Pages/CleanPowerPlan.aspx
Florida	• August – December 2015 – Florida Department of Environmental Protection (DEP) staff undertake comprehensive review of final CPP, technical support documents, proposed model trading rules, and proposed federal plan released by EPA; staff participate in multiple webinars, informational calls, training sessions, and workshops, sponsored both by EPA and third-party organizations, relating to the CPP and related rules; staff meet weekly on CPP, state compliance plan, and proposed federal plan, accounting for over 1000 hours of staff time. • August – December 2015 – DEP staff participate in multiple in-person meetings with stakeholders, associations, and interest groups, including tour of regional utilities' power distribution center and trading floor. • August – December 2015 – DEP staff attend multiple conference calls with utility, industry, and interest group	

State	Activity	Website
	representatives to discuss CPP state plan development. September 24-25, 2015 – DEP staff participate in Nicholas Institute workshop in Durham, NC, to discuss state plan options and multi-state coordination. • October 20, 2015 – DEP Deputy Secretary briefs Florida Legislature on final CPP.	
Georgia	• September 24-25, 2015 – Georgia Environmental Protection Division (EPD) staff participate in Nicholas Institute workshop in Durham, NC, to discuss state plan options and multi-state coordination. • September 28, 2015 – EPD and Georgia Public Service Commission (PSC) staff participate in joint conference hosted by Georgia Tech School of Public Policy and Emory University's Climate@Emory initiative to discuss Georgia's options for implementing the CPP. • October 8, 2015 – EPD hosts stakeholder meeting on the CPP and announces development of an engagement plan. • October – December 2015 – EPD meets with stakeholders, including state agencies (PSC, Georgia Economic Finance Authority), utilities, and advocacy groups, to discuss state plan development. • October 27, 2015 – EPD participates in quarterly demand side management (DSM) work group session to inform state plan development (work group separately established by the PSC to inform triennial Integrated Resource Plan development). • November 12, 2015 – PSC hosts EPD and U.S. EPA officials at Energy Committee meeting to discuss CPP's treatment of biomass for compliance with emission targets. • November – December 2015 – EPD participates in EPA's CPP Clean Energy Incentive Program (CEIP) coordination calls. • December 8, 2015 – EPD establishes Steering Committee for Vulnerable Community Outreach as part of state plan development process. • December 9, 2015 – EPD participates in DSM work group web meeting as part of state plan development process. • December 15, 2015 – EPD submits comments to EPA regarding CPP CEIP.	https://epd.georgia.gov/air/111dstakeholdermeetings

State	Activity	Website
	• January 7, 2016 – EPD hosts stakeholder meeting to discuss whether the State should participate in the CEIP as part of its state plan. • January 19, 2016 – First meeting of Steering Committee for Vulnerable Community Outreach to discuss implementation of community outreach requirements for CPP state plan.	
Idaho	• Autumn 2015 – Idaho Department of Environmental Quality announces commencement of state plan development process in conjunction with Idaho Office of Energy Resources, the Idaho Public Utilities Commission, and other stakeholders.	http://www.deq.idaho.gov/air-quality/air-pollutants/greenhouse-gases/epa-clean-power-plan-rule/
Indiana	• August 20, 2015 – Indiana Department of Environmental Management (IDEM) hosts stakeholder meeting on CPP. • October 15, 2015 – IDEM official speaks on CPP at Indiana Energy Conference.	
Iowa	• September 9, 2015 – Iowa Department of Natural Resources (DNR) hosts stakeholder meeting on CPP to review the final rule, discuss the stakeholder process, and discuss initial impressions of the rule. • September 21, 2015 – DNR releases timeline for development of state plan. • November 16, 2015 – DNR hosts stakeholder meeting, including presentations on the CPP's impacts on regional transmission organizations, the Clean Energy Incentive Program, the proposed federal plan and model trading rules, and a discussion of mass vs. rate-based state plans. • January 14, 2016 – DNR hosts stakeholder meeting.	http://www.iowadnr.gov/Environmental-Protection/Air-Quality/Greenhouse-Gas-Emissions/Carbon-Pollution-Stnds-111d
Kansas	• Autumn 2015 – Pursuant to a July 2015 Memorandum of Understanding and HB 2233, Kansas Department of Health and Environment (KDHE) and Kansas Corporation Commission (KCC) to meet at least twice per month to develop a state plan to implement the CPP, to submit to the legislative Clean Power Plan Implementation Study Committee a plan to investigate, review, and develop the state plan by November 1, 2015, to conduct two sets of stakeholder meetings, and to submit to the legislature an outline of the CPP's requirements by February 1, 2016. • October 26, 2015 – KCC staff issue report and recommend to KCC the opening of a docket on the final CPP, specifically to conduct a comprehensive review of generation and dispatch options to identify least-cost	http://www.kdheks.gov/bar/caas111d/111d.html http://www.kcc.state.ks.us/pi/press/15-15.htm http://www.kcc.ks.gov/pi/public_comment.htm

State	Activity	Website
	compliance options. • November 13, 2015 – KCC opens docket on final CPP. • December 3, 2015 – KCC issues order to commence investigation of generation redispatch options to comply with final CPP, including to authorize staff to engage outside consultants. It also begins to accept public comment on final rule. • January 12, 2016 – KCC hosts open education session on CPP with KDHE and Attorney General's office. • January 30, 2016 – KCC staff to announce schedule for stakeholder hearings on final CPP.	
Kentucky	• October 27, 2015 – Kentucky Energy and Environment Cabinet Deputy Secretary speaks at Kentucky Energy Management Conference on State's plans to meet CPP requirements.	
Louisiana	• August 12, 2015 – Louisiana Public Service Commission (LPSC) requests public comment on final Clean Power Plan under Docket No. R-33253 by September 2, 2015 (deadline later extended to September 16, 2015). • September 23, 2015 – LPSC approves budget of $119,370 to retain outside consultant to assist in development of state CPP compliance plan.	http://lpscstar.louisiana.gov/star/portal/lpsc/page/docket-docs/PSC/DocketDetails.aspx?DocketId=1205dcc8-6985-4c34-bd60-d460b7733095
Michigan	• August 25, 2015 – Michigan Department of Environmental Quality (DEQ) announces the State will submit a state plan by September 6, 2016, and is assembling a stakeholder group to determine the most cost-effective compliance strategy. • October 9, 2015 – DEQ participates in Georgetown Climate Center dialogue on CPP implementation.	http://www.michigan.gov/deq/0,4561,7-135-3310_70310_70940-346460--,00.html
Minnesota	• August 3, 2015 – Minnesota Pollution Control Agency (MPCA) publishes notice in the State Register requesting public comment on possible rules for State's compliance with the CPP. • August 20, 2015 – MPCA announces commencement of drafting of rule language and statement of need and reasonableness to adopt state plan to implement CPP. • October 9, 2015 – MPCA participates in Georgetown Climate Center dialogue on CPP implementation. • November 17, 2015 – MPCA hosts stakeholder meeting to	http://www.pca.state.mn.us/index.php/air/air-permits-and-rules/air-rulemaking/clean-air-act-section-111dclean-power-plan-to-cut-carbon-pollution.html

State	Activity	Website
	discuss state activities on CPP.	
Mississippi	• Autumn 2015 – Mississippi Department of Environmental Quality (MDEQ) staff analyze impacts of final rule on State. • Autumn 2015 – MDEQ staff participate in numerous trainings and webinars on final CPP offered by U.S. EPA and independent entities, and participate in two regional consortiums analyzing and discussing impacts of the final CPP. • Autumn 2015 – MDEQ staff engage with individual stakeholders and other interested parties on final CPP. • October 8, 2015 – MDEQ hosts stakeholder meeting on final CPP. • October 16, 2015 – MDEQ staff present on CPP to Mississippi Manufacturers' Association. • November 16, 2015 – MDEQ and Public Service Commission staff meet to discuss final CPP and to schedule stakeholder and public outreach sessions. • December 4, 2015 – MDEQ staff meet with U.S. EPA Region 4 staff to discuss final CPP.	
Missouri	• September 23, 2015 – Missouri Department of Natural Resources (DNR) hosts stakeholder meeting to provide overview of the CPP. DNR announces participation in regular meetings, communication, and coordination with Missouri Department of Economic Development Division of Energy and Public Service Commission, 30-day public comment period on initial and final state plans, and additional stakeholder meetings. • December 2, 2015 – DNR hosts stakeholder meeting on the CPP's Clean Energy Incentive Program.	http://dnr.mo.gov/env/apcp/cpp/
Montana	• August 12, 14, 18, and 31, 2015, and September 4, 2015 – Montana Public Service Commission staff transmit analyses of different issues in final CPP to Commissioners. • October 9, 2015 – Montana Department of Environmental Quality (DEQ) participates in Georgetown Climate Center dialogue on CPP implementation. • November 12, 2015 – Montana Governor Steve Bullock issues Executive Order No. 18-2015 creating Interim Montana Clean Power Plan Advisory Council to gather	http://governor.mt.gov/Newsroom/ArtMID/28487/ArticleID/2168 http://leg.mt.gov/content/Committees/Interim/2015-2016/EQC/111d-Subcom/Meetings/Sept-2015/psc-111d-analysis.pdf

State	Activity	Website
	information and provide recommendations to the DEQ by July 2016 on CPP state plan options. • November 30, 2015 – Deadline to submit indications of interest to serve on Clean Power Plan Advisory Council.	
Nebraska	• August 2015 – Nebraska Department of Environmental Quality (NDEQ) commences outreach to stakeholder groups on final CPP. • Autumn 2015 – NDEQ staff meet monthly with representatives from public power sector to discuss CPP-related issues. • Autumn 2015 – NDEQ staff develop survey for individual, industry, and municipality stakeholders to generate appropriate materials for upcoming public meetings on CPP. • Mid-January 2016 – Public listening sessions with formal testimony on final CPP and state implementation to begin.	
Nevada	• November 12, 2015 – Nevada Public Utilities Commission, Governor's Office of Energy, and Nevada Division of Environmental Protection (DEP) host public hearing on CPP, present on the final rule and plan development process, and accept public comment from attendees on whether the State should submit a state plan or allow EPA to implement a federal plan, and if it is to develop a state plan, to describe the appropriate stakeholder development process and criteria the State should use to compare and evaluate compliance pathways. • December 31, 2015 – Deadline to submit written comments on CPP planning and implementation to DEP.	http://ndep.nv.gov/baqp/technical/CPP.html
New Hampshire	• October 14, 2015 – New Hampshire Department of Environmental Services (DES) and Public Utilities Commission of New Hampshire issue notice requesting public comments on state compliance with the CPP and revisions to Regional Greenhouse Gas Initiative, of which New Hampshire is a part. • November 20, 2015 – DES hosts stakeholder meeting to discuss CPP compliance options.	http://des.nh.gov/organization/divisions/air/tsb/tps/climate/rggi/documents/pubnotice-rggi-11-20-15.pdf
New Jersey	• Autumn 2015 – New Jersey Department of Environmental Protection updates website detailing actions relating to final CPP.	http://www.nj.gov/dep/111d/
New Mexico	• Autumn 2015 – New Mexico Environment Department (NMED) staff review final CPP and technical support	https://www.env.nm.gov/aqb/CPP.htm

State	Activity	Website
	documents released by EPA, participate in webinars, trainings and workshops related to the final CPP, and meet with stakeholders, including utilities, the Rural Electric Cooperative Association, environmental organizations, and other New Mexico citizens. NMED is also working with the City of Albuquerque Environmental Health Department, the New Mexico Energy, Minerals and Natural Resources Department, and the New Mexico Public Regulation Commission. NMED established a dedicated email address for the public to submit questions or comments on the CPP and New Mexico's compliance planning efforts. • November 18, 2015 – NMED hosts public listening session on the CPP and state plan development. • November 19, 2015 – NMED hosts public listening session on the CPP and state plan development. • December 4, 2015 – NMED hosts public listening session on the CPP and state plan development. • December 7, 2015 – NMED hosts public listening session on the CPP and state plan development. • December 8, 2015 – NMED hosts public listening session on the CPP and state plan development. • December 14, 2015 – NMED hosts public listening session on the CPP and state plan development. • January 11, 2016 – NMED hosts public listening session on the CPP and state plan development. • January 12, 2016 – NMED hosts public listening session on the CPP and state plan development.	https://www.env.nm.gov/aqb/CPPPublicOutreach.htm
New York	• October 9, 2015 – New York Assistant Commissioner for Air Resources, Climate Change and Energy participates in Georgetown Climate Center dialogue on CPP implementation. • December 15, 2015 – Department of Environmental Conservation submits comments to EPA on CEIP.	http://www.dec.ny.gov/energy/97799.html
North Carolina	• August 18, 2015 – North Carolina Department of Environment and Natural Resources (NCDENR) holds special information session on the final Clean Power Plan. • October 23, 2015 – NCDENR Division of Air Quality releases draft proposed regulations to implement the CPP, along with a 224-page Supporting Basis document, and an	http://www.ncair.org/rules/EGUs/ http://www.ncair.org/rules/hearing

State	Activity	Website
	18-page Fiscal Impact Summary. • November 16, 2015 – Public comment period on draft regulations begins. • December 16, 2015 – NCDENR Division of Air Quality holds public hearing on final CPP. • December 17, 2015 – NCDENR Division of Air Quality holds public hearing on final CPP. • January 5, 2016 – NCDENR Division of Air Quality holds public hearing on final CPP. • January 15, 2016 – Public comment period on draft regulations ends.	
North Dakota	• October 13, 2015 – North Dakota Department of Health (NDDoH) solicits public comment on CPP compliance options. • November 9, 2015 – NDDoH hosts public meeting on state plan development. • November 12, 2015 – NDDoH hosts public meeting on state plan development. • November 16, 2015 – NDDoH hosts public meeting on state plan development. • November 18, 2015 – NDDoH hosts public meeting on state plan development. • November 24, 2015 – State legislative Energy Development and Transmission Committee hosts hearing on final CPP with testimony from NDDoH officials. • December 18, 2015 – Deadline to submit public comments to NDDoH on state plan options; NDDoH hosts public meeting on state plan development.	http://www.ndhealth.gov/aq/publiccom.aspx http://www.ndhealth.gov/aq/cleanpowerplan.aspx
Ohio	• Autumn 2015 – Ohio Environmental Protection Agency (EPA) establishes dedicated email address to receive comments, concerns, and information on the CPP and state plan. • November 18, 2015 – Ohio EPA official speaks about the State's CPP-related activities at a conference hosted by Ohio Advanced Energy Economy. • December 2, 2015 – Ohio EPA and Public Utilities Commission of Ohio (PUCO) host information session for	http://epa.ohio.gov/dapc/111drule.aspx

State	Activity	Website
	interested parties to explain CPP requirements, a stakeholder engagement plan, and to answer initial questions. • Early 2016 – Ohio EPA hosts five regional listening sessions to provide public, interested parties, and stakeholders an opportunity to submit verbal and written testimony.	
Oklahoma	• Autumn 2015 – Oklahoma Department of Environmental Quality (DEQ) collects information and comments to assist in commenting on EPA's model rules for state plans and the proposed federal plan. • November 17, 2015 – DEQ hosts CPP Issues Technical Stakeholder Meeting.	http://www.deq.state.ok.us/aqdnew/RulesAndPlanning/cleanpower111d/index.htm
Oregon	• Autumn 2015 – Oregon Department of Environmental Quality announces it will work with Oregon Department of Energy, the Public Utility Commission, and regional stakeholders to begin developing state plan.	http://www.deq.state.or.us/aq/climate/co2standard.htm
Pennsylvania	• September 9, 2015 – Pennsylvania Department of Environmental Protection (DEP) conducts webinar about the CPP. • September 15, 2015 – DEP hosts listening session. • September 21, 2015 – DEP hosts listening session. • September 22, 2015 – DEP hosts two listening sessions. • September 28, 2015 – DEP hosts listening session. • September 30, 2015 – DEP hosts two listening sessions. • October 5, 2015 – DEP hosts listening session. • October 22, 2015 – DEP hosts listening session. • October 28, 2015 – DEP hosts listening session. • October 29, 2015 – DEP hosts listening session. • October 30, 2015 – DEP hosts two listening sessions. • November 4, 2015 – DEP hosts listening session. • November 12, 2015 – Deadline to submit comments to DEP on how the State should approach a state plan, including answers to 21 questions regarding whether Pennsylvania should adopt a rate- or mass-based pan, how	http://www.dep.pa.gov/Business/Air/BAQ/ClimateChange

State	Activity	Website
	allowances should be allocated under a mass-based approach, how new natural gas plants should be included under a mass-based target, and what methods should be used to measure compliance. • November 30, 2015 – DEP Secretary announces commencement of first draft of state CPP compliance plan, with goal to submit final plan to EPA in September 2016.	
Rhode Island	• September 17, 2015 – Rhode Island Department of Environmental Management hosts meeting of Executive Climate Change Committee Coordinating Council to discuss final Clean Power Plan.	www.planning.ri.gov/documents/climate/2015/schedule_2015.pdf
South Carolina	• November 12, 2015 – South Carolina Department of Health and Environmental Control (DHEC) and State Energy Office host public engagement session on the State Energy Plan and the final CPP. • November 19, 2015 – DHEC and State Energy Office host public engagement session on the State Energy Plan and the final CPP. • December 1, 2015 – DHEC and State Energy Office host public engagement session on the State Energy Plan and the final CPP. • December 10, 2015 – DHEC and State Energy Office host public engagement session on the State Energy Plan and the final CPP.	http://www.scdhec.gov/HomeAndEnvironment/Air/CleanPower/
South Dakota	• August-October 2015 – South Dakota Department of Environment and Natural Resources (DENR) hosts meetings with electric utilities to discuss final CPP. • November 19, 2015 – DENR briefs Board of Minerals and Environment on final CPP and presents timeline for state plan development and stakeholder engagement.	http://denr.sd.gov/boards/2015/bme1115pktsup.pdf
Tennessee	• October 9, 2015 – Tennessee Department of Environment and Conservation (TNDEC) participates in Georgetown Climate Center dialogue on CPP implementation. • December 16, 2015 – Tennessee General Assembly Joint Government Operations Committee holds status hearing on the final Clean Power Plan, including witness from TNDEC.	
Utah	• October 7, 2015 – Utah Air Quality Board presents on final CPP and announces stakeholder meetings.	

State	Activity	Website
Virginia	• August 13, 2015 – Virginia Department of Environmental Quality (DEQ) launches 60-day period to accept informal public comment on the CPP. • September 16, 2015 – DEQ hosts listening session to gather input from the public to help inform the Commonwealth's review and implementation of the CPP. • September 22, 2015 – DEQ hosts listening session to gather input from the public to help inform the Commonwealth's review and implementation of the CPP. • September 28, 2015 – DEQ hosts listening session to gather input from the public to help inform the Commonwealth's review and implementation of the CPP. • September 30, 2015 – DEQ hosts listening session to gather input from the public to help inform the Commonwealth's review and implementation of the CPP. • October 1, 2015 – DEQ hosts listening session to gather input from the public to help inform the Commonwealth's review and implementation of the CPP. • October 6, 2015 – DEQ hosts listening session to gather input from the public to help inform the Commonwealth's review and implementation of the CPP. • October 2015 – DEQ creates stakeholder group to advise the Commonwealth on CPP state plan development. • October 9, 2015 – Deputy Secretary for Natural Resources and DEQ participate in Georgetown Climate Center dialogue on CPP implementation. • October 23, 2015 – DEQ forms stakeholder group to discuss elements of state compliance plan for CPP. • November 12, 2015 – DEQ hosts first stakeholder group meeting to discuss benefits and issues of adopting a state performances standards plan versus a state measures plan. • December 15, 2015 – DEQ hosts second stakeholder group meeting to discuss the general mechanism to use to implement the preferred compliance plan. • January 22, 2016 – DEQ hosts third stakeholder group meeting.	http://www.deq.virginia.gov/Programs/Air/GreenhouseGasPlan.aspx http://www.deq.virginia.gov/Portals/0/DEQ/Air/Planning/listening%20session%20notice.pdf
Washington	• August 26, 2015 – Washington Department of Ecology (Ecology) hosts listening session to present overview of final CPP, to take comment on stakeholder and public	http://www.ecy.wa.gov/climatechange/cleanpowerplan.htm

State	Activity	Website
	engagement process, and to take poll on five most important topics related the CPP for Ecology to engage with the public on. • Autumn 2015 – Ecology announces drafting of state compliance plan in partnership with the Department of Commerce and the Utilities and Transportation Commission. Ecology also announces the creation of technical workgroups and the scheduling of meetings with industry, tribes, local governments, environmental groups, and the public. • October 9, 2015 – Office of Governor participates in Georgetown Climate Center dialogue on CPP implementation. • November 10, 2015 – Washington Department of Commerce hosts Technical Work Group meeting to discuss existing CPP analyses and analytical tools and to discuss the need for additional analyses of the rule.	
West Virginia	• August 18, 2015 – West Virginia Department of Environmental Protection (DEP) submits request to coal-fired electric generating units in West Virginia to submit by October 1, 2015, data and information regarding unit-specific impacts of the final CPP in both a rate-based and mass-based compliance scenario, detailing consumer impacts, nonair quality health and environmental impacts, projected energy requirements, market-based considerations, the costs of achieving emission reductions due to factors such as plant age, location or basic process design, physical difficulties with or any apparent inability to feasibly implement certain emission reduction measures, the absolute cost of applying the performance standard to the unit, the expected remaining useful life of the unit, the impacts of closing the unit, including economic consequences such as expected job losses, impacts on reliability of the system, and any other factors specific to the unit that make application of a modified or less stringent standard or a longer compliance schedule more reasonable. • October 16, 2015 – DEP announces it is working on a feasibility study related to the CPP and is accepting public comment and data on the study and the state plan through December 31, 2015. The feasibility study is mandated by House Bill 2004 to be completed within 180 days of the CPP's publication (or by April 20, 2016), and is being undertaken with the assistance of researchers from Marshall University. The feasibility study will examine the potential impacts to the State, its people, and the economy from adopting a state plan, as well as options for the State	http://www.dep.wv.gov/pio/Pages/Clean-Power-Plan.aspx

State	Activity	Website
	to meet the requirements of the CPP. • October 27, 2015 – Governor Earl Ray Tomblin issues statement indicating preference to submit initial compliance plan by September 6, 2016.	
Wisconsin	• Autumn 2015 – Public Service Commission of Wisconsin (PSCW) and Wisconsin Department of Natural Resources staff meet weekly to discuss CPP matters. PSCW staff update economic modeling developed for the proposed CPP. • October 16, 2015 – PSCW Chair discusses impacts of final CPP on State to Municipal Electric Utilities of Wisconsin. • November 12, 2015 – PSCW Chair discusses impacts of final CPP on energy prices and reliability and compliance challenges and opportunities to Wisconsin Manufacturers and Commerce Clean Air Act Conference.	
Wyoming	• August 3, 2015 – Wyoming Department of Environmental Quality announces commencement of analysis and review of final CPP.	http://deq.wyoming.gov/admin/news/deq-statement-over-clean-power-plan

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

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ______

DECLARATION OF KEITH BAUGUES,
ASSISTANT COMMISSIONER, INDIANA DEPARTMENT OF ENVIRONEMNTAL MANAGMEMENT

I, Keith Baugues, declare as follows:

1. I am the Assistant Commissioner of the Office of Air Quality (OAQ) for the Indiana Department of Environmental Management (IDEM). I have been the Assistant Commissioner of OAQ for over five (5) years. I have forty-two (42) years of experience working on air pollution issues, including six (6) years with the Indiana Air Pollution Control Division, nine (9) years with the U.S. Environmental Protection Agency, eight (8) years with the Office of Air Quality Planning and Standards and twenty two (22) years as environmental consultant in Illinois, Texas, Colorado and Indiana. As the Assistant Commissioner of OAQ, I have personal knowledge and experience to understand what steps IDEM has taken and will need to undertake in response to the Environmental Protection Agency's *Carbon Pollution Emission*

Guidelines for Existing Stationary Sources: Electric Utility Generating Units, published on the EPA website on August 3, 2015 (Section 111(d) Rule). EPA-HQ-OAR-2013-0602, available at http://www.epa.gov/airquality/cpp/cpp-final-rule.pdf. The final Section 111(d) Rule sets a deadline of September 6, 2016 for submitting initial plans, with the final deadline for a complete plan, with all legislative authority required to implement the plan, in place by September 6, 2018.

2. I submit this declaration for the purpose of describing the efforts of the State of Indiana to prepare to implement the Section 111(d) Rule since the Declaration of IDEM Commissioner Thomas Easterly was submitted in this case.

3. To date, we have taken the following steps:

a. We have held two (2) stakeholder meetings to update stakeholders regarding the Section 111(d) Rule and gain their input.

b. We have formed a working group consisting of representatives of IDEM, the Governor's Office, the Indiana Office of Energy Development, the Indiana Utility Regulatory Committee, and the Indiana Office of the Utility Consumer Counselor. The purpose of these meetings has been to prepare for the new costs, plans, rules and legislation that are likely to be needed as the result of the Section 111(d) Rule, if it passes judicial muster. We have had three (3) meetings so far.

c. We are preparing modeling analyses to be done by the Indiana State Utility Forecasting Group. The purpose of this work is to determine the potential effects of various strategies that might meet the Section 111(d) Rule, such as increased utility rates, lost jobs, closure of utilities and the cost of new infrastructure.

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

Executed on this 13th day of October in Indianapolis, Indiana.

Keith Baugues

Keith Baugues
Assistant Commissioner
Office of Air Quality
Indiana Department of Environmental Management

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

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al*., Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY Respondents.	Case Nos. _______

DECLARATION OF DAVID L. BRACHT, DIRECTOR,
NEBRASKA ENERGY OFFICE

I, David L. Bracht, declare as follows:

1. I am the Director of the Nebraska Energy Office ("NEO"). I have been employed at the NEO since January 2015. I have over 30 years of business, government and legal experience, including as a senior executive in private industry and government agencies and, for the last 10 years, as a private practice attorney working in the energy industry. As part of my duties, I have authority to monitor, track, and interact with stakeholders and regulators on the development

and implementation of state and federal environmental rules impacting public utilities.

2. I have personal knowledge to understand what steps Nebraska has taken and will likely need to take in response to the EPA's Section 111(d) Rule, including future resource planning for system reliability. In general, the Section 111(d) Rule will dramatically transform the way electric power will be generated and transmitted to consumers in Nebraska and throughout the United States. The Rule will, at the very least, require the construction of new power generation and transmission facilities and associated infrastructure, the updating or decommissioning of existing power generation and transmission facilities that are not fully depreciated, and changes to the electric power system that will affect the availability, cost and reliability of electric power for every single current and future consumer. In short, the Section 111(d) Rule will transform the American energy economy.

3. Based on my work experience and position, I have determined that implementing the Section 111(d) Rule will be a complicated, time consuming, and expensive endeavor, which will require the expenditure of substantial State resources, immediately and over the next calendar year.

4. Significant NEO resources have already been invested to understand and evaluate the proposed 111(d) Rule. NEO employees have spent approximately

375 hours understanding the rule and preparing for implementation, including outreach to Nebraska stakeholders, organizing stakeholder meetings and listening sessions, participating in regional collaboratives such as the National Association of State Energy Officials and the Midwest Energy Efficiency Association with other states and industry participants, and in-depth analysis of the impact of the Section 111(d) Rule on the state and regional systems.

5. NEO employees and consultants will be required to spend additional time and resources modeling the changes made from the proposed to the final Section 111(d) rule. The purpose of this model will be to forecast the cost of the changes in the Nebraska utility market that are necessary to comply with the Section 111(d) Rule, and the resulting impact on electric rates and overall economic growth.

6. Based on my knowledge and experience, the Section 111(d) Rule represents an unprecedented infringement by the EPA on the traditional authority of Nebraska to manage energy resources within our jurisdiction because the mandates of the Section 111(d) require NEO to undertake specific changes to how energy is provided to consumers. The Section 111(d) Rule also disrupts the well-settled division of authority over electricity markets under the Federal Power Act, and raises significant uncertainty about the role of the Federal Energy Regulatory Commission to ensure the reliability of electricity through the wholesale market.

7. Because compliance planning must begin immediately, it is important that this Court grant the States' Petition for Review. The system-wide changes necessary for compliance must be gradual to preserve reliability of the electric grid. Because compliance is calculated based on a rolling average, the longer Nebraska waits to begin compliance, the more expensive and difficult it will be to meet the requirements of the Rule.

8. Similarly, evaluation of specific compliance measures, such as new facilities or retirements, must also begin immediately. The lengthy application and approval process for utilities to construct, upgrade, or retire facilities to comply with the Section 111(d) Rule, as well as the in-depth evaluation of public necessity and convenience for each facility, requires utilities to plan and submit applications for upgrades almost immediately after publication of the final Section 111(d) Rule in order to have equipment constructed, upgraded, or decommissioned before the compliance period begins in 2022.

9. The NEO will need to spend approximately 850 hours over the next calendar year as a direct result of the Rule. The expenditure of these resources must begin immediately. This process includes the development of studies required by state statute to evaluate and estimate the impact on rates and reliability, and the resulting impact on economic development caused by potential retirements and replacements of generation and transmission facilities.

10. The Section 111(d) Rule will also severely threaten reliability and increase the cost of electricity by forcing Nebraska to move immediately toward reliance on a limited number of fuel sources. The risks associated with this type of system-wide transformation will occur in the next year, unless the Rule is stayed. The threats posed by this shift in resources and transformation of Nebraska's existing power system are particularly significant in the more sparsely populated rural areas of Nebraska that have limited transmission capabilities. The rural areas will also face a significant economic burden due to more limited tax base and the distributed nature of Nebraska's public power system. Nebraska's relatively small total population will also limit the resources available for implementing this significant change, thereby increasing the impact on ratepayers resulting in a negative impact on the entire state economy.

11. Changes made for the sake of compliance with the Section 111(d) Rule immediately and over the next calendar year will be irreversible and will impact the electric grid for decades. System planning is typically based on the 30-40 year lives of generation and transmission facilities. Building, redesigning, and adjusting power generation facilities takes years, and decisions made in these areas are often irreversible once they are made. For example, the decision to prematurely retire an electric generating unit could have significant consequences for system reliability and may unnecessarily increase costs to ratepayers for

decades to come. This is particularly true because of Nebraska's relatively small total population and the significant areas of the state that are sparsely populated.

12. The implementation of the Section 111(d) Rule will require legislative and constitutional changes on the state level that may permanently alter the daily operation of utilities. In order to meet the significant reductions under the Section 111(d) Rule, Nebraska will likely be forced to implement control measures outside of the physical location and control of electric generating units, such as end-use energy efficiency (reduced energy use by electricity consumers), demand response (usage changes according to instantaneous market and load-profile changes), and increased distributed generation (such as small residential renewable installations). While such "outside" control measures are not expressly required under the Section 111(d) Rule, they appear unavoidable and will require Nebraska to immediately set in motion the chain of events, including statutory changes, larger investment in customer-side behavior, and further rate restructuring, in order for these compliance options to contribute to the Section 111(d) Rule's emission reduction targets.

13. Nebraska is the only state in which 100% of electric power is provided by municipalities, public power districts and electric cooperatives. The 167 independent public power entities in Nebraska have separate boards of directors, in most cases elected by the local ratepayers. Imposing the top-down control will disrupt and undermine Nebraska's commitment to local public control that has

proven valuable over its 80 year history. Undertaking these measures will seriously disrupt the State's sovereign priorities, which would otherwise be devoted to addressing other pressing issues of public concern.

14. If Nebraska chooses to adopt a multi- state approach to complying with the Section 111(d) Rule, changes to rights and responsibilities of entities such as Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs") will be immediately and long lasting. If Nebraska joins in a multi-state compliance approach, it is likely to take the form of credit trading or an induced carbon price through the RTO. The members of these organizations must follow a prescribed stakeholder process to effect the changes, and Nebraska must agree to grant certain enforcement powers to those organizations. The stakeholder process and any necessary institutional changes for these organizations will likely need to be completed before a plan relying on those third parties can be submitted for approval to the EPA. These processes are lengthy, difficult to reverse once established, and will require immediate expenditure of resources over next calendar year.

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

Executed on October 14, 2015.

David L. Bracht

David L. Bracht
Director, Nebraska Energy Office

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

State of West Virginia, et al., Petitioners, **v.** **United States Environmental Protection Agency, et al.,** Respondents.	Case No. 15-1363 (and consolidated cases)

DECLARATION OF EDITH CHANG,

DEPUTY EXECUTIVE OFFICER OF THE CALIFORNIA AIR RESOURCES BOARD

I, Edith Chang, declare:

1. I am a Deputy Executive Officer of the California Air Resources Board (ARB), which is the agency charged with implementation of the federal Clean Power Plan in the state of California. I hold a B.S. in Mechanical Engineering from the University of California, Berkeley, and an M.S. in Mechanical Engineering from the University of California, Irvine and am a registered Mechanical Engineer in the State of California. I have more than twenty years of experience at ARB, and have worked on a wide variety of projects, including

implementation of ARB's zero-emission vehicle program, preparation of State Implementation Plans, and diesel incentive programs. My current responsibilities include overseeing ARB's Cap-and-Trade program, and our Clean Power Plan compliance strategy. This Declaration is based upon my experience managing Clean Air Act programs for California.

2. The purposes of this declaration are to: (i) discuss the serious harms that climate change caused, in part, by power sector emissions, is causing and will continue to cause to California unless those emissions are reduced, (ii) demonstrate California's need for greenhouse gas emissions reductions from the power sector; (iii) describe California's success in reducing these and other emissions through state planning, and to compare those planning efforts with the Clean Power Plan's requirements for state compliance plans; and (iv) explain the ways in which California's regulatory efforts will benefit from continued implementation of the Clean Power Plan and the denial of a stay.

I. Climate Change Threatens California, Requiring Immediate Greenhouse Gas Pollution Reductions

3. ARB and the state of California are committed to reducing greenhouse gas emissions in all sectors because climate change poses a pressing threat to public health and prosperity in our state, as well as throughout the world. California's

Office of Environmental Health and Hazards Assessment, for instance, has concluded that climate change is having increasingly negative effects on our state.[1] These effects include:

•A marked increase in extremely hot weather, resulting in increased deaths associated with heat waves. Hotter weather, including increases in extremely hot days, also contributes to ground-level ozone (or "smog") formation, which is linked to asthma, heart attacks, and pulmonary problems, especially in children and the elderly. Smog also reduces visibility, damages crops, and harms wildlife.

• Severe drought and the continuing collapse of the Sierra Nevada snowpack, which is a critical water supply source for California. Indeed, researchers have recently reported that the snowpack recently hit a 500-year low.[2] The drought has already been linked to climate change, [3] and the long-term trend for the

---

[1] *See* California Office of Environmental Health and Hazards Assessment, *Indicators of Climate Change in California* (2013), available at: http://oehha.ca.gov/multimedia/epic/pdf/ClimateChangeIndicatorsReport2013.pdf

[2] *See* Monte Morran, "Sierra Nevada Snowpack Is Much Worse Than Thought: A 500-Year Low," *Los Angeles Times*, (Sept. 14, 2015), available at: http://www.latimes.com/science/sciencenow/la-sci-sn-snowpack-20150911-story.html

[3] *See* Justin Gillis, "California Drought is Made Worse by Global Warming, Scientists Say," *New York Times* ("Global warming caused by human emissions has most likely intensified the drought in California by 15 to 20 percent, scientists said …. The odds of California suffering droughts at the far end of the scale, like the current one that began in 2012, have roughly doubled over the past century,

state under worsening climate change points to increasingly severe drought conditions.[4] As a result of the vanishing snowpack and statewide drought, Californians have been forced to significantly curtail water usage, with very substantial economic consequences. Already, California agriculture is experiencing major challenges as a result of the drought,[5] and continued severe drought will imperil both our agricultural sector and our economy generally.

• An increase in the severity and size of wildfires, with resulting lives lost, property damage, air quality harm resulting from the smoke (including from fine particles in the ash), and water quality risks from denuded slopes. This past summer, California experienced some of the most serious wildfires in its history, destroying large portions of entire towns, and many of these fires

---

they said."), available at: http://www.nytimes.com/2015/08/21/science/climate-change-intensifies-california-drought-scientists-say.html?_r=0

[4] *See id. See also* California Department of Water Resources, "Climate Change," ("Warmer temperatures will cause what snow we do get to melt faster and earlier, making it more difficult to store and use. By the end of this century, the Sierra snowpack is projected to experience a 48-65 percent loss from the historical April 1st average. This loss of snowpack means less water will be available for Californians to use. Climate change is also expected to result in more variable weather patterns throughout California. More variability can lead to longer and more severe droughts."), available at: http://www.water.ca.gov/climatechange/

[5] *See, e.g.*, Dale Kasler, "More California farmland could vanish as water shortages loom beyond drought," *Sacramento Bee* (Nov. 26, 2015), available at: http://www.sacbee.com/news/state/california/water-and-drought/article46665960.html

continued to burn into the autumn. Scientists project increased wildfire risk from climate change in the future.[6]

• Rising sea levels. The ocean has already risen between 6 to 8 inches along the California coast, and much larger increases have been predicted globally over the next century.[7] Sea level rise threatens low-lying cities and infrastructure throughout the state, including the Sacramento/San Joaquin Delta, which is the core of the state's water infrastructure.

• Ocean warming and acidification. In addition to warming of the ocean due to climate change, CO_2 absorbed by the ocean is increasing the acidity of ocean water.[8] This has very negative consequences for California's fisheries

[6] *See*, Joshua Emerson Smith, "Wildfire risk to rise by six times, study says," *San Diego Union Tribune* (Nov. 8, 2015) ("Climate change will steadily amplify the risk of wildfires in California by six-fold, according to the study, which is published in the current issue of the Bulletin of the American Meteorological Society. The report's authors more specifically quantified increases in extreme fire conditions linked to climate change, a connection that many other researchers had established over the years but in broad terms."), available at: http://www.sandiegouniontribune.com/news/2015/nov/08/wildfires-california-climate-change-yoon-gillies/ ; *see also* Union of Concerned Scientists, *Science Connections: Western Wildfires and Climate Change*, available at: http://www.ucsusa.org/sites/default/files/legacy/assets/documents/global_warming/Infographic-Western-Wildfires-and-Climate-Change-Methodology-and-Assumptions.pdf.

[7] *See Intergovernmental Panel on Climate Change*, "FAQ 5.1: Is Sea Level Rising?" available at: https://www.ipcc.ch/publications_and_data/ar4/wg1/en/faq-5-1.html.

[8] *See*, *e.g.*, Nicolas Gruber *et al.*, *Rapid Progression of Ocean Acidification in the California Current System*, Science Express (2012), available at:

and coastal wildlife. Changing ocean conditions have already contributed to a toxic algal bloom that led California to close its lucrative crab fishery this year.[9] We have also seen record strandings of starving marine mammals this year, as warmer waters and changing ocean conditions makes it difficult for them to survive.[10]

4. These are just a sampling of the negative effects California is experiencing. In many regards, climate change, caused by greenhouse gases, threatens the public health and welfare of all Californians. Addressing this issue requires immediate, sustained, and deep cuts to greenhouse gas emissions, including from electric power plants.

5. I have reviewed the discussion of climate change and its impacts in the preamble to U.S. EPA's final "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (the "Clean Power Plan"). U.S. EPA's description of a wide range of scientific studies demonstrating that greenhouse gases endanger public health and welfare is well supported, and is

---

https://www.oceanfdn.org/sites/default/files/Rapid%20Progression%20of%20Ocean%20Acidifcation%20in%20the%20California%20Current%20System.pdf

[9] *See* Azure Gilman, "A California crab ban reveals trouble in the Pacific Ocean," *Al Jazeera America* (Nov. 6, 2015), available at: http://america.aljazeera.com/articles/2015/11/6/a-california-crab-ban-reveals-troubled-pacific-ocean.html

[10] *See* Marine Mammal Center, "Unusual Ocean Conditions Continue to Cause Record Strandings" (Nov. 19, 2015), available at: http://www.marinemammalcenter.org/about-us/News-Room/2015-news-archives/record-strandings.html

consistent with California's experience and conclusions. I fully concur with U.S. EPA's analysis, including its finding that "climate change impacts touch nearly every aspect of public welfare" and that "[c]hildren, the elderly, and the poor are among the most vulnerable to … climate-related health impacts."

6. The National Academies of Science,[11] the U.S. Global Change Research Program,[12] and the Intergovernmental Panel on Climate Change,[13] are among the many scientific bodies that have concluded that there is a limited amount of time left to reduce emissions to safe levels. This is, in part, because carbon dioxide, the principal greenhouse gas, persists in the atmosphere for centuries. As a result, every year of additional greenhouse gas emissions results in persistent climate disruption for years to come. Conversely, the earlier we begin to reduce emissions, the more limited future damage from climate change is likely to be.

7. In light of these very serious risks, and the closing window of opportunity to address them, California has long been focused on reducing greenhouse gas emissions. California's Global Warming Solutions Act, AB 32, is one of several statutes directing ARB and other state agencies to take action. It recognizes this

[11] *See generally* National Academies of Science, *American's Climate Choices* (2011), available at: http://dels.nas.edu/Report/America-Climate-Choices-2011/12781.

[12] *See generally* U.S. Global Change Research Program, *National Climate Assessment* (2014), available at: http://nca2014.globalchange.gov/.

[13] *See generally* Intergovernmental Panel on Climate Change, *Climate Change 2014: Synthesis Report*, *Summary for Policymakers* (2014), available at: http://www.ipcc.ch/pdf/assessment-report/ar5/syr/AR5_SYR_FINAL_SPM.pdf

"serious threat" and directs California, and ARB, to support "other states, the federal government, and other countries" as they act to address emissions. *See* Cal. Health & Saf. Code §38501. This effort, supported by California Governors from both major political parties, involves agencies across state government and a wide range of programs.

8. California is currently on track to reduce total greenhouse emissions from all sectors to 1990 levels by 2020. Consistent with available science, California will then pursue emission reductions of 40% below 1990 levels by 2030, and 80% below 1990 levels by 2050.[14]

9. California's emissions reductions experience demonstrates that greenhouse gas emissions reductions can be consistent with economic prosperity. As we have reduced our emissions towards 1990 levels and put our carbon market into operation, jobs grew by 3.3% – outpacing the rest of the country.[15] Personal income and wages are up – again growing at rates well above the national average.[16] Our electric power grid delivers power reliably, resiliently, and

---

[14] *See* Governor Edmund G. Brown Jr., Executive Order B-30-15 (Apr. 29, 2015), available at: https://www.gov.ca.gov/news.php?id=18938
[15] Environmental Defense Fund, *Carbon Market California* (2014) at 5, available at: http://www.edf.org/sites/default/files/content/carbon-market-california-year_two.pdf.
[16] *Id.*

efficiently thanks to the continued stewardship of our transmission operators.[17] And power bills are down: Californians pay among the lowest power bills in the country – twenty dollars less per month than the national average, and forty dollars less than Texans pay on average.[18]

10. California's experience has not gone unnoticed. Many jurisdictions, international and domestic, are implementing similar programs, and are committing to continue reductions. According to the International Energy Agency, renewable energy will be the single largest source of electricity sector growth over the next five years.[19] By 2020, the IEA expects that the energy coming from renewables worldwide will exceed the energy consumption of China, India, and Brazil combined. California is helping to bring together subnational actors via the "Under 2 MOU" to support this process. To date, 43 jurisdictions in 19 countries and 5 continents have signed. They collectively represent 474 million people, and

---

[17] *See* California Independent System Operator, *What Are We Doing to Green the Grid?* (2014), available at: http://www.caiso.com/informed/Pages/CleanGrid/default.aspx

[18] Energy Information Administration, *2013 Average Monthly Bill – Residential*, http://www.eia.gov/electricity/sales_revenue_price/pdf/table5_a.pdf

[19] IEA, *Renewables to Lead World Power Market Growth to 2020* (2015), available at: http://www.iea.org/newsroomandevents/pressreleases/2015/october/renewables-to-lead-world-power-market-growth-to-2020.html

a GDP of $13.6 trillion – the equivalent of the second largest economy in the world.[20]

11. Although California's emission reductions, and these international efforts, are an important contribution, they alone are not sufficient to fully address global climate change. Doing so requires national and international action. It is clear that United States leadership on this issue is critical, both because national emissions reductions in the United States as a whole can be very substantial, and because United States leadership on this issue will support international climate action.

12. The Clean Power Plan is a critically important part of this necessary national effort. It addresses the largest national stationary source of greenhouse gas emissions, electricity generation, and, according to U.S. EPA's estimates, will generate 32% reductions in emissions from that sector relative to a 2005 baseline. The Clean Power Plan thus makes a very meaningful contribution to reducing United States emissions, and demonstrates the sort of leadership needed to secure further reductions internationally. Benefits from the Clean Power Plan are very significant in all of these regards; indeed, U.S. EPA estimates that the monetized net climate and public health benefits of the plan itself (leaving aside its

[20] *See* http://under2mou.org/?page_id=238.

contribution to international pollution reductions) will be as much as $45 billion by 2030.

13. The Clean Power Plan will also help support and reinforce necessary efforts to reduce other pollutants, including ozone and particulate matter (in lay terms, “smog” and “soot” – both very dangerous to human health). California has significant air pollution challenges that can only be fully addressed by greatly reducing fossil-fuel emissions from all sources, including from power plants. The Clean Power Plan reinforces progress needed to support these reductions in-state and across the country.

14. Securing the full benefits of the Clean Power Plan for California, the country, and the world in the most effective way requires planning for compliance. Any disruptions to the Clean Power Plan have the potential to make it more difficult to achieve cost-effective emissions reductions based upon well-developed plans, resulting in intensified climate change risks, as well as challenges integrating federal programs like the Clean Power Plan with existing state programs.

15. For these reasons, and those discussed more fully below, California would be harmed by any judicial decision delaying Clean Power Plan implementation or decreasing the rigor of the Clean Power Plan.

II. Consistency of the Clean Power Plan's Requirements with Past Planning Efforts

16. One of the significant strengths of the Clean Power Plan is that it relies on the Clean Air Act's successful state/federal planning model, which has helped California and states across the country reduce air pollution for more than forty years. Based on my experience developing California's State Implementation Plans under the Clean Air Act, and on my current responsibilities, I conclude that the Clean Power Plan compliance process is fundamentally similar to the Clean Air Act planning processes that all states have long undertaken, and thus imposes no unique or special burdens on those states that wish to submit their own plans. Instead, it uses highly similar procedures to those that the states successfully employ as a matter of course.

17. Specifically, section 111(d) planning, as envisioned by the Clean Power Plan, is very similar to the planning processes states regularly undertake under Section 110 of the Clean Air Act to meet federal ambient air quality standards for criteria pollutants. That cooperative federalism approach, now in use in the Clean Power Plan, has allowed states to achieve large air pollution reductions while tailoring programs to meet their particular circumstances.

18. Nationally, Section 110 plans (also called State Implementation Plans) and other Clean Air Act programs have reduced aggregate national emissions of criteria pollutants by 72% from 1970 to 2012; during the same period, GDP grew by 219%.[21] This progress has saved, and will continue to save, hundreds of thousands of lives.[22] U.S. EPA reports that monetizing this progress demonstrates $2 trillion of benefits, which exceed costs by a ratio of 30-to-1.[23]

19. Progress in California has also been dramatic. While California's population has increased by 29% since 1990, state and federal clean air planning led to reductions in emissions of ozone-forming pollutant emissions of 50% and toxic pollutants of 80% in that same period.[24] Almost two-thirds of Californians now reside in areas that meet federal ozone smog standards, up from only 24% in 1990.[25]

20. To make this progress, California, like other states, has developed considerable administrative expertise in air pollution control planning. State and

---

[21] *See* U.S. EPA, *Progress Cleaning the Air and Improving People's Health* (2013), available at: http://www2.epa.gov/clean-air-act-overview/progress-cleaning-air-and-improving-peoples-health
[22] *See id.*
[23] *See id.*
[24] *See* California Air Pollution Control Officers' Association (CAPCOA), *California's Progress Towards Clean Air* (2015), available at: http://www.capcoa.org/wp-content/uploads/2015/04/2015%20PTCA%20CAPCOA%20Report%20-%20FINAL.pdf
[25] *See id.*

local clean air agencies employ expert staffs to develop and implement state plans, and planning is an ongoing and regular part of our duties. California state and local agencies, for instance, have developed nearly fifty Clean Air Act implementation plans under Section 110 of the Clean Air Act since the year 2000 alone. California has also successfully implemented U.S. EPA's past section 111(d) emissions guidelines.

21. For instance, California's efforts to meet section 110 standards for particulate matter (PM 2.5) that poses serious health risks to the "South Coast" region – Los Angeles and environs – demonstrates how state planners regularly address potentially complex clean air planning challenges. U.S. EPA set air quality standards for this pollutant for the first time in 1997; addressing these standards was challenging because particulate matter is created by many pollution sources, and the pollutant itself is made up of many different compounds. The South Coast region was designated as out of attainment with those standards in 2005, starting a three-year clock for plan development. South Coast regional officials and ARB worked with U.S. EPA, and successfully developed a plan for these new standards within only two years. The plan contains an extensive and carefully modeled set of measures, regulatory initiatives, and modeling demonstrations intended to demonstrate attainment, and was developed with extensive stakeholder input. The plan was submitted in 2007. This past year, U.S.

EPA, recognizing the progress made, proposed to find that the South Coast region is now in attainment with the standards.[26] This sort of progress is not unusual: California, like other states, regularly implements comprehensive air pollution plans, and has seen significant pollution decreases as a result.

22. I have reviewed the state planning requirements of the Clean Power Plan. For states that choose to develop their own state plans (which are not required), the Clean Power Plan's requirements are no more demanding than those which the states have already met in previous Section 110 and Section 111(d) plans. Both processes require careful analysis of pollution sources and the effects of proposed regulatory regimes on those sources, and careful modeling to demonstrate emissions trajectories. Thus, the task of plan development under Section 111 will be familiar to agencies experienced in Section 110 planning.

23. In some ways, in fact, section 111 plans are somewhat more straightforward substantively. Notably, section 110 plans, which are focused on attaining ambient air quality levels for particular pollutants typically involve measures that affect many source categories – both stationary and mobile – as well as atmospheric modeling to understand the effect of sources on pollutant levels in the atmosphere. Hence, considerable effort is needed to consider measures and impacts across economic sectors. Section 111 planning, by contrast, focuses on

[26] *See* 70 Fed. Reg. 72,999, 73,000 (Dec. 9, 2014) (describing this procedural history and proposing attainment designation).

pollutants from a single source category, and does not require atmospheric modeling.

24. Further, in some regards, the Clean Power Plan also affords states very significant procedural flexibility as they develop their plans that is not always available in the Section 110 process. For instance, California, along with many other states, urged U.S. EPA to offer a wide range of state plan designs, including "state measures" plans that avoid rendering many state programs directly federally enforceable. U.S. EPA granted this request, providing state planners with a very wide range of designs, including the "state measures" option. This state measures option largely allows states to use new or existing programs and policies which are projected to achieve federally required emissions levels without subjecting those policies to federal enforcement – an important source of flexibility that could allow the use of a wide range of policies to respond to the Clean Power Plan at state discretion, including successful energy efficiency policies. Further enhancing state options, U.S. EPA has also proposed model plans and federal plans that states may use as models, or accept as alternatives.

25. Plan submission and implementation timelines under the Clean Power Plan also afford states more than ample time. U.S. EPA requires only a basic initial submission in 2016 to secure an extension for plan submittal to 2018, if necessary. U.S. EPA has also proposed a range of additional submission options –

including partial, conditional, and parallel processing and approval options – that will further accommodate state planners and their schedules. The fact that plans need not begin to meet compliance period requirements until 2022 further provides administrative flexibility.

26. The full seven years between finalization of the Clean Power Plan and the initial compliance period, the fact that emissions reductions then phase in through to 2030, and the up-to three years allowed for plan submissions, with revisions possible thereafter, provides ample time for ARB to enact and implement an appropriate plan. In contrast, ARB has implemented many highly complex state programs that are more sweeping than the Clean Power Plan in significantly less time. For example, California's economy-wide Cap-and-Trade Regulation, which encompasses all large greenhouse gas emitters in the state, took approximately three years to develop and move into implementation from the time the state determined to move forward with the program in ARB's first climate change Scoping Plan.

27. California's experience is not unique in this regard. In my view, the decades of experience which states have accrued in successfully developing and implementing Clean Air Act compliance plans, the wide array of possible plan designs, and the extended implementation and compliance timelines of the Clean Power Plan all render compliance planning entirely manageable for the Air

Resources Board, as well as for other states that wish to submit their own plans. Experience with the Clean Air Act to date strongly suggests that state plans of this sort will be effective and can be implemented smoothly, just as has generally been true for pollution control planning under the Act.

III. Benefits to California of Uninterrupted Implementation of the Clean Power Plan

28. California is moving ahead to implement the Clean Power Plan in accordance with other planning activities for the post-2020 period. I believe that expeditious, integrated planning in California, and across the country, provides significant benefits.

29. Our planning activities include a “scoping plan” establishing California’s overall plans for economy-wide greenhouse gas emissions reductions out to 2030, and amendments to our Cap-and-Trade Regulation, which structures California’s greenhouse gas emissions trading market. That market has operating since 2012, and the greenhouse gas emissions compliance instruments traded in the market reflect billions of dollars in value. The market is used to guarantee emissions reductions throughout the state by requiring participants to meet a declining cap on total emissions, under which trading may occur to allow for more economically

efficient compliance. The power plants affected by the Clean Power Plan generally are also covered by our Cap-and-Trade Regulation, and participate in the market.

30. ARB is beginning the planning process to ready the Cap-and-Trade Regulation for the post-2020 period. Providing a clear path forward to market participants is important to provide certainty to market participants, maintain the value of the market for participants, and ensure that the program continues to operate smoothly to produce emissions reductions. The planning process began with a workshop in October 2015, and is expected to unfold throughout 2016, with a final scoping plan and amendments to the Cap-and-Trade Regulation expected to be considered for approval in late 2016 and early 2017, respectively.

31. ARB is integrating its Clean Power Plan compliance planning efforts with our state-level scoping plan and Cap-and-Trade amendments because all of these processes bear on the obligations of affected power plants now participating in the California greenhouse gas emissions trading market. ARB is making significant efforts to ensure that the compliance obligations created by the Clean Power Plan can be smoothly integrated into the state market program. U.S. EPA has provided ample flexibilities in the Clean Power Plan to support this effort.

32. In order to develop a unified post-2020 regulatory plan for the power sector that will also provide market certainty, it is important that the state and federal planning processes move forward together, allowing carbon and power

market participants to fully understand their obligations going forward. A delayed Clean Power Plan compliance process, on the other hand, could create uncertainty in the market, diminishing market efficiency, and could force California to revisit the state-level rulemakings that will move forward from 2015 to 2017, at considerable administrative cost and inconvenience for all parties. For instance, a stay could push Clean Power Plan compliance planning beyond the planning period for the state-level rulemakings – such as by delaying U.S. EPA's ability to reach a decision on California's compliance plan, and by creating regulatory uncertainty around the process of plan development. The result would be that ARB would have to consider moving forward with state regulatory development, but without fully integrating Clean Power Plan compliance and without the benefit of U.S. EPA regulatory decisions on ARB's determinations for a portion of that period. If a stay generated delays beyond the timeline of the state regulatory process, ARB would likely have to reopen closed state regulatory and planning processes to incorporate the delayed federal requirements, and do so very close to the beginning of the post-2020 period. The resulting administrative and market disruption costs have the potential to be significant. Compliance instruments traded in the California market are cumulatively worth billions of dollars, and the market itself contributes to controlling millions of tons of greenhouse gases, meaning that even small disruptions to the smooth functioning of the market can have large absolute consequences.

33. Our climate planning process also involves substantial efforts to consult with disadvantaged communities. This consultation, including through a formal Environmental Justice Advisory Committee, is focusing on many aspects of ARB's programs, including our post-2020 programs. Here, too, providing stakeholders a comprehensive planning process aids in ensuring a thorough and effective consultation to help address these communities' concerns.

34. This coordination process also involves jurisdictions whose own carbon market programs are linked (in the sense of sharing fungible compliance instruments within coordinated policy designs) to the California market. California's carbon market is currently connected in this way to that of the Canadian Province of Quebec, and other jurisdictions are also exploring linkage. Because the Clean Power Plan compliance process is likely to affect the design of our carbon market, plan development will need to address this linkage as well. For this reason, a unified planning process – that can incorporate linkage considerations – is of considerable importance to avoiding market disruption in other jurisdictions as well and to securing cost-effective greenhouse gas reductions through this growing international effort.

35. Further, the Clean Power Plan compliance strategy for California is being developed at approximately the same time as major planning efforts that will affect our electricity system. One of the state's major electricity grid operators, the California Independent System Operator, will be involved in exploring expanding its power market to embrace power markets in other western states (including Oregon, Utah, and Wyoming) over the 2015-17 period. At the same time, our Public Utilities Commission and Energy Commission will be considering how to implement a new 50% renewable procurement target and other utility planning mandates for the 2020-2030 period. The electricity market shifts required for these programs have the potential to affect power plants regulated under the Clean Power Plan. Accordingly, it is most efficient to develop our compliance strategy in coordination with these electricity system policy efforts; such an effort will best support cost-effective electricity planning, and will also support sensible planning for electrical reliability as these policies are implemented. Again, delaying the Clean Power Plan compliance planning process will make it more difficult to ensure that the power market changes and greenhouse gas emission reduction strategies can relate successfully to each other.

36. Finally, I note that California's successful carbon reduction efforts have been influential in international climate discussions, including both policy efforts amongst subnational entities and in the discussions around the pending Paris

climate negotiations facilitated by the United Nations. Continued successful operation of the California programs, as examples of successful reduction efforts, and as venues to explore policy approaches, is likely to help support efforts worldwide to build upon our efforts. Moreover, international climate negotiations have been strongly influenced towards delivering the pollution reductions necessary by demonstrations that the United States, and individual states, are committed to greenhouse gas emission reduction programs. Accordingly, continued implementation of both our programs and the Clean Power Plan itself, which both help to foster continued international pollution reductions. Delays to implementation may disrupt these international efforts, which are necessary to climate stabilization.

37. Accordingly, California benefits substantially from being able to include Clean Power Plan compliance with its overall planning effort, and can only do so effectively if the Clean Power Plan is not stayed.

38. These potential harms are not likely to be limited to California. Many states are now developing greenhouse gas reduction programs at the state level. These states, too, will benefit from being able to incorporate federal compliance planning into their efforts.

39. California will also experience benefits from expeditious, effective Clean Power Plan compliance efforts nationwide. These benefits include durable state

emission reductions plans, further limiting greenhouse gas emissions endangering Californians. Earlier planning and implementation efforts are also likely to provide opportunities for regional coordination of planning efforts, which could help enhance reductions or reduce costs. Because coordination between state governments takes time, a planning window not shortened by a stay is likely to encourage states to explore and capture these potential benefits.

IV. Harms to California Resulting from a Stay

40. If the Clean Power Plan is stayed, California will experience several serious, and irreparable, harms.

41. First, as I have discussed above, it will be difficult and perhaps impossible to seamlessly coordinate state and federal planning for the post-2020 period in California if the Clean Power Plan is stayed. State-level planning must continue in 2016, but, if a stay is granted, these plans may need to be reopened or adjusted once full federal compliance planning can begin. Moreover, holding the federal compliance planning process so close to 2020, the beginning of the next compliance phase within the state greenhouse gas emissions trading market, will introduce unnecessary market uncertainty, and so may impair the program. The resulting market uncertainty, procedural complexity, and administrative costs

would cause significant harm to California's efforts to develop a unified and effective compliance program.

42. Moreover, staying the Clean Power Plan, or otherwise weakening it, will make it more difficult for state planners to develop durable plans that will deliver the requisite greenhouse gas emissions reductions. During the pendency of a stay, the uncertainty created, along with potential limits on U.S. EPA's implementation abilities, will make it more difficult to move state plans forward with full federal and state involvement in the process. Delays could also create a less certain planning timeline, making it more difficult to coordinate with other state processes. Because thoughtful coordination of this sort is important to effective planning, a stay would make it more difficult to integrate Clean Power Plan requirements into ongoing state processes.

43. Further, any delay to the Clean Power Plan will likely make it more difficult for California and the United States to encourage greenhouse gas reductions from other countries.

44. Critically, if a stay results in further delays to compliance deadlines for the CPP, or to state-level efforts to reduce greenhouse gas emissions, these emissions will likely accumulate in larger quantities in the atmosphere, resulting in increased climate risk to Californians.

45. The net result is that a stay to the plan will impair greenhouse gas reduction efforts at the state, national, and international levels, create uncertainties in California's functioning emissions market, potentially delay compliance deadlines resulting in extended periods of elevated greenhouse gas emissions exacerbating climate risk to California, and impose unnecessary additional planning and process coordination costs on California and similarly situated states.

I declare under penalty of perjury that the foregoing is true and correct. Executed on December 4, 2015.

/s/ Edith Chang
Edith Chang, Deputy Executive Officer

California Air Resources Board

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

STATE OF NORTH DAKOTA

Petitioner,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,

Respondent.

DECLARATION OF RANDEL D. CHRISTMANN

Case No. 15-1380

I, Randel D. Christmann, state and declare as follows:

1. My name is Randel D. Christmann. I am over 21 years of age and am fully competent and duly authorized to make this Declaration. The facts contained in this Declaration are based on my personal knowledge and are true and correct.

2. I am an elected Commissioner on the North Dakota Public Service Commission ("Commission"). I have held my office as a Commissioner since January 1, 2013.

3. The Commission is a state agency established by the North Dakota Constitution. N.D. Const. Art. 5, § 2. The authority of the Commission is set forth in the North Dakota Century Code. Ch. 49-01 et seq., Titles 60 and 64 and Chapters 24-01, 24-09, 38-14.1, 38-14.2, 38-18, and 51-05.1. The Commission has general jurisdiction over "[e]lectric utilities engaged in the generation and

distribution of light, heat, or power." § 49-02-01. The Commission supervises public utilities with the power to "originate, establish, modify, adjust, promulgate, and enforce tariffs, rates, joint rates, and charges of all public utilities." § 49-02-03. The Commission shall determine the value of property of every public utility "for the purpose of ascertaining just and reasonable rates and charges of public utilities." § 49-06-01. The Commission "may approve, reject, or modify a tariff filed under section 49-05-06, which provides for an adjustment of rates to recover jurisdictional capital costs and associated operating expenses incurred by a public utility to comply with federal environmental mandates on existing electricity generating stations," including the federal Clean Air Act (CAA). § 49-05-04.2.

4. The Commission has a statutory duty to ensure that North Dakotans receive a reliable supply of electricity at just and reasonable rates. Additionally, the Commission is responsible for determining whether to authorize generation and transmission infrastructure in North Dakota that is needed by jurisdictional utilities to provide reliable electric service to customers and is otherwise consistent with North Dakota law. North Dakota Century Code Chapter 49-03.

5. In my current position, I am familiar with the Final Rule promulgated by the U.S. Environmental Protection Agency ("EPA") ("Final Rule") entitled Carbon Pollution Emission Guidelines for Existing Stationery Sources: Electric Utility Generating Units. 80 Fed. Reg. 64662 (October 23, 2015).

6. This Declaration has been reviewed by the other two members of the North Dakota Public Service Commission, Commission Chairman Julie Fedorchak and Commissioner Brian Kalk. The Commission held a public meeting on October 23, 2015 and voted to unanimously endorse the content and filing of this Declaration as the official position of the North Dakota Public Service Commission.

7. EPA's requirements in the Final Rule for North Dakota, which are second only to Montana in stringency on a percentage basis, require a 45% reduction in North Dakota's statewide average carbon dioxide (CO_2) emission rate by 2030. However, interim steps have been established by EPA in the Final Rule that require a rate of 1,671 lb/MWh for the 2022-2024 time period, 1,500 lb/MWh for the 2025-2027 period and 1,380 lb/MWh for the 2028-2029 period.

8. EPA's Final Rule requires an emission rate of 1,305 lb/MWh, which is 45% below North Dakota's 2012 baseline emission rate of 2,368 lb/MWh. The Final Rule provides North Dakota with an alternative to EPA's emission rate approach, where EPA prescribes a mass emissions limit of 20,883,232 tons may be implemented. EPA's mass emissions compliance alternative requires a 37% reduction from the 2012 baseline of 33,370,886 tons.

9. EPA's Final Rule requires North Dakota to address not only the emitting sources (coal-fueled power plants) but also extends beyond the boundary

of a stationary source and incorporates non-emitting sources (e.g. wind and solar generation) and redispatching power to lower emitting units. EPA's Final Rule also requires North Dakota to take into account reliability of the electrical system when developing North Dakota's plans, which has never occurred with any other air pollution control rule. The redispatch of power, protecting the reliability of the electrical system, and accounting for wind or solar generation have never before been federal compliance requirements when implementing an EPA rule.

10. Under the Final Rule, North Dakota must choose between two plan types—rate-based or mass-based, to satisfy EPA's aggressive emission targets. In a rate-based State Plan, North Dakota must require affected power plants to satisfy an average amount of carbon dioxide emissions per unit of power produced. The required target would be impossible for any existing North Dakota coal-fired power plant to meet and continue operating, unless that plant purchased emission credits from its "clean" competitors or greatly reduced its coal generation and replaced it with new renewable generation. In a mass-based State Plan, North Dakota must cap the amount of carbon dioxide emissions that the whole sector of affected power plants can emit per year. This type of Plan must include an enforceable emission limitation on power plants and may include additional policy programs, such as increasing renewable energy, tightening energy efficiency standards, and emissions trading.

11. At its core, the Final Rule represents a complex effort aimed at forcing North Dakota (and the Commission) to engage in a significant shift in North Dakota's electrical generating capacity away from carbon-intensive electric generating units to less carbon-intensive sources and zero-carbon generation. Such an extreme mandate adversely impacts North Dakota citizens, businesses and government. It also threatens North Dakota's ability to continue to use lignite and other coals as a low cost electricity generation option, as a means to enable responsible development of the Bakken oil reserves that are critical to North Dakota's continued economic development, and as a necessary part of processing rather than flaring associated natural gas.

12. As part of EPA's rule development process, EPA evaluated the effects of the Final Rule using its Integrated Planning Model (IPM). In this analysis, EPA projected that six units of coal-fired generation (totaling more than 1,300 MW) in North Dakota would retire by 2020. This included the two units of the R.M. Heskett Station, M.R. Young Station Unit 1, Coyote Station, Spiritwood Station and one unit of the Coal Creek Station. In 2014, these units produced 9,672,068 megawatt-hours of electricity or 27% of the total generation in North Dakota. The units consumed nearly 8 million tons of lignite in 2014. This included 2.77 million tons from the Beulah Mine, 1.55 million tons from the Center Mine and 3.53 million tons from the Falkirk Mine. Based on EPA's scenario, the Beulah Mine

would shut down and production from the Center Mine would be reduced by approximately 40%. Production at the Falkirk Mine would be reduced by approximately 50%.

13. Although EPA indicates this is just one possible approach North Dakota may take to comply with the Final Rule, it is unfortunately a realistic scenario given the compliance requirements imposed on North Dakota by the Final Rule. Because North Dakota must reduce its emission rate by 45%, approximately each megawatt hour of North Dakota-based coal generation must be matched with a megawatt hour of zero carbon emitting generation in order to achieve compliance with the Final Rule. Energy efficiency improvements at North Dakota power plants are expected to only produce a 1%-2% increase in efficiency. Since there are no demand side energy efficiency programs (formerly Building Block 4) in North Dakota, the benefit from demand side energy efficiency is likely minimal.

14. Compliance with the Final Rule in North Dakota can only be accomplished by retiring coal plants, greatly curtailing their operations, adding prohibitively large amounts of renewable generation, or purchasing emission rate credits (ERC) or allowances. As such, North Dakota (and thus the Commission) has little actual flexibility to perform its statutory role. If coal generation is not curtailed in North Dakota, the affected utilities will have to purchase ERCs or mass allowances. At this time, the number of ERCs or allowances available is unknown

because the trading program has not been developed. This also makes the cost of the ERCs and allowances unknown. EPA has estimated the cost of compliance at $30 per ton. The cost to North Dakota utilities (ultimately North Dakota and other ratepayers) for the purchase of ERCs could be nearly $375 million per year. With an expanding economy and a large load growth predicted for western North Dakota because of oil and gas development, this makes planning extremely difficult and pushes utilities toward coal-fired plant closures. If plant closures occur, there is insufficient time to plan, design and construct new generation and transmission systems before the initial compliance date of 2022.

15. The shutdown or curtailment of coal-fired generation stations in North Dakota, the possible addition of 4,000-6,000 MW of wind generation, and the addition of backup generation for the wind generation will require a major redesign of the electrical generation and transmission system in North Dakota by 2018.

16. Absent a stay, the Final Rule will force North Dakota to make massive expenditures of time and resources designing State Plans. To participate in the design of any North Dakota plan, the Commission will need to conduct detailed interagency analyses and then consult with various stakeholders to determine what changes can plausibly be made to increase natural gas and renewable energy generation. This process will include an assessment of the forms of energy available to North Dakota, whether developing more new energy sources

is feasible, and what changes to North Dakota law would be required. In addition, because EPA's obligations in the Final Rule can be met through cooperative interstate regimes, North Dakota will need to engage in interstate consultation, determine the possible arrangements, and assess whether such arrangements are desirable to North Dakota.

17. Such Commission efforts associated with implementing EPA's requirements in the Final Rule represents an unprecedented preemption of the sovereign authority and discretion held by the Commission. *See* ¶¶ 4-5, above.

18. The Commission expects development of any North Dakota Plan will require multiple Commission staff employees for the three years from September 2015 to September 2018. The Plan development effort is expected to require the Commission to likely expend several million dollars from its existing budget resources for the current biennium. North Dakota's Legislature meets every two years and concluded its last session earlier this year. EPA's Final Rule was made public and signed after the end of the North Dakota 2015 legislative session. The legislature was not aware of these expenses and did not budget for them with respect to the Commission.

19. The Commission's substantial expenditure of human and fiscal resources associated with implementing the Final Rule will immediately distract

the Commission from serving its full regulatory mission, as directed by the North Dakota Legislature, causing further irreparable harm to the state and its citizens.

20. The Final Rule imposes a four-fold increase in EPA-mandated emission reduction requirements over EPA's proposed rule for North Dakota. The increased burden on North Dakota is larger than for any other state. North Dakota's goal in the proposed rule was 1,783 lb/megawatt-hour which required a 24.7% reduction from the 2012 baseline emission rate. The proposed rule allowed existing wind generation to be counted towards compliance, effectively making North Dakota's reduction requirement 10.7%. The Final Rule established a goal of 1,305 lb/megawatt-hour and does not allow existing wind energy to be counted towards compliance. The Final Rule requires North Dakota to reduce its carbon dioxide emission rate by 44.9% or 420% more than the proposed rule.

21. The Federal Power Act gives North Dakota exclusive authority to regulate our retail electricity market. In North Dakota, the Commission works with investor-owned utilities to determine the appropriate generation mix to meet forecasted load at the lowest reasonable cost. This ensures customers receive a reliable supply of electricity at just and reasonable rates. The Rule invades this authority and preempts the state from implementing its own renewable energy goals, and from maintaining sound management and cost control. Utilities are multi-jurisdictional organizations, susceptible to influences in each of their

operating areas. Utilities may choose the path of least resistance to appease the EPA and outside interest groups as long as they are assured full cost recovery. The "regulatory compact" is a long-standing principle that grants monopoly service to bring efficiency to capital intensive industries. However, this principle also requires clear regulatory oversight in place of competition to protect customers. The Commission ensures that utility companies do not necessarily take the easiest path at the expense of North Dakota Ratepayers. The Final Rule Plan strips the Commission of authority to do so.

22. The Final Rule raises significant electric reliability concerns. Seventy-eight percent of electricity sold in North Dakota comes from coal-fired generation facilities. We have very limited other baseload generation in the state. None of these facilities are currently scheduled for retirement, customers are still paying for them, and utilities have not begun the lengthy planning process involved with replacing these massive baseload power resources. More importantly, the impacts of retirements on reliability have not been modeled. The Final Rule places North Dakota in an untenable position to reengineer the state's electrical system and account for impacts on the power grid's reliability in a timeframe that is arbitrary and untested.

23. The Final Rule threatens to substantially raise rates in North Dakota. Although North Dakota has traditionally benefitted from low-cost electricity, the

Final Rule will cause significant rate increases. The cost to continue operating North Dakota plants at their current capacity would be $375 million annually based on the $30/ton cost used by the EPA. As an example, in a rate-based calculation, North Dakota would need to retire 770 megawatts of coal and replace it with 4,000-5,000 more megawatts of wind in order to meet our goal. This costs an estimated $1.5-2.0 million per megawatt based on the cost of recent wind farm projects in North Dakota. In addition to new investment, North Dakota residents and businesses will be responsible for paying remaining costs for useful existing facilities forced to retire prematurely. The costs of the infrastructure needed to serve new generation including transmission lines and pipelines to fuel combined-cycle power plants, all of which are passed along to customers, have not been included in cost estimates.

24. The Final Rule contains numerous significant, material elements of central relevance to the outcome of the Final Rule that EPA did not identify in the Proposed Rule. As such, the Commission, State of North Dakota and the public were not provided with any opportunity to comment on these new and wholly unexpected provisions. The Commission did not (and could not have) reasonably anticipated these changes. Below is a list of some aspects of the Final Rule for which EPA did not properly give notice in the proposal:

(a) EPA issued voluminous highly technical data and support documents essential to a thorough evaluation of the Proposed Rule as late as

October and November 2014, just days before EPA's close of the public comment period. These documents covered fundamental aspects of the Proposed Rule, ranging from building block methodology, the calculation of state-specific goals, emission reduction compliance trajectories, and the translation of emission rate-based goals to mass-based equivalents. This left insufficient time for North Dakota and the Commission to meaningfully study, evaluate, and comment on the Proposed Rule.

(b) EPA failed to identify in the Proposed Rule all of the potential changes it intended to make to allowances and compliance credits and its intention to undermine existing state Renewable Portfolio Standards programs with its ill-defined Emission Reduction Credit (ERC) program and the mass-based and rate-based trading programs. EPA's decision to include in the Final Rule provisions that disallow credit for a significant portion of North Dakota's existing renewable energy is not a logical outgrowth of the Proposed Rule and could not be anticipated.

(c) EPA did not identify in the Proposed Rule that renewable energy facilities constructed before 2013 would not receive compliance credits during compliance years. Nor did EPA identify that those facilities constructed before 2018 would be denied extra compliance credit from 2020-2021 under the Clean Energy Incentive Program (CEIP) because the CEIP does not credit any facilities built before the final State Plan submittal, which is due on or about September 6, 2018.

(d) EPA revised its "Building Blocks" methodology without giving the public an opportunity to comment on the material changes. The Rule's Building Blocks are the foundation of the performance standards, yet North Dakota did not have an opportunity to comment on the new assumptions for heat-rate improvements for coal plants, dispatch rates for natural gas plants, and expansion of renewable generation.

(e) The final rule provides an adjustment to the baseline fossil fuel-fired generation for several states due to high hydroelectric generation in 2012. These states include South Dakota, Minnesota and Montana which all border on North Dakota. In 2012, hydroelectric generation in North Dakota was 128% of normal. However, EPA denied North

Dakota an adjustment to its fossil generation based on arbitrary criteria including 1) generation had to be greater than 10 percent of total generation, 2) there had to be an increase of greater than 5 percent hydro generation relative to the 1990-2012 average generation, and 3) there had to be a greater than 5 percent adjustment to the state's fossil fuel generation (*CO_2 Emission Performance Rate and Goal Computation Technical Support Document for the CPP Final Rule; p.28)*. North Dakota and the Commission had no chance to provide comment on these criteria and the adjustments that were made.

(f) In addition, EPA applied the Building Blocks to affected sources in a new manner. The performance standards in the Final Rule were developed by applying the Building Blocks to three regional interconnection systems. This novel approach was not contemplated by EPA in the proposed rule.

25. The mandates in the Final Rule frustrate the authority of the Commission and constrain its ability to serve the citizens of North Dakota, as required by the North Dakota state statute. Unless a stay is immediately granted, the Final Rule will impose significant and irreparable harm on the State of North Dakota and it citizens through direct and immediate financial means and a loss of sovereign authority – including that held by the Commission pursuant to the North Dakota Constitution, and state and federal laws.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

Executed on October 27, 2015.

Randel D Christmann

Randel D. Christmann
Commissioner
North Dakota Public Service Commission

On this 27th day of October, 2015, before me personally appeared Randel D. Christmann, known to me to be the person described in the within and foregoing instrument and acknowledged to me that he executed the same.

Charlene A Magstadt

Notary Public

(SEAL)

Burleigh County, North Dakota

CHARLENE A MAGSTADT
Notary Public
State of North Dakota
My Commission Expires Jan. 7, 2016

My Commission Expires: Jan. 7, 2016

8148057_2

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

State of West Virginia, et al., Petitioners, **v.** **United States Environmental Protection Agency, et al.,** Respondents.	Case No. 15-1363 (and consolidated cases)

DECLARATION OF STUART CLARK

I, STUART CLARK, hereby declare:

1. I am now and at all times mentioned have been a citizen of the United States and a resident of the state of Washington, over the age of 18 years, competent to make this declaration, and I make this declaration from my own personal knowledge and judgment.

2. I am currently employed by the Washington State Department of Ecology (Ecology) as the manager of the Air Quality Program. As manager of the Air Quality Program, I oversee the work of Ecology's Air Quality Program throughout the state of Washington. I have worked in this position for approximately ten years. I have worked with Ecology on air quality issues for

more than thirty years. Ecology's Air Quality Program is responsible for preserving, protecting and enhancing the air quality of the state for current and future generations.

3. As part of my work as the manager of the Air Quality Program, I have been involved in numerous efforts to regulate air quality in the state of Washington including air quality planning, state implementation planning, greenhouse gas emissions reduction programs, regulating the power sector, and coordinating with air/utility regulators. Following EPA's issuance of its final rules establishing greenhouse gas emission standards for power plants under Sections 111(b) and (d) of the federal Clean Air Act (CAA), I have been overseeing Ecology's efforts to comply with those rules.

4. Greenhouse gas emissions are causing climate change on a global and national scale, and in the Pacific Northwest, including Washington. A recent "State of the Knowledge Report," entitled Climate Change Impacts and Adaptation in Washington State, released in December 2013 by Climate Impacts Group, University of Washington, and reinforced in its 2015 assessment, summarizes and presents existing knowledge about the likely effects of climate change on Washington State and the Pacific Northwest. The report states that significant changes in Earth's climate system and the climate

of the Pacific Northwest, including Washington, are projected for the twenty-first century and beyond as a result of greenhouse gas emissions.

5. The changes in regional climate, water resources, and coastal conditions that have been observed are consistent with trends we would expect to see as a result of human-caused greenhouse gas emissions. Washington and the Pacific Northwest have experienced long-term warming, a lengthening of the frost-free season, and more frequent nighttime heat waves. Sea level is rising along most of Washington's coast, coastal ocean acidity has increased, glacial area and spring snowpack have declined, and peak stream flows in many rivers have shifted earlier.

6. Projected regional warming and sea level rise are expected to bring new conditions to Washington State. By midcentury, Washington is likely to regularly experience average annual temperatures that exceed the warmest conditions observed in the twentieth century. Washington is also expected to experience more heat waves and more severe heavy rainfall events. These and other local changes are expected to result in a wide range of impacts for Washington's communities, economy, and natural systems. These projected changes threaten our water resources, forests, species and ecosystems, oceans and coasts, infrastructure, agriculture, and human health.

7. Current and future choices about greenhouse gas emissions are important because they will have a significant effect on the amount of warming that occurs after about the 2050s. For example, global warming projected for the end of the century ranges from +1.8°F (range: +0.5°F to +3.1°F), if greenhouse gases are aggressively reduced, to +6.7°F (range: +4.7°F to +8.6°F) under a high "business as usual" emissions scenario. In a Washington-specific economic study, potential costs to Washington of not taking action from climate change impacts are projected to reach nearly $10 billion per year by 2020 and $16 billion per year by 2040.

8. The power sector is one of the largest emitters of greenhouse gases in Washington along with transportation emissions and fossil fuel use in the residential, commercial, and industrial sectors. In addition to combating climate change, reductions in greenhouse gas emissions from power plants will also have cobenefits. We would expect to see decreases from natural gas and coal sources in NOx, fine particulates, and SO_2, pollutants that can directly harm public health and the environment. Washington enacted requirements for the state's largest single source of greenhouse gas emissions, the Centralia coal plant, to shut down operations by 2025 with a schedule of

emissions reductions to be met along the way. The shutdown will also result in decreases in NOx, fine particles, mercury and SO_2.

9. Limits on the Boardman power plant in Oregon will not only address that plant's emissions of greenhouse gases but its emissions of nitrates and its visibility impairment of the eastern portion of the Columbia River Gorge National Scenic Area, spanning southern Washington and northern Oregon. As renewable energy sources continue to be utilized and energy efficiency increases under the Clean Power Plan (CPP), fossil fuel sources will be used less thus decreasing greenhouse gases and other pollutants associated with these sources.

10. Many Washington communities, government agencies, and organizations are preparing for the impacts of climate change. Ecology released a state adaptation plan on April 3, 2012, entitled Washington State Integrated Climate Change Response Strategy. Ecology and a number of other state agencies developed the strategy as a framework for decision-makers to help protect Washington's communities, natural resources, and economy from the impacts of climate change. The framework includes ways to protect people and the environment by reducing risk of damage to buildings, transportation systems, and other infrastructure; reducing forest and agriculture vulnerability;

improving water management; safeguarding fish, wildlife, habitat, and ecosystems; reducing risks to the ocean and coastlines; supporting the efforts of local communities; and strengthening capacity to respond and engage the public.

11. Washington has taken numerous steps to mitigate climate change impacts in the last decade. These include enacting statewide greenhouse gas emission reduction limits that require reductions in greenhouse gas emissions over time including reaching 1990 levels by 2020; 25 percent below 1990 levels by 2035; and 50 percent below 1990 levels by 2050, or 70 percent below expected emissions that year.

12. For power plants, Washington has enacted carbon dioxide mitigation requirements, renewable portfolio standards, and greenhouse gas emission performance standards. It enacted legislation for the shutdown of the Centralia coal plant, the state's largest single source of greenhouse gas emissions. It has established requirements for utilities to perform integrated resource planning on a two-year frequency for meeting forecasted annual peak and power demand, with the lowest reasonable cost and risk. Utilities must pursue all available conservation that is cost-effective, reliable, and feasible.

13. Washington has enacted economy-wide greenhouse gas reporting requirements for large emitters including power plants. Ecology has adopted EPA's "Tailoring rule" that establishes greenhouse gas emissions standards for major stationary sources, including power plants that are subject to the federal Prevention of Significant Deterioration Program, to use best available control technology to reduce those emissions. Washington has adopted greenhouse gas emission standards for Washington's existing refineries. Washington has enacted greenhouse gas emission standards for motor vehicles. All of these statutory and regulatory actions have been accomplished while the economy of Washington has continued to grow and energy prices have remained among the lowest in the country. Currently, Ecology is developing a rule setting a declining cap on carbon emissions in Washington to achieve reductions in greenhouse gas emissions from the state's largest emitters of greenhouse gases including power plants. Combined, these policies will go a long way to reducing Washington's statewide greenhouse gas emissions.

14. Washington strongly supports federal greenhouse gas emission standards under the CPP. Federal standards will benefit Washington because they will ensure reductions of greenhouse gas emissions throughout the

country to mitigate harms from climate change and create incentives for development of cleaner sources of power in Washington. To express its support of the CPP rule, Ecology, in partnership with the Washington State Department of Commerce (Commerce) and the Utilities and Transportation Commission (UTC) reviewed and submitted comments on the proposed rule to EPA on December 1, 2014. The State Energy Office at the Department of Commerce (Commerce) is the state executive agency responsible for developing and analyzing state energy policies. The Utilities and Transportation Commission (UTC) is an independent quasi-judicial regulatory body that regulates the rates and services of investor-owned utilities, and ensures reliable and affordable service.

15. Ecology, Commerce, and UTC have reviewed the final rule. EPA's model plans have been helpful to understand the rule's provisions. The three agencies' comments on the proposed CPP suggested that the rule could be improved if EPA used a multi-year average between three to five years to establish the baseline for setting the interim and final state goals because Washington is a hydro-dominant state and 2012 was an uncharacteristically high water year to use as a baseline where little fossil fuel generation occurred. EPA addressed that comment with a three-year average using the

year before and after 2012, for a more representative baseline. The agencies also suggested that EPA allow the states to submit amendments to their plans at any time subject to EPA's approval. EPA responded by defining a process for states to submit amendments. Finally, we suggested that we have flexible interim compliance targets and changes to how the rule would address energy efficiency. EPA responded positively to make appropriate changes that still kept a stringent overall rule but made implementation more flexible and improved the final rule. After its review of the final rule, Washington believes it is well positioned to implement the CPP.

16. Ecology has begun its efforts to develop the plan to comply with the CPP. These efforts include a stakeholder meeting/listening session to get early views from stakeholders on what approaches it should consider and what areas the stakeholders consider important for discussion. Additional stakeholder and public meetings will be held and Ecology will use webinars and other internet-based tools to present options and elicit opinions from the stakeholders. A technical meeting was held in early November to begin addressing key technical issues related to the Northwest's power generation system and the effects various CPP policy choices might have on the power system. Ecology is developing a plan to work with low income and vulnerable

communities on impacts and opportunities resulting from the CPP. These and other appropriate actions will enable Washington to make its initial submittal by September 6, 2016, as required by EPA's final rule. Washington will be ready to submit its final plan on or before September 6, 2018.

17. Ecology, together with Commerce and UTC, has the ability to direct adequate technical resources and staff to analyze the rule and develop the plan to comply with the CPP. Ecology has determined that rulemaking will be required to implement the CPP. The three agencies are using normal funding sources from state appropriations to fund this work.

18. Ecology should have sufficient ongoing resources to develop and submit the state's CPP plan while also continuing to work on state implementation plan update requirements for new National Ambient Air Quality Standards and including updated regulatory text into those plans. It does not expect the need to divert resources from Ecology's other public policy priorities to implement the CPP.

19. The CPP is not expected to interfere with the state's regulation of the power sector that ensures system reliability and just and fair rates for consumers. Various power planning entities have analyzed impacts of shifting to cleaner energy. The Western Electricity Coordinating Council promotes

regional electric service reliability in western Canada and the western United States and performs system-wide modeling for power demand and system reliability. In 2014 the Western Electricity Coordinating Council modeled the consequences of the shutdown of approximately 7000 MW of coal-fired generation in the west and determined no adverse impact on system reliability.

20. The Northwest Power and Conservation Council performs system load modeling for periodic power plans, including modeling for the seventh plan which is currently being developed. Both the sixth and draft seventh power plans show relatively flat load growth in the Northwest and that cost-effective conservation and energy efficiency programs should ensure that the bulk of the power needs are met. The plans show a continued shift away from coal to natural gas, increased energy efficiency, and renewables to comply with state and federal laws and regulations without creating reliability issues or compromising fair rates. Commerce and UTC, working with Ecology, will help to ensure the final Washington plan does not conflict with rate and reliability priorities.

21. Washington's energy conservation efforts and renewable resource requirements in the energy sector affect greenhouse gas emissions. Washington compels utilities to be proactive and forward-thinking with

requirements of ten-year conservation potentials and biennial conservation targets. Utilities also have annual deadlines for reporting their compliance with Washington's conservation and renewable portfolio standards. The investor-owned utility companies regulated by the UTC have been meeting their renewable portfolio standards obligations to provide an increasing percentage of electricity generated from renewable resources, which will increase to 9 percent in 2016 and to 15 percent in 2020.

22. The UTC regulates the recovery of the costs of these conservation and renewable energy efforts by requiring timely reports, evaluating the prudence of the costs incurred, and ensuring that costs included in rates charged to the public are fair, just, reasonable, and sufficient. The strength of its conservation and renewable energy programs highlights a blueprint for Washington to comply with the CPP. While Washington can already be considered a leader in energy conservation and promotion of renewable resources, it welcomes rules that will directly regulate greenhouse gas emissions in the electricity sector and does not anticipate immediate harm or negative consequences from the CPP's planning requirements.

23. The CPP's compliance measures are consistent with market trends affecting the state's electric power sector, and actions taken to comply

with the plan will not require a major reorganization or disruption of the state's energy economy or regulatory programs. For example, renewable portfolio standards have driven the market to develop almost 9 GW of wind generating capacity in the northwestern United States. Washington has a requirement that utilities are to develop all cost-effective energy efficiency measures. Current power market costs and dispatch favor hydropower, wind, and natural gas combined cycle combustion turbines over coal units, especially those coal units owned by independent power producers. The CPP is expected to support the trend to conservation and renewables and to continue to support development of cleaner power that is cost-effective.

24. To assist with the completion of the state implementation plan for the CPP, the state has available data and analyses from existing programs that will inform the state's process. In addition to the data mentioned above, Ecology administers a greenhouse gas reporting program that requires the power sector to report its emissions. Commerce and the UTC have information about power demand, reliability, and cost. Finally, information comes from investor and consumer-owned utilities in Washington that prepare integrated resource plans.

25. Commerce is coordinating a series of meetings with the investor-owned utilities and others concerning power system modeling to further evaluate the utilities' costs to comply and overall system reliability under the CPP.

26. We do not expect implementation of the CPP to interfere with implementation of Washington's other energy policies and priorities. Instead we expect it to complement those other priorities that have the same objectives that the CPP will advance, including the emissions performance standard, renewable portfolio standard, and energy efficiency resource standard. Other federal systems have not negatively affected the delivery of electricity. For example, the creation of Bonneville Power Administration (federal power agency) and the federal hydroelectricity system have provided the region with low power costs that have benefitted utilities and retail electric customers.

27. Ecology has prepared and submitted state planning documents to EPA before under CAA, including state implementation plans. Washington State has been involved in developing and implementing plans to meet the CAA, Section 110 requirements and nonattainment and maintenance plans since the first plans were required in the 1970s. Ecology has developed at least two plans under CAA, Section 111(d). Ecology has adopted and implemented

Section 111 regulations applicable to new sources and those issued under Section 129 for waste incinerators. Throughout those processes, Ecology worked closely with EPA to ensure each plan met all requirements and expectations. Ecology will continue its close cooperation with EPA to implement the CPP, incorporating any feedback and refining submission(s) as necessary.

28. Washington has developed previous CAA implementation plans in significantly less time than the three-plus years the CPP allots for states to develop compliance plans. Based on this experience and Ecology's review of the CPP, Ecology anticipates developing a final plan within the timelines established in the CPP.

29. Ecology does not anticipate that it will need to seek new legislation to comply with the CPP. However, should it need to do so, Ecology has previous experience seeking state legislation necessary to implement federal environmental laws and clean energy policies. In 2012, Ecology successfully obtained legislative authority in the Washington Clean Air Act, Wash. Rev. Code 70.94, to allow it to regulate emissions from woodstoves and wood heating devices in areas threatened to violate or in violation of the federal particulate matter National Ambient Air Quality Standard. The

legislation needed was obtained in one legislative session in less than one year. Ecology has experience adopting rules to implement federal programs including new emission standards for hazardous air pollutants for industrial facilities under Section 112 of the CAA, and new National Ambient Air Quality Standards under Section 110 of the Act. Ecology can rely on this and other rulemaking experience to timely adopt rules necessary to implement the CPP.

30. Ecology routinely coordinates with Commerce and the UTC on issues of shared interest. For example, when the Washington Legislature enacted emission performance standards for electricity generating units, Commerce worked closely with Ecology, and involved UTC as Ecology adopted a rule to implement the standards. Similarly, Commerce worked with Ecology on Ecology's rule that implemented statutory CO_2 mitigation requirements for power plants. Ecology has also worked with Commerce since 2008 to biennially determine the total emissions of greenhouse gases for Washington and to develop an emissions reporting system to allow a comprehensive inventory of emissions of greenhouse gases from all significant sectors of the Washington economy.

31. EPA has made available a draft model federal plan that would satisfy the CPP requirements for state plans. Washington may want to use the model rules as the state plan, as the basis of a state plan, or, under a "state measures" plan, as a backstop plan.

32. The state has repeatedly sought to expedite EPA action to place federal limits on greenhouse gas emissions. Washington was one of a group of states who through litigation succeeded in requiring EPA to adopt greenhouse gas emission standards for motor vehicles, as well as the power plant rules at issue in this case. Washington was one of a group of states that supported EPA in the litigation challenging EPA's "Tailoring rule".

33. Staying the CPP could delay long-overdue reductions in emissions from the nation's power sector, whose emission reductions would help prevent the worst impacts of climate change in Washington. Delays in emission reductions from these sources will cause the emissions to stay in the atmosphere for many years to come and aggravate the climate change harms to Washington. It will also delay the public health and environmental cobenefits of reductions in criteria and hazardous air pollutants.

34. The CPP acknowledges and provides mechanisms to credit the state's past, present, and future investments in renewable energy and energy

efficiency. It will allow Washington to utilize the benefits from emission reductions generated by investments in renewable energy and energy efficiency that occur after 2013.

35. Washington appreciates that the CPP provides incentives for early action, in the form of bonus emission reduction credits or carbon allowances. These can be obtained by implementing renewable energy deployment and low-income energy efficiency programs that provide emission reductions in 2020 and 2021 that are completed by January 2022. The state is considering including these incentives in its compliance plan.

36. A stay of the final rule would create harmful uncertainty about the timeframe for new renewable or energy efficiency projects to qualify for the program's incentives. If the stay were not lifted until after the state plans are due (under the current rule), this could compress project development times and significantly delay projects or limit their ability to qualify for compliance.

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

DATED this 3rd day of December 2015, in Lacey, Washington.

STUART CLARK

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

STATE OF WEST VIRGINIA,
STATE OF TEXAS, *et al.*,

Petitioners,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY,

Respondents.

Case Nos. ________

DECLARATION OF WEST VIRGINIA,
DEPARTMENT OF ENVIRONMENTAL PROTECTION

I, William F. Durham, declare as follows:

1. I am the Director of the Division of Air Quality at the West Virginia Department of Environmental Protection (DEP). I have been employed at the DEP for over 23 years. For the most recent 10 years, I have been responsible, in a supervisory capacity, for the development of state plans and revisions thereto submitted to the U.S. Environmental Protection Agency (EPA) pursuant to the Clean Air Act (CAA) as amended. 42 U.S.C.A §§ 7401 - 7671q. These include

revisions to the State Implementation Plan (SIP) pursuant to CAA §110 and plans, or revisions to plans, pursuant to CAA §111. During my tenure, I have overseen the development of a multitude of state plans which were submitted to EPA for approval, including every SIP revision or state plan West Virginia has produced in the last ten years. Some of the more substantial plans include five (5) EPA-approved ozone maintenance plans for areas previously designated as nonattainment under the ozone National Ambient Air Quality Standard (NAAQS); six (6) EPA-Approved fine particulate maintenance plans under the $PM_{2.5}$ NAAQS; a partially approved Regional Haze plan (the deficiency was outside of the state's control); and a fully approved Regional Haze Five-Year Progress Report SIP. Moreover, under my supervision, nine (9) West Virginia Legislative Rules were developed, adopted by the state and approved by EPA for incorporation into the West Virginia SIP. Finally, I supervised the development of four (4) attainment demonstrations for previous fine particulate nonattainment areas, which included highly technical photochemical atmospheric modeling.

2. With my personal knowledge and experience, I understand the steps that DEP has taken and those it will need to undertake in response to the EPA's Section 111(d) Rule. Based on my experience, I have determined that implementing the Section 111(d) Rule will be an extremely complicated and time-consuming endeavor. It will be the most complicated CAA implementation effort

West Virginia has ever undertaken. The Section 111(d) Rule is unlike any other Clean Air Act implementation undertaken by West Virginia. Specifically, the Section 111(d) Rule's reliance on measures outside the affected facilities' boundaries (fence-line)—building blocks 2, and 3—are entirely unprecedented for any state. West Virginia will be required to expend an unprecedented amount of resources to design a State Plan that incorporates emission rate and/or emissions mass reductions related to these building blocks. It is also apparent that other state entities beyond DEP, including, but not necessarily limited to the West Virginia Division of Energy and Public Service Commission will expend significant resources as well. Because of the unprecedented reach of the 111(d) Rule into areas that neither the CAA nor its state law counterpart in West Virginia have ever been extended, authorizing legislation presenting many issues at the highest level of state policy will require the state Senate, the state House of Delegates and the office of the West Virginia Governor to expend significant resources in developing, and guiding the policy for implementation of the 111(d) Rule.

3. Since the rule was proposed in June of 2014, at least five (5) DEP senior staff employees have expended 2,700 hours or more on understanding the Section 111(d) Rule and preparing for its implementation, including: reading the proposed rules and supporting documentation; drafting comments on the proposal; holding meetings with power plant owners/operators, the Division of Energy, the

Public Service Commission, and PJM, the Regional Transmission Organization that serves West Virginia; and, participating in numerous webinars and conference calls in an effort to understand the options available to the state in order to comply with the rule as proposed.

4. Several constraints combine to force the DEP to put a great deal of its resources into the work of developing a state plan immediately. As suggested above, adoption of legislation authorizing the DEP to expand the scope of its regulatory jurisdiction will be required. After that is accomplished, compliance with legislative rulemaking requirements for adoption of implementing regulations requires nearly a year, beginning in May and extending through legislative approval of rules in March of the following year. Drafting the necessary legislation and rules will be a time consuming endeavor. The State Plan DEP must develop is subject to Legislative approval and the constraints contained in the West Virginia Code. Furthermore, EPA's deadlines in the 111(d) Rule make it nearly impossible for DEP to design a State Plan in time to comply.

5. The stringency of the 111(d) Rule's interim goals exacerbates the pressure on the DEP to immediately dedicate a great deal of resources into development of a State Plan. To comply with the interim goals that purportedly provide a "glidepath" from 2022 to the final goals in 2030, affected power producers must begin their efforts well before the interim goals take effect in 2022.

Any delay in expending resources to develop and submit a state plan to EPA will shorten the amount of time power producers will have to begin their compliance efforts, making them less likely to be able to comply. After a Plan is submitted to EPA, whatever additional time is lost in EPA's approval process will further shorten the time power producers have to try to comply with the interim requirements and make them even less likely to be able to comply with them. Days lost in DEP's development and submission of a State Plan and in EPA's approval of it are days the power industry will not have to devote to compliance efforts.

6. Planning and compliance for the Section 111(d) Rule, including designing a State Plan, will require an unprecedented amount of resources, the expenditure of which has already begun. The Section 111(d) Rule gives West Virginia until September 6, 2016 to submit its initial State Plan. Extensions are available for up to two years for submittal of a final plan. In practice, a state has only one year to make the critical decisions that will dramatically affect its citizens and economy for decades to come, requiring careful consideration of all available approaches. EPA has illustrated at least six basic approaches that a state may adopt. Submission of a plan will require the state to consider these and other approaches and choose an approach within little more than a year, so that a timely plan submittal can be made. In addition to describing the approach the initial plan must also: identify

how it applies to affected EGUs; demonstrate that the plan will meet the applicable rate or mass state goal; define monitoring, reporting and recordkeeping requirements for affected EGUs; specify state recordkeeping and reporting requirements; document public participation and public hearing and include any pertinent documentation. Preparing and submitting a timely plan requires several dedicated DEP staff members, as well as significant resources from other state agencies, stakeholders, and the legislature. Activities include: reviewing the final rule to determine whether the data and underlying assumptions used in calculating the goal are correct; educating the regulated entities and other stakeholders regarding provisions of the final rule; coordinating with the PSC and DOE regarding renewable energy standards, demand side management programs and other issues; evaluating different compliance strategies that could be implemented to meet the interim and final goals; determining the statutory and regulatory changes needed for each of the strategies; and taking initial steps to develop support across all stakeholders and policy makers for potential compliance strategies. Concurrently, the DEP will need to review and comment on EPA's proposed "backstop" Federal Plan (FP) to evaluate the consequences if the state is unable to submit an approvable plan in a timely manner. I estimate that DEP will need to engage nine (9) senior staff employees, providing 7,100 hours of effort or more to address these tasks.

7. EPA has recently issued two “SIP Calls” to West Virginia to correct deficiencies in the extant SIP: *Findings of Failure To Submit a Section 110 State Implementation Plan for Interstate Transport for the 2008 National Ambient Air Quality Standards for Ozone* and *State Implementation Plans: Response to Petition for Rulemaking*, 80 Fed.Reg. 39961 (July 13, 2015), and *State Implementation Plans: Response to Petition for Rulemaking; Restatement and Update of EPA’s SSM Policy Applicable to SIPs; Findings of Substantial Inadequacy; and SIP Calls To Amend Provisions Applying to Excess Emissions During Periods of Startup, Shutdown and Malfunction; Final Rule*, 80 Fed.Reg. 33840 (June 12, 2015). Moreover the state has outstanding obligations to address two nonattainment areas under the sulfur dioxide standard. The enormous resource drain caused by attempting to understand the requirements of a final rule and develop an approvable 111d plan will severely impact the DEP’s ability to fulfill these and other obligations under the CAA.

8. Implementation of the Section 111(d) Rule will require statutory and regulatory changes, all requiring considerable staff time. The Section 111(d) Rule requires a sweeping change to the DEP’s authority. In addition to submitting a compliance plan for EPA approval, DEP must have the ability to enforce each portion of the state plan, many elements of which are beyond DEP’s current authority. In order to have the ability to enforce components of the plan, such as

energy efficiency and redispatch of electricity on the grid, the West Virginia legislature will have to re-write state law. Consultation to ensure that authorities are clearly delineated among agencies will include additional meetings with PSC and DOE staff, owners/operators of power production and PJM.

9. Importantly, the required changes in West Virginia's law will need to be undone if the Section 111(d) Rule is invalidated.

10. The aforementioned reasons demonstrate that a stay of the final Section 111(d) rule is clearly warranted.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct. Executed on this 10th of August 2015, at Charleston, West Virginia.

WILLIAM F. DURHAM

OFFICIAL SEAL
NOTARY PUBLIC
STATE OF WEST VIRGINIA
TAMRA L. MOWRER
WV DIVISION OF AIR QUALITY
601 57th STREET, SE
CHARLESTON, WV 25304
My commission expires January 2, 2018

Tamra L. Mowrer

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

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ________

DECLARATION OF THOMAS W. EASTERLY, COMMISSIONER, INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

I, Thomas W. Easterly, declare as follows:

1. I am the Commissioner of the Indiana Department of Environmental Management (IDEM). I have been the Commissioner of IDEM for over ten years. As the Commissioner, I have personal knowledge and experience to understand what steps IDEM has taken and will need to undertake in response to the Environmental Protection Agency's *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, published on the EPA website on August 3, 2015 (Section 111(d) Rule). EPA-HQ-OAR-2013-0602, available at http://www.epa.gov/airquality/cpp/cpp-final-rule.pdf. The final Section 111(d) Rule sets a deadline of September 6, 2016 for submitting initial plans, with

the final deadline for a complete plan, with all legislative authority required to implement the plan, in place by September 6, 2018.

2. IDEM has determined that implementing the Section 111(d) Rule will be a complex and time-consuming endeavor. Specifically, creating a plan under the Section 111(d) Rule is complicated by the Rule's unprecedented reliance on outside-the-fence control measures, including increased utilization of renewable energy. IDEM has determined it cannot meet the reduction goals set by the Section 111(d) Rule solely through the implementation of heat rate improvements, and thus will be forced to implement unorthodox outside-the-fence control measures in order to have its plan approved. Such measures will require a coordination effort across multiple state agencies, including the Indiana Utility Regulatory Commission (IURC) and the Indiana Utility Forecasting Group (IUFG). Currently, neither IDEM nor any other Indiana state agency has the authority to implement outside-the-fence controls in the measurable and enforceable fashion required by the Clean Air Act. Therefore, in order to comply with the Rule, the State would have to take legislative action to ensure the appropriate state agencies have the authority needed to create and implement any state plan.

3. Indiana's power supply is also governed by more than one Regional Transmission Organization (RTO), requiring coordination with both the Midcontinent Independent System Operator (MISO) and the Pennsylvania Jersey

Maryland Power Pool (PJM), in attempting to find ways to implement the outside-the-fence building block. The coordination among state agencies and RTOs, as well as the legislative changes required to implement the Rule, make creating a state plan extremely difficult, especially in the limited timeframe contemplated by the Section 111(d) Rule.

4. As a practical matter, in light of the September 6, 2016 and September 6, 2018 deadlines, the State cannot wait until the litigation challenging the Rule is concluded to begin evaluating the Section 111(d) Rule and expending substantial resources to create a state plan. The State has already expended resources and expects to take further steps in the coming years as a direct result of the Section 111(d) Rule. This expenditure of resources will likely include coordinating among state agencies and RTOs, seeking input of interested stakeholders, participating in external modeling and cost analyses, and possibly requesting legislative changes to give IDEM or another state agency the authority needed to implement the outside-the-fence building block required by the Rule. Without a stay of the final rule, IDEM cannot wait until litigation is concluded before expending significant time and resources on formulating a state plan and seeking regulatory and legislative authority to implement the plan. However, even if Indiana begins its work immediately, it is unlikely that it can meet the timeframes for reductions set by the Section 111(d) Rule. The deadline for Indiana state agencies to propose legislative

changes to be considered during the 2016 Indiana Legislative Session has passed, so any legislative changes made in response to the 111(d) Rule will not take effect until at least July of 2017. Indiana's statutory rulemaking process then takes at least eighteen months to complete, meaning Indiana will likely not have an approvable plan in place prior to the final September 6, 2018 deadline. From a resource perspective, the Section 111(d) Rule also detracts from efforts to implement other requirements of the Clean Air Act, and provides no additional revenue or resources to the State.

5. Significant changes have been made in the final Section 111(d) Rule from the version that EPA published for public comment on June 18, 2014. 79 Fed. Reg. 34,830. These changes have negated much of the work IDEM has already performed in trying to formulate a plan based on the draft language, and will now require significant analytical work to formulate an approvable plan in the short timeframe set by the September 6, 2016 deadline. Specifically, the final rule includes a substantial increase in the reductions required by Indiana sources. For example, the proposed rule set a emissions rate of 1,531 CO_2 lbs/Net MWh to be achieved by 2030, while the final rule sets a 2030 rate of 1,242 CO_2 lbs/Net MWh. IDEM has already spent time and resources trying to formulate a plan that would achieve the reductions in the proposed rule; Indiana must now perform new calculations and analysis, and has barely a year to perform this work.

6. Another change in the final Section 111(d) Rule is the option to implement an emissions trading program as part of a state plan. Inclusion of a trading program would require significant coordination with other states to ensure enough credits are available for exchange through approved trade-ready plans. Again, this coordination will be difficult, if not impossible, to perform before the September 6, 2016 deadline. Additionally, on the same day that it published the Section 111(d) Rule on its website, EPA issued a proposed rule, *Federal Plan Requirements for Greenhouse Gas Emissions form Electric Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulation.* EPA-HQ-OAR-2015-0119, available at http://www.epa.gov/airquality/cpp/cpp-proposed-federal-plan.pdf. *Inter alia,* the draft rule purports to offer implementation guidance on trade-ready programs. However, the proposed rule is not final yet, and therefore Indiana and other states cannot rely on its guidance in attempting to develop an approvable state plan that includes emissions trading. It is possible the rule providing guidance on trading programs will not be finalized until after the Section 111(d) Rule's September 6, 2016 deadline for submitting plan proposals, further supporting the need for a stay of the Rule's deadlines.

7. The proposed rule mentioned above also includes a draft federal plan for states that are not able, or choose not to, have a state plan approved by EPA. As stated earlier, the draft rule may not be finalized before the September 6, 2016 deadline for submitting plan proposals. Without a stay of the submittal deadlines in the Section 111(d) Rule, Indiana and other states will be forced to make decisions about whether to attempt to formulate a state plan, or choose to be subject to a federal plan, with incomplete information on what the federal plan would entail.

8. In addition, it is uncertain whether any state plan will be approved by EPA in time for utilities to comply with the Section 111(d) Rule's interim goals. As stated above, the reductions required of Indiana sources in the final rule are significantly greater than the proposed rule, largely because the reliance on zero-emitting renewables increased by threefold. The reductions in the final rule are based on a regional flat rate of 20.5% zero-emitting renewables (RE), or more than 22 million MWh. While the final rule does not mandate that RE be utilized to achieve the required reductions, it is highly unlikely that Indiana will be able to develop an approvable plan that does not rely on a considerable growth in zero-emitting renewable energy. Based on the complexities, required coordination and consultation, it would take Indiana all if not more of the three full years to devise a plan, and, based on my experience as Commissioner, EPA is likely to take at least 2 years to act on it. Therefore, at best, an enforceable plan would not be in place

until mid-2020. Utilities, the state utility regulatory agencies, and the RTOs would likely not take action on measures within a state plan until it is federally approved and enforceable. In order for Indiana and its EGU fleet to comply with the rule's 2022 interim goal, all measures would need to be in place by January 1, 2022. Once the state plan is approved, the utilities would have less than two years to secure utility commission approval of cost for infrastructure improvements necessary to achieve the goal and institute the changes needed. For renewables, time is required to secure capital equipment financing, add the infrastructure necessary to get the energy from the equipment to the grid, acquire property and transmission line right-of-way, and finally construct the equipment and required transmission. For both fossil fuel and renewable projects in Indiana over the course of the past 10 years, a minimum of 5-10 years has been required from utility commission approval to when energy is delivered to the grid. Achievement of the Section 111(d) Rule's interim goals is therefore practically infeasible.

9. Undertaking the required measures will seriously disrupt the State's sovereign priorities, which would otherwise be devoted to addressing other pressing issues of public concern. Importantly, the above-described measures would also involve changes in Indiana regulations and statutes, which will then need to be undone if the Section 111(d) Rule is invalidated. Again, this would seriously disrupt the State's ability to achieve its own sovereign priorities.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct. Executed on this 12TH day of August in Indianapolis, Indiana.

Thomas W. Easterly, Commissioner
Indiana Department of Environmental Management

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

STATE OF NORTH DAKOTA

Petitioner,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,

Respondent.

DECLARATION OF LANCE D. GAEBE

Case No. 15-1380

I, Lance D. Gaebe, state and declare as follows:

1. My name is Lance D. Gaebe. I am over 21 years of age and am fully competent and duly authorized to make this Declaration. The facts contained in this Declaration are based on my personal knowledge and are true and correct.

2. I am employed as the Commissioner of University and School Lands and in this capacity oversee the North Dakota Department of Trust Lands ("DTL"). I have been employed by the State of North Dakota since 2000, and have continuously served as the Commissioner of University and School Lands since August 2010.

3. As Commissioner, I direct all responsibilities of the DTL which include overseeing trust assets – including 700,000 surface acres and 1.8 million mineral acres managed to provide revenue to North Dakota's primary schools and other public institutions. Additionally, the DTL administers North Dakota's permanent

educational trust funds and assets under the control of the Board of University and School Lands as set forth in Article IX of the North Dakota Constitution.

4. The surface and mineral acreage in the trust assets include tracts across North Dakota, all acquired through the Enabling Act of 1889 in which the Federal Government granted North Dakota two sections of land in every township, sections 16 and 36, to be held in trust for the "support of the common schools" and public education, Enabling Act of 1889 – 25 U.S. Statutes at Large, c 180 p 676. § 10. This federal grant of land initially totaled more than 2.5 million acres.

5. Under sections 12, 14, 16 and 17 of the Enabling Act of 1889, Congress provided further land grants to the State of North Dakota for the support of colleges, universities, the state capitol and other institutions. These original grants totaled 668,000 acres which established twelve permanent trusts, as identified in the North Dakota Constitution, Article IX sections 12 and 13.

6. Under state law, coal deposits within land managed for the Common Schools Trust Fund and other permanent trusts may be leased for a royalty upon the coal actually produced. North Dakota Constitution, Article IX Sections 5, 6, & 8 and North Dakota Century Code Chapter 15-05. Included within my official responsibilities is management of 8,447 acres currently leased for the production of lignite coal. These leases contain provisions for payment to the trusts of a one-time

bonus; an annual per acre rent payment; and a royalty payment per ton of coal produced.

7. The royalty rate in the longstanding leases is $0.85 to $0.88 per ton of coal currently being produced. Existing leases for future lignite production include a royalty ranging from $0.29 to $.035 per ton for coal produced, some with a 3% annual escalator.

8. I am responsible for the collection of rents and royalties from coal production on:

a. 1,342 acres leased to BNI which provides coal from the Center Mine to the Milton R. Young Station;

b. 6,066 acres leased to North American Coal Royalty Company including:

   i. 1,778 acres in the Falkirk Mine, which produces lignite for Great River Energy's Coal Creek Station and the Spiritwood Station;

   ii. 1,776 acres in the Freedom Mine, which supplies lignite to Basin Electric Cooperative's Antelope Valley Station, the Dakota Gasification Company, and the Leland Olds Station

   iii. 1,880 acres within the Coyote Creek Mine, which will soon deliver coal to the Coyote Station,

iv. 632 acres with the Otter Creek Mining Company anticipated to produce soon; and

c. 1,039 acres leased to Dakota Westmoreland which operates the Beulah Mine, which currently serves the Coyote Station as well as the R.M. Heskett Plant.

9. As of October 16, $ 2,066,309 of royalty and rental revenue from the production of coal was collected in calendar year 2015 for the benefit of the Common Schools Trust Fund and other permanent funds which support North Dakota institutions. In 2013 the trust funds received $3,758,522 of royalty and rental income; and in 2014, $3,787,924 of royalty and rental revenue and an additional $363,994 of bonus income was collected to benefit public education and North Dakota institutions.

10. The largest beneficiary of the permanent trusts is North Dakota's Common Schools Trust Fund, which benefits K-12 education. The Common Schools Trust Fund will distribute $103,067,000 to public schools in fiscal year 2016. That will account for an estimated $973 per student. The other 12 permanent trusts will distribute a total of $6,480,000 during fiscal year 2016 to institutional beneficiaries.

11. In my current position, I am familiar with the Final Rule promulgated by Environmental Protection Agency ("EPA") entitled: Final Rule: Carbon Pollution

Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.

12. The EPA's own assessment of the Final Rule assumes that approximately 677MWs of electrical generation is retired in North Dakota by 2016 and that an additional 558MW retires by 2018. These assumptions are part of the EPA required CO_2 emission reductions the State must show in a SIP submittal to the EPA in September, 2016. The EPA claims the State has flexibility in its choices; however, those significant CO_2 emissions reductions required by the Final Rule can only come from other lignite-fueled power plants in North Dakota. Thus, if North Dakota does not commit to implementing the EPA's specific assumptions, then North Dakota will simply have to make functionally equivalent CO_2 emission reductions from some other North Dakota lignite-fueled power plants.

13. The Final Rule will require a dramatic reduction in coal mining, however without knowing which mine or mines will be immediately affected by closure or reduced production, it is difficult to quantify the financial impact to the permanent trusts. However, since the Common Schools Trust and the other permanent funds own mineral acreage in all of North Dakota's lignite mines, a reduction in the production of coal will have an immediate and long-term detrimental financial impact due to the collection of substantially less royalties, bonus and rental

income. This in turn will impact North Dakota's support for public schools and state institutions across the state.

14. Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

Executed on October 26, 2015.

Lance D. Gaebe

Lance D. Gaebe

The foregoing Declaration of Lance D. Gaebe was subscribed and sworn before me by Lance D. Gaebe on October 26, 2015.

Witness my hand and official seal.

DIANE M NELSON
Notary Public
State of North Dakota
My Commission Expires January 26, 2018

Diane M Nelson

Notary Public

My commission expires:

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

STATE OF NORTH DAKOTA Petitioner, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, Respondent.	**DECLARATION OF L. DAVID GLATT** **Case No. 15-1380**

I, L. David Glatt, state and declare as follows:

1. My name is L. David Glatt. I am over 21 years of age and am fully competent and duly authorized to make this Declaration. The facts contained in this Declaration are based on my personal knowledge and are true and correct.

2. I am employed as the Chief of the Environmental Health Section ("EHS") North Dakota Department of Health ("NDDH"). I have been employed by the NDDH since 1983, and have continuously served as the Chief of the EHS since 2004.

3. The State of North Dakota, through the North Dakota Department of Health ("NDDH"), implements and enforces the State's various environmental regulatory programs, including state and federal air quality programs involving the regulation of stationary sources of air pollution. I am responsible for enforcing North Dakota's air quality regulations and those that also implement the federal

Clean Air Act ("CAA") involving programs for statutory sources under Titles I and V of the CAA – including CAA § 111(d).

4. North Dakota has for decades been aggressive in achieving the first stated purpose of the CAA: "to protect and enhance the quality of the Nations' air resources so as to protect the public health and welfare and the productive capacity of its population." CAA 110(b)(1), 42 U.S.C. § 741(b)(1).

5. I am familiar with the Final Rule promulgated by the U.S. and the Environmental Protection Agency ("EPA") ("Final Rule") entitled "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electronic Generating Units" 80 Fed Reg. 64,662 (Oct. 23, 2015).

6. EPA's Final Rule establishes very stringent requirements for North Dakota to dramatically reduce carbon dioxide emissions from existing coal-fueled power plants in North Dakota. Specifically, EPA's Final Rule requires an emission rate of 1,305 lb/MWh, which is 45% below North Dakota's 2012 baseline emission rate of 2,368 lb/MWh. The Final Rule provides North Dakota with an alternative to EPA's emission rate approach, where EPA prescribes a mass emissions limit of 20,883,232 tons. EPA's mass emissions compliance alternative requires a 37% reduction from the 2012 baseline of 33,370,886 tons.

7. Under the Final Rule, North Dakota must "choose" between two plan types—emission rate- or mass-based, to satisfy EPA's aggressive emission targets. In a rate-based State Plan, North Dakota must require affected power plants to satisfy an average amount of carbon dioxide per unit of power produced. The required target would be impossible for any existing North Dakota coal-fired

power plant to meet and continue operating for at least several reasons as follows: 1) the improvement of the current facility heat rate efficiencies through the implementation of available technologies and utilization of engineering best practices can only achieve, at best, 1 to 2 percent improvement in the heat rate, which would have minimal impact on the emission rates; 2) carbon dioxide capture technology has not been fully developed and is not available industry wide at a cost effective rate; 3) the availability of emission credits to continue facility operation is uncertain and may be cost prohibitive; and 4) there is insufficient time to plan and obtain necessary permits and regulatory approval and implement the reduced carbon emission plan that would comply with the established rule target dates. In a mass-based State Plan, North Dakota must cap the amount of carbon dioxide emissions that the whole sector of affected power plants can emit per year. This type of Plan must include some combination of enforceable emission limitations on power plants, and may include additional policy programs such as increasing renewable energy and tightening energy efficiency standards, and emissions trading. There are several issues and burdens associated with this approach, the least of which do not address anticipated load growth on top of compliance with the Final Rule, the large amount of renewable energy needed to be planned and implemented within the required time frame and the unknown impact of anticipated increased cost and reliability concerns of electricity distribution.

8. The Final Rule requires North Dakota to address not only the emitting sources but also goes outside the boundary of a stationary source and incorporates

non-emitting sources (e.g. wind and solar generation) and re-dispatching power to lower emitting units. In an effort to comply with the Final Rule, North Dakota would have to significantly increase the MW's produced by non-emitting sources (i.e. wind). It is roughly estimated that 3,300 wind towers and associated transmission lines must be constructed the next couple of years, with the associated credits staying in North Dakota. This monumental task would only minimally meet the required emission reduction goal in the state and would not address the anticipated load growth. Due to the fractured nature of the electric generation and transmission industry in the North Dakota, where no less than 5 separate companies distributing electricity to customers in up to 9 states with assets located in different states, a comprehensive and effective state plan will require coordination of all existing facilities and assets.

9. The Final Rule prevents the NDDH from exercising the authority and discretion entrusted to it, on behalf of North Dakota by CAA § 111(d), including taking into consideration the "remaining useful life of existing sources."

10. The Final Rule requires North Dakota to take into account reliability of the electrical system when developing North Dakota's plans which has never occurred with any other air pollution control rule. The re-dispatch of power, protecting the reliability of the electrical system and accounting for wind or solar generation have never before been requirements for the NDDH when implementing an EPA rule. These are requirements that exceed the existing statutory authority and discretion of the NDDH.

11. With regard to the September 2016 deadline contained in the Final Rule for submittal of a North Dakota State Plan, the NDDH will be required (1) to identify North Dakota's State Plans that are "under consideration," (2) provide an "appropriate explanation" for any additional time the NDDH or State of North Dakota will need, and (3) describe how the NDDH and North Dakota has provided for "meaningful engagement" with the public leading up to the submission. 80 Fed. Reg. at 64,856. Satisfying these three steps for the September 2016 deadline requires significant *immediate* effort and expenditures by the NDDH. This will require, among other things, identifying the amount of natural gas and renewable capacity that can be developed; understanding the timeframe on which such new capacity could be developed consistent with the public's ability to obtain reliable, affordable energy; engaging in intrastate communications with public utilities commissions; engaging in interstate outreach to other States possibly interested in multistate options; holding meetings with the public and industry; and, determining what implementing legislation could plausibly be adopted by the North Dakota legislature that meets every two years. The NDDH must also assess what measures are needed to obtain credits under the Clean Energy Incentive Plan, because the 2016 submission must include a statement of intent if North Dakota wishes to participate.

12. The Final Rule also requires the NDDH to submit an "update" to EPA by September 2017, describing the type of approach it will take in the final plan submittal and to draft legislation or regulation for this approach." 80 Fed. Reg. at 64, 859.

13. As to the September 2018 date set forth in the Final Rule for final State Plan submittals to EPA, that deadline also requires immediate expenditures by the NDDH. The immediate expenditures include staff time to review and interpret the new rule, public outreach and communication, modeling to determine anticipated cost and reliability impacts and evaluation of how the Clean Power Plan will impact and potentially postpone proposed new energy development in the state.

14. The NDDH has evaluated the Final Rule and determined that EPA evaluated the effects of the Final Rule using its Integrated Planning Model (IPM). In this analysis, EPA projected that six units of coal-fired generation (totaling more than 1,300 MW) in North Dakota would retire by 2020. This included the two units of the R.M. Heskett Station, M.R. Young Station Unit 1, Coyote Station, Spiritwood Station and one unit of the Coal Creek Station. In 2014, these units produced 9,672,068 megawatt-hours of electricity or 27% of the total generation in North Dakota. Based on the Annual Emissions Inventory Reports that were submitted to the NDDH for the facilities, the units consumed nearly 8 million tons of lignite in 2014. The R.M. Heskett Station combusted 517,703 tons, the M.R. Young Station Unit 1 - 1,545,188 tons, Coyote Station - 2,248,483 tons, Spiritwood Station - 91,017 tons and Coal Creek Station Unit 1 - 3,407,090 tons. This includes 2.77 million tons from the Beulah Mine, 1.55 million tons from the Center Mine and 3.53 million tons from the Falkirk Mine. Based on EPA's scenario, the Beulah Mine would shut down and production from the Center Mine

reduced by approximately 40%. Production at the Falkirk Mine would be reduced by approximately 50%.

15. Although EPA indicates this is just one possible approach North Dakota may take to comply with the Final Rule, it is unfortunately a realistic approach given the compliance requirements imposed on North Dakota by the Final Rule. Because North Dakota must reduce it emission rate by 45%, approximately each megawatt of North Dakota coal-based generation must be matched with a megawatt of zero carbon emitting generation in order to achieve compliance with the Final Rule. Energy efficiency improvements at North Dakota power plants are expected to only produce a 1-2% increase in efficiency. Since there are no demand side energy efficiency programs (formerly Building Block 4) in North Dakota, the benefit from demand side energy efficiency is expected to be minimal. Compliance can only be accomplished by retiring coal plants, greatly curtailing the use of the affected units or purchasing emission rate credits (ERC) or allowances. If coal generation is not curtailed, the affected utilities will have to purchase ERCs or mass allowances. At this time, the number of ERCs or allowances available is unknown because the trading program has not even been developed. This also makes the cost of the ERCs and allowances unknown. EPA has estimated the cost to reduce carbon dioxide emissions at $30 per ton. 80 Fed. Reg. at 64,749. The cost to North Dakota utilities (ultimately North Dakota and other ratepayers) for reducing emissions could be $375 million per year. Based on 2013 data, this would increase the cost of electricity generation by coal-fired units in North Dakota by as much as 58%. With an expanding economy, growing

population and a large load growth predicted for western North Dakota because of oil and gas development, this makes planning extremely difficult and pushes utilities toward coal-fired plant closures. If plant closures occur, there is insufficient time to plan, design and construct new generation and transmission systems before the initial compliance date of 2022.

16. Developing a North Dakota plan that complies with the Final Rule represents an unprecedented challenge for both the NDDH and the utilities that operate the affected power plants within North Dakota. I expect that development of the plan will require a minimum of 4 full time employees for the three years from September 2015 to September 2018. The plan development effort is expected to cost the NDDH an estimated $2.1 million. North Dakota's Legislature meets every two years and concluded its last session earlier this year. EPA's Final Rule was made public and signed after the end of the North Dakota 2015 legislative session. The North Dakota legislature was not aware of these expenses and did not include resources for the NDDH to address them.

17. The NDDH's expenditure of human and fiscal resources will immediately redirect the NDDH from serving its full regulatory mission, as directed by the North Dakota legislature, causing further irreparable harm. Designing North Dakota's Plan will also take time away from the NDDH's obligation to regulate and protect North Dakota's natural resources.

18. The NDDH submitted extensive written comments on EPA's proposed rules. The concerns North Dakota expressed have been greatly compounded by EPA's Final Rule, which imposed dramatically more stringent

compliance requirements on North Dakota. Remarkably, EPA's Final Rule imposes a four-fold increase in EPA-mandated emission reduction requirements for North Dakota over those EPA initially proposed. The Final Rule requires North Dakota to reduce its carbon dioxide emission rate by 44.9% or 420% more than the Proposed Rule.

19. The Final Rule contains numerous significant, material elements of central relevance to the outcome of the Final Rule that EPA did not identify in the Proposed Rule. As such, the NDDH and the public were not provided with any opportunity to comment on these new and wholly unexpected provisions. Further, the NDDH nor members of the public could not have reasonably anticipated these changes and they are not a "logical outgrowth" of the Proposed Rule. The NDDH would have commented on these issues had EPA identified them. EPA can only address these unacceptable circumstances by providing the NDDH and the public with a new and meaningful notice and comment period.

20. Below are some aspects of the Final Rule for which EPA did not properly give notice in the proposal:

(a) EPA issued voluminous highly technical data and support documents essential to a thorough evaluation of the Proposed Rule as late as October and November 2014, just days before EPA's close of the public comment period. These documents covered fundamental aspects of the Proposed Rule, ranging from building block methodology, the calculation of state-specific goals, emission reduction compliance trajectories, and the translation of emission rate-based goals to mass-based equivalents. This left insufficient time for the NDDH to meaningfully study, evaluate, and comment on the Proposed Rule.

(b) EPA failed to identify in the Proposed Rule all of the potential changes it intended to make to allowances and compliance credits and its intention to undermine existing state Renewable Portfolio Standards programs with its ill-defined Emission Reduction Credit (ERC) program and the mass-based and rate-based trading programs.

EPA's decision to include in the Final Rule provisions that disallow credit for a significant portion of North Dakota's existing renewable energy is not a logical outgrowth of the Proposed Rule and could not be anticipated.

(c) EPA did not identify in the Proposed Rule that renewable energy facilities constructed before 2013 would not receive compliance credits during compliance years. Nor did EPA identify that those facilities constructed before 2018 would be denied extra compliance credit from 2020-2021 under the Clean Energy Incentive Program (CEIP) because the CEIP does not credit any facilities built before the final State plan submittal, which is due on or about September 6, 2018.

(d) EPA revised its "Building Blocks" methodology without giving the public an opportunity to comment on the material changes. The Rule's Building Blocks are the foundation of the performance standards, yet the NDDH did not have an opportunity to comment on the new assumptions for heat-rate improvements for coal plants, dispatch rates for natural gas plants, and expansion of renewable generation.

(e) The Final Rule provides an adjustment to the baseline fossil fuel-fired generation for several states due to high hydroelectric generation in 2012. These states include South Dakota, Minnesota and Montana which all border on North Dakota. In 2012, hydroelectric generation in North Dakota was 128% of normal. However, EPA denied North Dakota an adjustment to its fossil generation based on arbitrary criteria including 1) generation had to be greater than 10 percent of total generation, 2) there had to be an increase of greater than 5 percent hydro generation relative to the 1990-2012 average generation, and 3) there had to be a greater than 5 percent adjustment to the state's fossil fuel generation (*CO_2 Emission Performance Rate and Goal Computation Technical Support Document for the CPP Final Rule; p.28*). The NDDH had no chance to provide comment on these criteria and the adjustments that were made.

(f) In addition, EPA applied the Building Blocks to affected sources in a new manner. The performance standards in the Final Rule were developed by applying the Building Blocks to three regional interconnection systems. This novel approach was not contemplated by EPA in the proposed rule. In sum, the Building Blocks and the manner in which they were applied are indisputably of central relevance to the Final Rule.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

Executed on October 29, 2015.

L. David Glatt

The foregoing Declaration of L. David Glatt was subscribed and sworn before me by L. David Glatt on October 29, 2015.

SHERRI A. JAHRAUS
Notary Public
State of North Dakota
My Commission Expires Oct. 18, 2020

Witness my hand and official seal.

Sherri A. Jahraus
Notary Public

My commission expires: 10/18/2020

e:\dixie\nr\health dept\declaration of dave glatt .docx

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

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ________

DECLARATION OF RONALD W. GORE

I, Ronald W. Gore, hereby declare as follows:

1. I am the Chief of the Air Division within the Alabama Department of Environmental Management (ADEM). I have been employed by ADEM for 41 years. As part of my duties, I am responsible for the Division's development of State plans to implement federal air quality rules and regulations.

2. Based on my position, I have the personal knowledge and experience to understand what steps the State will need to undertake in response to EPA's finalized *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, 79

Fed. Reg. 34,830 (June 18, 2014) ("Section 111(d) Rule" or "Rule"). This includes personal knowledge and experience in preparing a State plan consistent with the Rule. Under that Rule, the State must submit a plan to the Environmental Protection Agency ("EPA") by late summer of 2016, absent special circumstances.

3. Based on my knowledge and experience, I believe that developing Alabama's response to the Section 111(d) Rule will be the most complex air pollution rulemaking undertaken by ADEM in the last 41 years. I have been responsible for and worked on many State plans designed to be submitted to and approved by EPA, including plans for attaining air quality standards, construction and operating permit plans, visibility rules, etc. The Clean Air Act recognizes the time and resources necessary to draft and finalize such plans by providing three to five years, at a minimum, for States to submit them. In the 111(d) Rule, EPA requires that States submit a vastly more complex rule in one to three years.

4. EPA has proposed that GHG reductions can be maximized by viewing the electric utility system in a very broad way, i.e., that States can and should regulate facilities and consumer behavior in ways never before considered to be authorized by the CAA. This broadening of authority means that ADEM will likely have to seek authorization from the State Legislature to implement EPA's proposal. It is likely that other Alabama agencies will need to participate in enforcing parts of Alabama's plan and broad new State Legislative authority will be needed for them as well. ADEM historically has been the agency solely responsible for air quality compliance in the State. Having several other State agencies closely involved in the development and administration of air quality rules presents a daunting challenge for ADEM.

5. Since EPA proposed the Section 111(d) Rule in June of 2014, ADEM has expended considerable resources in attempting to understand the State's necessary response. Two employees have been assigned full-time to analyzing the proposal. I estimate that in addition to the two full time employees mentioned above, an additional three man years[1] of effort are being expended by fifteen other employees who devote part of their work time on 111(d) issues. In total, I estimate that five man-years of effort, (equating to approximately $475,000 in additional personnel costs per year) are being deployed at present responding to the Section 111(d) Rule. Efforts on which resources have been spent include, but are not limited to, the following examples:

- Checking EPA's calculations and assumptions on the emissions reduction goals the State should attain
- Generating possible responses to check whether they are achievable in practice
- Meeting with trade groups, EPA, other states, environmental groups, individual utilities, etc. to consider their input and viewpoints
- Traveling to and speaking at EPA's Regional Public Hearing
- Traveling to and participating in several national workshops on Section 111(d)
- Holding many internal meetings to facilitate information flow up and down the management chain

6. Now that the Section 111(d) Rule has been finalized and adopted, additional man-years of effort will be needed for ADEM to prepare and submit a plan. Assuming ADEM chooses to prepare and submit a plan, my best estimate is that eight man-years of effort (equating to $760,000 per year for several years) would be needed.

[1] The approximate dollar value of a "man year" is estimated to be $95,000, counting salary, fringe benefits, and overhead.

7. Should the Court rule that EPA has overstepped its authority, ADEM's efforts would cease.

I declare under penalty of perjury that the foregoing is correct.

Executed on this 6th day of August 2015, in Montgomery, Alabama.

____

Ronald W. Gore

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

Utility Air Regulatory Group,	)	
	)	
Petitioner,	)	
	)	
v.	)	Case No. __________
	)	
U.S. Environmental Protection Agency,	)	
	)	
Respondent.	)	

DECLARATION OF KIM GREENE

I, Kim Greene, declare:

1. I am the Chief Operating Officer ("COO") of Southern Company. As COO, among other duties, I oversee generation, transmission, engineering and construction services, wholesale energy, fuels, and system planning at Southern Company. I hold a Bachelor's Degree in Engineering Science and Mechanics from the University of Tennessee, a Master's Degree in Biomedical Engineering from the University of Alabama at Birmingham, and a Master's in Business Administration from Samford University. I began with the Southern Company system in 1991 as a Mechanical Engineer. I served in various roles, throughout the Southern Company system, as well as at Tennessee Valley Authority and Mirant, before I returned as the Chief Executive Officer of Southern Company Services, Inc. beginning in April 2013. I served in that capacity until I began my current position as COO on March 1, 2014.

2. In this declaration, I identify numerous impacts to the Southern Company system and its customers if we are required to undertake the steps the Environmental Protection Agency ("EPA") itself has forecasted in its Regulatory Impact Analysis of the Clean Power Plan. Based

on EPA's Integrated Planning Model ("IPM") analysis, the impacts to the Southern Company system and its operating companies include:

- The premature shuttering of over 9,000 megawatts ("MW") of fossil fuel-fired units, constituting approximately 20% of the Southern Company system's generating capacity, with more than 8,000 MW retired in 2016 alone;
- Higher production costs and an insufficient reserve margin, resulting in increased customer costs of approximately $2 billion in 2016-2017;
- The undertaking of thirty-five independent transmission projects to ensure reliability, totaling approximately $1 billion, with costs in 2016-2017 of over $185 million; and
- Costs in 2016-2017 of $950 million to compensate for impacts to the fuels program.

3. Based on EPA's results, and because it takes many years to plan and implement changes to our generating and transmission resources, the Southern Company system and its operating companies would have to begin activities immediately in 2016 and 2017 regardless of the specifics of any state or federal plan ultimately adopted to implement the Clean Power Plan. This is because, according to EPA, the retirements identified by the IPM are already the current "best assessment of likely impacts of the [Clean Power Plan] under a range of approaches that states may adopt." EPA, Regulatory Impact Analysis 3-11 (Aug. 2015) ("RIA"), *available at* http://www3.epa.gov/airquality/cpp/cpp-final-rule-ria.pdf. Moreover, as explained below, many of these impacts could not be reversed once the changes to the generating and transmission resources have begun.

4. Southern Company is the leading energy supplier in the Southeastern United States, delivering 4.5 million customers safe, reliable, and affordable electricity service generated from a full portfolio of energy resources, including fossil, nuclear, solar, and hydro-electric generating

plants. Southern Company's subsidiaries include four vertically integrated, regulated electric utilities—Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. As the COO, I and my staff are charged with ensuring the reliability and cost-effectiveness of our generation and transmission services.

5. Southern Company is obligated and committed to delivering safe, reliable, and affordable electricity to its customers. As a result, we have and apply tools to assess and project the status of our power plants and transmission network to ensure reliability and availability as part of an annual resource planning process.

6. Southern Company has a planning horizon of forty years. Most of the activities we undertake require years, and sometimes decades, to plan and execute. Depending on the type of generation (combustion turbine, natural gas combined cycle ("NGCC"), nuclear, etc.), new generation plants require from four to seventeen years to obtain regulatory approvals, plan, site, design, permit, construct, and commission. For example, a new NGCC takes approximately seven to eight years to obtain regulatory approvals, engineer, procure, construct, and place in service. Accordingly, if a new NGCC were needed to be placed into service in 2022, activities to meet that projected in-service date would have to begin immediately. Likewise, identifying, developing, planning, and then building transmission projects can require years to implement, particularly when property rights for new power line corridors must be obtained. In sum, the nature of the utility planning process requires us to take actions well in advance of a forecasted event or need in order to ensure that we maintain our ability to provide the most cost-effective and reliable electric service possible to our customers.

7. I provide this declaration in support of the Utility Industry's motion to stay the EPA's "Carbon Pollution Emission Guidelines for Existing Sources: Electric Generating Units" ("Final

Rule" or "Clean Power Plan"). EPA, *Carbon Pollution Emission Guidelines for Existing Sources: Electric Generating Units* (signed Aug. 3, 2015), *available at* http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule.pdf.

8. I hereby rely on the information provided in the declarations of Jim P. Heilbron, John L. Pemberton, Michael L. Burroughs, and R. Allen Reaves, Jr., on behalf of Alabama Power, Georgia Power, Gulf Power, and Mississippi Power, respectively. Additionally, Southern Company Services, Inc., as agent for its operating companies, has reviewed and analyzed EPA's Final Rule and EPA's related impact assessment and associated modeling. The declarations on behalf of the aforementioned companies rely on such analysis.

9. This declaration is based on my personal knowledge of facts and analysis conducted by my staff.

SUMMARY OF EPA'S CLEAN POWER PLAN

10. On August 3, 2015, EPA promulgated its Final Rule under Section 111(d) of the Clean Air Act. EPA's Final Rule is the most complex and far-reaching environmental regulation the utility industry has ever faced. Based upon my considerable experience in the utility industry, the Clean Power Plan would increase electricity prices to customers while jeopardizing reliability. The Final Rule will result in a complete restructuring of the nation's electric sector and negatively impact America's energy security.

11. The Final Rule requires, starting with enforceable targets in 2022, that utilities be on track to reduce CO_2 emissions 32% from 2005 levels by 2030 on a national basis—an extremely aggressive objective that, standing alone, would require years of lead time to achieve. However, the EPA expects utilities to take steps that will achieve 80% to 90% of that goal *before* the compliance period even begins in 2022. EPA readily admits that "achieving reductions by 2022"

will require "actions and investments that *yield* CO_2 emission reductions *prior to 2022*." Final Rule at 42 (emphasis added).

12. The Final Rule establishes interim and final national "performance rates" for existing fossil fuel-fired steam boilers and for NGCCs. The interim performance rates, which apply from 2022 through 2029, are established as the emission of 1,534 lbs CO_2/MWh and 832 lbs CO_2/MWh for fossil fuel-fired steam boilers and NGCCs, respectively. Beginning in 2030 and thereafter, the fossil fuel-fired steam boiler and NGCC performance rates drop to 1,305 lbs CO_2/MWh and 771 lbs CO_2/MWh. EPA used these interim and final national performance rates to establish state-specific, rate-based and mass-based goals, which were calculated by applying the performance rates to each state's 2012 generation mix. States are told to adopt an "emissions standards" plan that either applies the performance rates to affected units or applies other rate- or mass-based standards to affected units that individually, or in the aggregate, achieve EPA's goals upon implementation. States may alternatively adopt a "state measures" plan that includes, at least in part, measures imposed on entities other than existing electric generating units, as well as a backstop of federally enforceable standards for individual power plants that are triggered if the state measures do not achieve the required emission reductions.

13. The states have the obligation to plan for compliance, but the burden is on the owners and operators of affected units to comply with EPA's Final Rule. Existing units cannot meet the new performance rates through any adequately demonstrated technological or operational changes at the unit. The reason the Final Rule is so different from any previous environmental regulation is that there are no demonstrated "control technologies" that will achieve the standards. Instead, in order to comply, utilities must curtail their generation, shutter plants, shift generation to lower-emitting resources, produce less electricity, and/or purchase credits or allowances under a trading

program that has not yet been created. This regulation of the utility system, which effectively mandates the replacement of one type of power generation with a different type of power generation, is unprecedented.

14. It is plain that, in light of the scope and stated purpose of EPA's Clean Power Plan, the rule will have unprecedented consequences for the Southern Company system and its customers, because "it will do more than just regulate—it will change markets." Gina McCarthy, Administrator, Envtl. Prot. Agency, Remarks on U.S. Climate Action at the American Center (Aug. 26, 2015). Moreover, although some of the dates in the Final Rule may seem far off, as discussed above, our planning process and horizon makes it patently clear that many of these consequences will begin to occur immediately. EPA itself has forecasted the consequences to the Southern Company system and other utilities as part of its RIA. Specifically, using the IPM developed by ICF International, EPA has identified a "compliance solution," i.e., the unit-level retirements, shifts in generation, and specific new generation that define EPA's "least cost way to achieve the state goals . . . ." RIA at ES-4. Based on EPA's compliance solution, we were able to determine some of the immediate and significant impacts to our system's generation fleet and transmission system, including (1) inadequate reserve margins, (2) the need for transmission reliability projects, and (3) costs of changing fuel procurement.

EPA'S REGULATORY IMPACT ANALYSIS

15. Predicting the impacts on the electricity sector of a significant new regulatory program (such as the Clean Power Plan) requires sophisticated computer modeling. Due to the significant changes in the Final Rule from the Proposed Rule, EPA's own analysis and modeling of the Final Rule is the best current predictor of its impacts and effects. EPA's results can be used to assess what individual companies would have to do in order to comply with the Clean Power Plan now. Of course, states and individual utilities are working to make their own assessments

under existing state regulatory processes. However, given that EPA has justified the rule based on this modeling analysis, it must be considered while states and utilities begin to evaluate future actions.

16. IPM is a multi-regional, deterministic, and dynamic linear programming model developed by ICF Consulting. EPA asserts that it employs IPM to "examine air pollution control policies" and "project power sector behavior under future business-as-usual conditions" throughout the contiguous United States. *Id.* at 3-1.

17. EPA uses the IPM to perform most of the compliance cost, emissions, economic, and energy impact analyses for the Final Rule. *Id.* EPA's analysis included using IPM "to project likely future electricity market conditions" both "with and without the Clean Power Plan Final Rule." *Id.*

18. EPA has used IPM "extensively" for "over two decades to better understand power sector behavior under future business-as-usual conditions and to evaluate the economic and emission impacts of prospective and final environmental policies." *Id.* at 3-2, 3-4. EPA has used IPM to evaluate the impacts of: the Clean Air Interstate Rule; the Cross-State Air Pollution Rule; the Mercury and Air Toxics Standards; the proposed Carbon Pollution Standards for New Power Plants; the Disposal of Coal Combustion Residuals from Electric Utilities Guidelines; the Steam Electric Effluent Limitation Guidelines; and the Cooling Water Intakes Rule. *Id.* at 3-4.

19. The IPM platform EPA used to analyze the Final Rule is version 5.15, which was updated in August 2015. *Id.* at 3-5. EPA declares that version 5.15 was carefully updated from the version used to analyze the Proposed Rule to produce EPA's "best assessment of likely impacts of the [Clean Power Plan] under a range of approaches that states may adopt." *Id.* at 3-11. The updates consisted of

> routine calibrations with the Energy Information Agency's (EIA) Annual Energy Outlook (AEO), including updating the electric demand forecast consistent with the AEO 2015 and an update to natural gas supply. Additional updates, based on the most up-to-date information and/or public comments received by the EPA, include unit-level specifications (e.g., pollution control configurations), planned power plant construction and closures, and updated cost and performance for onshore wind and utility-scale solar technologies. This IPM modeling platform incorporates federal and most state laws and regulations whose provisions were either in effect or enacted and clearly delineated in March 2015. This update also includes two non-air federal rules affecting EGUS . . . . Additionally, all new capacity projected by the model is compliant with Clean Air Act 111(b) standards, including the final standards of performance for GHG emissions from new sources.

Id. at 3-5. These nuanced updates support the Agency's view that "[t]he model is designed to reflect electricity markets as accurately as possible," subject, of course, to the accuracy of the model's inputs. *Id.* at 3-2.

20. EPA avows that IPM is a "state-of-the-art, peer-reviewed, dynamic linear programming model" used to estimate outcomes of pollution-abating policies, *id.* at 3-1, and thus would appear to be carefully monitored to ensure it forecasts the compliance solution for the Final Rule "as accurately as possible." EPA, Technical Support Document: Resource Adequacy and Reliability Analysis 2–3 (Aug. 2015).

CONSEQUENCES IDENTIFIED IN EPA'S REGULATORY IMPACT ANALYSIS

21. EPA's compliance solution identifies almost 80,000 MW of fossil-fired steam electric generating units that will retire nationally by 2016. Of that, Southern Company must retire over 8,000 MW of fossil fuel-fired units.

22. As reflected by the declarations of Jim P. Heilbron, John L. Pemberton, Mike L. Burroughs, and R. Allen Reaves, these impacts affect each of our operating companies and its customers. Based on EPA's compliance solution, we have determined some of the immediate and irreparable consequences of these premature retirements for the Southern Company system as a whole. Even if the retirements identified by EPA in its compliance solution did not occur

until 2022 (the first year of the interim compliance periods), many of the actions identified below would still need to begin in 2016-2017 and would have significant costs in order to minimize the impacts on the cost-effectiveness and reliability of delivering electric service.

23. It is important to note that EPA's compliance solution includes prescriptive levels of demand side energy efficiency that are not adequately demonstrated in the states comprising our service territory. EPA "hard-coded" into the model an annual incremental demand reduction rate rising to 1.0% of electricity demand for each state. RIA at 3-13. In contrast, the states in which the Southern Company system serves achieved incremental demand reduction rates of 0.07% to 0.27% in 2012. Because EPA's "hard-coded" levels are not likely to be achieved, fossil fuel-fired sources will carry an even greater burden of compliance under the Final Rule, which will amplify the costs and reliability impacts described below.

Impacts to Reserve Margins

24. The retirements shown in EPA's compliance solution reflect Southern Company system retirements of over 8,000 MW in 2016 (and over 9,000 MW in total). While each operating company has its own obligation to meet customer needs, the operating companies' generating and transmission resources are physically connected to and integrated with the rest of the Southern Company system, and balancing combined customer demand and generation is done at the system level.

25. The premature retirement of over 8,000 MW in 2016 would negatively impact the reserve margin of the Southern Company system. A reserve margin is a measure of the amount of resources available in excess of forecasted demand. Southern Company's long-term reserve margin is established at 15% and is necessary to maintain reliability on the system, taking into account risks due to non-normal weather, unit outages, and inherent inaccuracies in demand forecasts. EPA's compliance solution would dangerously reduce Southern Company's long-term

reserve margin below the established 15% to 4.8% in 2016 and 2.9% in 2017. These drastically reduced reserve margins would have significant reliability and cost implications. Furthermore, the Company's response to these reliability and cost implications cannot be unwound, because once an electric generating unit is retired, it is not feasible to return the same unit to service.

26. The Southern Company system's reserve margin depends not only on physical generating assets but also on customer participation in what are referred to as "demand-side options." These demand-side options are agreements with some customers to interrupt some or all of their service when needed to maintain reliable service to the system (for example, a factory with three production lines may agree that it will shut down one or more production lines for a certain time period when asked to do so).

27. If such demand-side options were no longer available, the Southern Company system's reserve margin would be negative in 2016 and 2017 under EPA's compliance solution. This would mean there are not enough generation resources to match even forecasted demand under normal weather conditions, much less under extreme weather conditions. An example of demand-side options becoming unavailable is if the factory participant (described above) chooses to exit the program because its power was interrupted frequently rather than rarely.

28. The premature retirement of over 8,000 MW of generation in 2016 would also drive the Southern Company system's reliability far outside of common industry practice. One industry measure of sufficient generating resources is to avoid having more than one customer electricity service interruption over a ten-year period. The Southern Company system currently has sufficient generation to be below this measure. However, the retirement of over 8,000 MW in 2016 would drive that measure for the Southern Company system to twenty-four events every ten years, or twenty-four times higher than common industry practice.

29. The retirements and generation shifts shown in EPA's compliance solution would also lead to an increase in generation production costs, because more expensive generation will need to operate to partially replace the less expensive generation that is retired or utilized less. In addition, there would be an impact on customers associated with the cost of unserved energy. Unserved energy is customer demand for electricity that cannot be met due to generation deficiencies. This unserved demand is manifested as controlled, temporary shut-off of electric service in a rotating manner to groups of firm load customers in order to maintain compliance with North American Electric Reliability Corporation ("NERC") standards. Customers with unmet demand suffer economic costs. The economic impact to our retail and wholesale customers from such higher production costs and unserved energy would be approximately $2 billion during the 2016-2017 time period.

30. If these retirements occurred in 2022, the reserve margin impacts would be deferred until 2022. However, even if the retirements occurred in 2022, the Southern Company system would still have to begin taking action immediately in 2016-2017 to prepare for the retirements. For example, if the Southern Company system sought to replace the retired generation through the construction of NGCCs in order to reach the target planning reserve margin in 2022, the planning process would have to begin immediately, and there would be $158 million of expenditures in 2016-2017.

Impacts to Transmission

31. A preliminary screening analysis was performed to assess the impacts to the transmission system, including needed transmission projects and estimated costs, due to the unit retirements identified in EPA's compliance solution. The preliminary screening analysis was limited to power flow analyses developed with transmission planning models for the years 2016 and 2022 to monitor thermal and voltage constraints in our transmission system. Additional transmission

analyses, such as dynamic analysis and assessments of off-peak system conditions, would need to be performed to identify a comprehensive set of transmission projects needed to maintain reliability. It would take many months to perform these additional transmission analyses, and thus they are not included in this declaration. It is anticipated that such analyses would likely identify additional, significant transmission impacts due to the unit retirements identified in EPA's compliance solution.

32. As a result of the unit retirements identified in EPA's compliance solution, a significant amount of replacement generating capacity will be needed to maintain resources adequate to reliably serve the demand for electricity. For purposes of our preliminary screening analysis, we assumed this replacement generating capacity would have to be procured from third-party resources because the Southern Company system would not be able to build sufficient generation to replace the missing capacity by the 2016 closure dates identified in EPA's compliance solution. Under these resource assumptions, our analysis showed that in order to accommodate the unit retirements identified in EPA's compliance solution, numerous transmission projects must be undertaken in the Southern Company system's service territory to maintain compliance with NERC Reliability Standards. Specifically, and as identified in the declarations of Messrs. Heilbron, Pemberton, Borroughs, and Reaves, we have determined that at least thirty-five additional transmission projects to Southern Company's transmission system at a cost of approximately $1 billion dollars will be required. Such transmission projects include significant enhancements to the existing transmission system as well as nine new line and substation projects. The expenditure required in 2016-2017 to support these projects is in excess of $185 million. Furthermore, and most critically, due to lead times required to complete these transmission projects, the transmission projects cannot be placed in service by the unit retirement

dates identified in EPA's compliance solution. The new line and substation projects will require from five to eight years to complete, and projects at existing lines and substations will take approximately one to five years to complete. As a result, there will be increased risk to system reliability until these projects can be completed. Once new construction projects have begun, because they involve acquisition of long-term property rights, they cannot be easily unwound.

33. Even if the retirements identified by EPA for 2016 did not occur until 2022, when compliance targets set by the Clean Power Plan become effective, many of the actions identified above would not only still be necessary but would also still need to begin in 2016-2017 in order to minimize the reliability impacts of delivering electric service. Specifically, to accommodate those retirements, the Southern Company system would still have to begin the transmission projects that require five years or longer to complete, and the expenditure to support those projects would be in excess of $87 million in 2016-2017.

Impacts from Fuel Contracts and Inventories

34. Under EPA's compliance solution, our operating companies will incur costs of approximately $950 million in the 2016-2017 timeframe due to the impact on our fuel contracts and fuel inventories. These costs result from the closures that EPA has identified in the compliance solution. Specifically, we assessed: (1) the incremental cost to reduce coal contract volumes, assuming diverting remaining coal shipments to other coal units whenever possible; (2) liquidated damages associated with transportation contract cancellations; (3) costs associated with other fuel-related impacts, such as incremental costs to reduce other materials' contract volumes, including limestone, gypsum, fuel oil agreements, and railcar leases; (4) costs to cancel firm transportation agreements for natural gas to retired units, assuming no remarketing capability; and (5) the increase in system production cost, which results from forcing coal units to operate in order to consume the retiring units' coal inventories (planned burn). Once contracts

are cancelled, they cannot easily be reinstated. Even if some of these costs could be mitigated under force majeure, substantial impacts would clearly remain.

Costs to the Southern Company System from Fuel Contracts and Inventories

Fuel Costs	Estimated Cost in 2016-2017 ($2015)
Coal Commodity Agreements	$325M
Coal Transportation Agreements	$415M
Additional Fuel Related Impacts	$110M
Gas Firm Transportation Cancellations	$40M
Coal Planned Burn	$60M
Total $	**$950M**

Conclusion

35. Unless the Final Rule is stayed, EPA's compliance solution shows immediate and irreparable impacts on the Southern Company system and its customers. These impacts are caused by the retirement of significant generating capacity that EPA's model shows occurring in 2016, even though this capacity would otherwise serve the system's electricity needs for many years.

36. Direct impacts to the Southern Company system in excess of $1.1 billion in 2016-2017 result from the need to undertake new transmission projects (which could not be completed in 2016) and from the impacts to fuel contracts and inventories.

37. The retirements identified in EPA's compliance solution would also negatively affect our customers by increasing their cost for electricity and risking reliability. The economic impact to

customers from higher production costs and unserved energy would be approximately $2 billion in 2016-2017.

38. Even if the retirements identified in EPA's compliance solution for 2016 occur in 2022, the Southern Company system would be required to take action and incur approximately $245 million in costs in 2016-2017 to ensure the operating companies continue to provide safe, reliable, and affordable electricity service.

Respectfully submitted,

Kim Greene

Kim Greene
Southern Company, Chief Operating Officer

October 13, 2015

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

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos.

DECLARATION OF THOMAS GROSS

I, Thomas Gross, hereby declare as follows:

1. I am the Chief of the Monitoring and Planning Section in the Kansas Department of Health and Environment Bureau of Air Quality. I have been employed by the Kansas Department of Health and Environment for 39 years. As part of my duties, I am responsible for managing the group that develops state plans to implement federal air quality rules and regulations.

2. Based on my position, I have the personal knowledge and experience to understand what steps the State will need to undertake in response to EPA's Section 111(d) Rule, including the preparation of a state plan consistent with the Rule.

3. Based on my work, I have deteiiiiined that implementing the Section 111(d) Rule presents a complicated endeavor, including the creation of the state plan. Based on my experience in working in other state plans and state implementation plans (SIPs) such as

mercury, regional haze, ozone and lead, the Section 111(d) plan will likely take from three to five years, with the longer time frame being required if a multi-state plan is prepared.

4. Creating a plan of the type envisioned under Section 111(d) is a complicated endeavor for several reasons. First is the large potential for stranded investments in the State of Kansas. Kansas is in a unique situation due to the proportion of coal-fired units subject to the BART requirements of the regional haze program. The six largest coal-fired units in Kansas made significant investments in criteria pollutant emission reduction equipment in the last three to four years to comply with EPA's regional haze program. More than $3 billion has been earmarked for these projects that have recently been completed. The financing for these improvements to control criteria pollutants will not mature by the time the Clean Power Plan interim deadlines will require closure of some of these plants to meet the state goal. These plants are operating at control efficiencies that are very near to new BACT rates for new facilities. Although not new, the investments made in pollution control equipment are significant and should be allowed to be amortized over a greater time period than allowed under the Rule.

5. The Rule uses three building blocks to develop the CO_2 emissions goals for each state. Building block number one, regarding heat rate improvements, sets a goal that is not achievable across the entire fleet of affected units in Kansas. A major impediment to the type of boiler upgrade projects that could achieve significant heat rate improvements is the fact that they would likely trigger a Best Available Control Technology (BACT) review as part of a Prevention of Significant Deterioration (PSD) permit process. If a plant were not yet equipped with a SCR unit to control NO_x, a heat rate improvement project that might cost $5 million could turn into an SCR project for NO_x reductions with a price tag of $100 million as a result of a BACT review conducted as part of a PSD permit review process. Smaller scale heat rate improvement projects

that would not trigger a BACT review will not be able to achieve the 4.3% goal contained in this building block.

The third building block requires affected units to achieve CO_2 emissions reductions off the footprint of the affected unit. In Kansas, this building block has the greatest potential for CO_2 emission reductions. Building block number three sets a goal for renewable energy generation based on the potential for wind development in Kansas. There are a limited number of viable sites for wind energy development in Kansas. The number is limited by (1) the listing of the lesser prairie chicken as a threatened species under the Endangered Species act; (2) state policy of protection of Flint Hills ecosystem; and (3) lack of adequate transmission lines or transmission bottlenecks. Kansas utilities will have to compete with neighboring states contracting with merchant wind developers for these limited sites.

Additionally, the renewable energy statutory mandate was changed to a goal during the 2015 legislative session. While Kansas utilities currently meet the requirements of the revoked standard and were on a path to meet the 2020 goal, the shortfalls in meeting the goals established in building block one would have to be made up in building block three. There is a large potential for wind energy development in western Kansas when upgraded transmission lines to out-of-state markets are completed. However, the final Rule does not grant any emission reduction credits to Kansas utilities for the zero emissions wind energy produced in Kansas that is sold out-of-state. In the Rule the renewable energy credits follow the electricity to the out-of-state utility with the power purchase agreement.

To capture credit for the renewable energy sold to out-of-state markets, Kansas will have to participate in some form of interstate program that would include states receiving Kansas wind energy. Such a program would require new statutory authority, significant groundwork in determining which states would participate, resources to develop interstate agreements to create the entity that would administer the trading program, and time to create parallel regulations in each state to implement a program that would allow for Kansas to receive benefit from the zero carbon emissions associated with future wind energy development.

6. While the deadline in the final rule for submission of a final state plan has been extended, the timeframe allowed is still substantially shorter than the time period required to develop the state regional haze plans for EPA's Regional Haze Rule. Therefore, the State could not wait until the Rule was finalized to begin evaluating the Section 111(d) Rule and has therefore expended substantial resources to create a State 111(d) Plan. This expenditure of resources has included significant staff time to date and has expanded significantly as we are moving forward in reviewing the final rule to determine its implications for Kansas. Our activities include evaluating the data and underlying assumptions used in calculating the goal to ensure they are correct; educating the regulated entities and other stakeholders regarding provisions of the final Rule; coordinating with the Kansas Corporation Commission ("KCC") regarding modeling alternate dispatch scenarios to comply with the Rule; evaluating the change in Kansas law regarding implementing renewable energy standards and its impact on complying with the Rule; evaluating different compliance strategies that could be implemented to meet the goal in the final Rule; determining what statutory and regulatory changes will be needed for each of the strategies; and taking initial steps to develop support across all stakeholders and policy makers for potential compliance strategies. With the limitations described above regarding building block number one, implementation of a plan with sufficient renewable energy to meet the goal and offset the harm associated with stranded investments will require significant policy shifts by the Kansas legislature and other policymakers.

7. The State will expend significant resources as a direct result of the Section 111(d) Rule. This includes time to read, absorb, and interpret the several thousand pages of white papers, program design documents, preamble, rule and technical support documents, as well as to attend meetings and conference calls with stakeholders, elected officials and the KCC. The State expects to take further steps in the coming months as a direct result of the Section 111(d) Rule. Kansas will likely need statutory and regulatory changes, all requiring considerable staff time. Consultation meetings will include additional meetings with the KCC staff, the Southwest Power Pool, the Kansas Municipal Utilities, and the Kansas Power Pool. KDHE staff will present legislative briefings once the Kansas Legislature is in session. A considerable amount of staff effort will be needed to educate stakeholders and develop a plan. KDHE expects to spend the equivalent of at least four full-time employee positions per year amongst the six to eight staff and managers who are involved in implementing the final Rule (including proposing a state plan) for the next several years.

8. If a stay is entered by this Court, Kansas will halt the above-described expenditures.

9. Absent a stay from this Court, it is not practical for Kansas to wait to continue work on its State 111(d) Plan. It is already doubtful that Kansas can design a Plan in time to comply with EPA's deadlines. Waiting until litigation concludes will make compliance with EPA's deadlines impossible. And any delay in designing a State Plan will risk Kansas's ability to comply with EPA's deadlines. The timeframes available to states are insufficient to allow compliance with the Rule.

10. Absent a stay from this Court, if Kansas chooses to adopt a multi-state approach to complying with the Section 111(d) Rule, Kansas may need to enter into either a memorandum

of understanding or agreement with the other states. Kansas has limited experience in pursuing this type of agreement with other states, and anticipates that a significant amount of time would be required to negotiate and reach consensus on the content of such an agreement with other state agencies.

11. Absent a stay from this Court, implementation of the Section 111(d) Rule will require legislative changes, which will require the substantial expenditure of State resources that must be spent in the next year, and consideration of which must begin immediately. Undertaking these measures will seriously disrupt the State's sovereign priorities, which would otherwise be devoted to addressing other pressing issues of public concern.

12. Since the finalization of the Section 111(d) Rule, my staff and I have spent hundreds of hours on the following: reading the rule, discussing the rule with EPA in various conference calls; discussing the rule with KDHE management; discussing with and explaining the rule to stakeholders, including Kansas' electric generators; going before a joint committee of the Kansas Legislature in an all-day session to provide agency comment and receive feedback; and more. This has diverted my and my staff's attention away from other matters that we would normally be addressing.

I declare under penalty of perjury that the foregoing is correct. Executed on this _______ day of October 14, 2015, at Topeka, Kansas.

Thomas Gross

Thomas Gross

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

STATE OF WEST VIRGINIA, STATE OF TEXAS, et al Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, and REGINA MCCARTHY, Administrator, United States Environmental Protection Agency, Respondents	CASE no. ____________________

DECLARATION OF SOUTH DAKOTA
DEPARTMENT OF ENVIRONMENT AND NATURAL RESOURCES

I, Brian Gustafson, declare as follows:

1. I am the Engineering Manager III for the Air Quality Program at the South Dakota Department of Environment and Natural Resources ("SD DENR"). I have been employed at this position for nearly 15 years. As part of my duties, I am responsible for the development, administration and enforcement of South Dakota's Air Quality Program. I have personal knowledge and experience to

understand what steps that South Dakota has taken and will need to undertake in response to the United States' Environmental Protection Agency ("EPA") final Section 111(d) Clean Power Plan Rule, hereinafter, referred to as Section 111(d) Rule.

2. South Dakota is a rural state covering approximately 77,000 square miles which is in attainment with all of the federal National Ambient Air Quality Standards. I oversee 14 individuals in the implementation of South Dakota's Air Quality Program with the goal of maintaining our attainment status.

3. South Dakota has received delegation or approval of the following federal air programs from the EPA: South Dakota's State Implementation Plan (minor air quality construction permit program, minor air quality operating permit program, Prevention of Significant Deterioration preconstruction permit program, New Source Review preconstruction permit program, Rapid City area fugitive sanding and construction activity program, ambient air monitoring network, and regional haze program), New Source Performance Standards, National Emission Standards for Hazardous Air Pollutants, Title V air quality operating permit program, and the Acid Rain program.

4. I have been involved in the revision and/or development of these delegated or approved regulatory programs, including the development of

necessary legislation, drafting and presentation of rules, and administration and enforcement of the programs.

5. I have also been involved in the development and implementation of South Dakota's 111(d) State Plan for existing Municipal Solid Waste Landfills.

6. Based on my experience, I have determined that implementing the Section 111(d) Rule will be a complicated and time-consuming endeavor. The Section 111(d) Rule is unlike any other Clean Air Act implementation undertaken by South Dakota. Specifically, the Section 111(d) Rule's reliance on the reduction of demand from a particular source of energy—Building Blocks 2 and 3—in determining Best System of Emission Reductions for Electric Generating Units is entirely unprecedented and will require the use of these outside the fence line measures to comply with South Dakota's final goal. Since EPA established the Best System of Emission Reductions on outside the fence line measures and not demonstrated air pollution control technology available to the utilities, South Dakota will be required to expend an unprecedentedly large number of resources to design a State Plan that incorporates these building blocks and still provide affordable and reliable electricity to South Dakota's constituents.

7. Already, two employees have expended hundreds of hours to understand and comment on the proposed Section 111(d) Rule and met with multi

state organizations on multiple occasions to determine the best way(s) to comply with the proposed Section 111(d) Rule. This does not include the amount of time employees of South Dakota's Public Utilities Commission and other state agencies have spent reviewing and commenting on the proposed 111(d) Rule or the amount of time the electrical industry and the public spent reviewing and commenting on the proposed 111(d) Rule.

8. In EPA's final Section 111(d) Rule, EPA specifies that each state must adequately demonstrate it has sufficient funding to implement the 111(d) State Plan. EPA did not provide any additional funding to support a 111(d) State Plan. South Dakota will have to reprioritize its limited financial resources in order to develop and implement the 111(d) State Plan.

9. In EPA's final Section 111(d) Rule, EPA revamped how each state's goal was calculated and the methods in which to comply with the final state goal. Because the final Section 111(d) Rule has drastically changed from the proposal, I estimate it will take a minimum of two employees in the Air Quality Program hundreds of hours to review and understand EPA's final Section 111(d) Rule.

10. In addition, a minimum of two employees in the Air Quality Program will each expend approximately half their time preparing enough of a 111(d) State Plan to qualify for EPA's two year extension by the September 2016 deadline. A

minimum of two employees will each expend approximately half their time preparing the final 111(d) State Plan by the September 2018 deadline.

11. Based on the complexity of the Section 111(d) Rule, the involvement of South Dakota's Public Utilities Commission and other state agencies, the potential enactment of new state legislation necessary to implement the 111(d) State Plan, and development of new administrative rules necessary for an approvable 111(d) State Plan, SD DENR will need EPA's 2 year extension to complete the 111(d) State Plan.

12. Using essentially one full time employee out of 15 employees within South Dakota's Air Quality Program and using limited financial resources to develop the 111(d) State Plan will hamper South Dakota's ability to conduct its other duties. This does not include the amount of time employees of the South Dakota's Public Utilities Commission and other state agencies will spend on ensuring the 111(d) State Plan provides affordable and reliable electricity to South Dakotan's or the amount of time the electrical industry, the public, and environmental groups will spend in working with SD DENR on the development of the 111(d) State Plan.

13. Absent a stay from this Court, planning and compliance for the Section 111(d) Rule, including designing a 111(d) State Plan, will require an

unprecedented amount of SD DENR's resources, which expenditure will begin immediately. In addition, waiting until the litigation concludes will make compliance with EPA's deadlines impractical. Any delay in designing a 111(d) State Plan will risk South Dakota's ability to comply with EPA's deadlines.

14. If South Dakota chooses to adopt a multi-state approach to comply with the Section 111(d) Rule, South Dakota may need to enter into either a memorandum of understanding or agreement with the other states. South Dakota has limited experience in pursuing this type of agreement with other states, and anticipates that a significant amount of time and financial resources would be required to negotiate and reach consensus on the content of such an agreement with other state agencies.

15. Depending on the complexity of the 111(d) State Plan, implementation of the Section 111(d) Rule may require legislative changes, which will require the substantial expenditure of South Dakota resources that must be spent in the next three years, and consideration of which must begin immediately. In order to submit an EPA approvable 111(d) State Plan, SD DENR must have the ability to enforce each portion of the 111(d) State Plan, some of which SD DENR does not currently have the authority to enforce. In order to have the ability to enforce in-state components of the plan, such as renewable portfolio standards,

energy efficiency, etc., the South Dakota legislature will have to re-write state law to provide the SD DENR that authority.

16. The Section 111(d) Rule establishes the Best System of Emission Reduction for Electric Generating Units on three "Building Blocks", which will require South Dakota to use at least those three building blocks to meet the state's goal. Of these three "Building Blocks", only one is directly in the regulatory control of SD DENR's Air Quality Program: Block 1, Efficiency Improvements at Affected Coal-Fired Steam Electric Generating Units. The Air Quality Program has direct regulatory control over such emissions through its Air Quality Permitting programs.

17. Building Block 2 involves the shifting of energy produced from coal-fired power plants to natural gas-fired combined cycle power plants. South Dakota has one coal-fired power plant and one natural gas-fired power plant. These two power plants are not owned by the same entities, do not have common regional transmission operators, and do not have common customer bases. As a result, this alteration may result in some customers of the coal-fired power plant being without a power source. It is my understanding that the state (including the South Dakota Public Utilities Commission) does not have regulatory authority to order a coal-fired power plant to cut its production; or to order the natural-gas fired power plant

to increase its production rate. As a result, utilization of Building Block 2 may not be an option which will require SD DENR to develop other alternatives to achieve EPA's goal for South Dakota some of which may require new state legislation.

18. Building Block 3 requires the shifting of energy from fossil-fuel fired plants to renewable energy sources; in 2012, South Dakota's wind energy was 24% of its power generation and none of this renewable energy is recognized by the final Section 111(d) Rule. South Dakota must determine how to further encourage private businesses to develop wind resources in an area that has already been developed. This may require new state legislation.

19. These changes required in the final Section 111(d) Rule involve the very fundamentals of power supply and development within the State and concern matters that have traditionally been determined not by state government, but by the marketplace. Thus, much of requirements required in the 111(d) State Plan involve major fundamental changes and will potentially be a matter of significant debate before the South Dakota Legislature.

20. Undertaking these measures will seriously disrupt the State's sovereign priorities, which would otherwise be devoted to addressing other pressing issues of public concern. Importantly, the above-described measures may also involve changes in South Dakota's law, which will then need to be undone if

the Section 111(d) Rule is invalidated. Again, this would seriously disrupt the State's ability to achieve its own sovereign priorities.

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

Dated this 13 day of October, 2015.

Brian Gustafson

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

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ______

DECLARATION OF KAREN HAYS

STATE OF GEORGIA
COUNTY OF CLAYTON

I, Karen Hays, hereby declare as follows:

1. I am Chief of the Air Protection Branch (APB) of the Georgia Environmental Protection Division (GA EPD). I have been employed by GA EPD for 17 years, holding a number of positions in the APB. As a part of my duties as Chief, I am responsible for overseeing GA EPD's preparation and implementation of state plans to comply with requirements of the federal Clean Air Act (CAA) and the air quality regulations promulgated pursuant thereto by the United States Environmental Protection Agency (EPA).

2. Based on my experience, I have the personal knowledge of and understand the many steps the State will need to undertake in response to EPA's final rule, *Carbon Pollution Emission Guidelines for Existing Stationary sources: Electric Utility Generating Units,* ("111(d) Rule" or "Rule"), including preparing a state plan to implement this Rule. Based on my review of the final Rule, I have determined that development and implementation of the state plan to implement the 111(d) Rule will be the most complex and time consuming rulemaking ever undertaken by GA EPD. The challenge is made even more complicated by the substantial changes in the 111(d) Rule between the proposed and final Rule, and the Rule's unprecedented reliance on control measures that extend beyond the affected fossil fuel-fired electric generating units

3. The utilities that provide electricity in Georgia include: (a) Georgia Power, an investor-owned utility; (b) Oglethorpe Power, owned by 38 electric membership cooperatives (EMCs); (c) the Municipal Electric Authority of Georgia (MEAG), a public power entity created by an Act of the Georgia General Assembly in 1975 that represents 49 municipal utilities; (d) Dalton Utilities and (e) several independent power producers. Additionally, ten counties in north Georgia are served or partially served by the Tennessee Valley Authority (TVA). Georgia Power is regulated by the Georgia Public Service Commission (PSC). The PSC has limited regulatory authority over the EMCs and municipal utilities in the state. There is no single regulatory entity that determines how electricity is generated and distributed in Georgia, which makes developing a state plan applying to all Georgia utilities extremely challenging.

4. The 111(d) Rule is structured to encourage increased reliance on renewable energy sources of electricity in order to achieve significant reductions in carbon dioxide emissions from fossil fuel-fired electric generating units. This has the potential to disproportionally impact smaller utilities in Georgia. Small utilities that serve small municipalities or rural communities may be left with stranded coal assets at the same time that they are required to invest in additional renewable energy capacity. These additional costs will be borne by their small base of rate payers and impede economic development in these areas. Developing a state plan that does not disproportionately impact small communities served by small utilities will be extremely challenging.

5. EPD does not have the regulatory authority to: 1) set state energy policy; 2) require utilities or other entities to use natural gas instead of coal to generate electricity; or 3) require utilities to obtain electricity from renewable energy sources. Action by Georgia's state legislature and other state regulatory entities may be required to fully implement the Rule. Absent a stay from this Court, evaluation of potential legislative changes to statutes GA EPD is unfamiliar with, since we are not typically governed by them, would be very resource intensive. Likewise, coordination with state regulatory entities that GA EPD does not normally work with, and therefore does not have established relationships or an understanding of their existing rules and processes, will take significantly more time than normal Air Quality Rule revisions do in order for GA EPD to meet the state plan submittal deadlines of this Rule.

6. The resources necessary to develop and implement the Rule are unprecedented. Approximately 20 GA EPD staff members are involved in analyzing various aspects of the Rule, expending over 5,000 hours on this effort to date. This work includes but is not limited to understanding the building blocks that constitute EPA's determination of "Best System of Emission Reduction", and participating in conferences, seminars and meetings with EPA, utilities, Georgia Public Service Commission staff, state energy office staff, EMCs, air agency staff from other states, university experts, non-governmental organizations, and other stakeholders. Such an extensive time commitment has been necessary for GA EPD staff to gain even a basic understanding of the Rule and the energy infrastructure. GA EPD staff are in the position of developing a state plan that will have long lasting and profound effects on the energy infrastructure and ultimately what Georgia citizens pay for electricity. Given the sweeping nature of this rule relative to all previous air rules and the significant impact implementation may have on Georgia ratepayers and the state's overall economic competitiveness, GA EPD will be required to devote even more resources to fully understand the final rule, assess the multiple compliance pathways to determine the least costly course, and ultimately develop a state plan. This effort is diverting GA EPD resources from work on other Clean Air Act requirements.

7. Absent a stay from this Court, GA EPD must immediately begin work on developing a state plan due to the complexity of the Rule. 40 CFR 60.5760 and 40 CFR 60.5765 of the Rule require an initial state plan to include a demonstration that the state has evaluated multiple state plan approaches and a demonstration of meaningful engagement with stakeholders, including vulnerable communities. Even a cursory evaluation of multiple approaches and a minimal effort for "meaningful" stakeholder engagement will make preparing and submitting an initial state plan by September 2016 extremely challenging.

8. Absent a stay from this Court, GA EPD will need to request an extension until September 2018 for submittal of a final state plan to EPA. The time required to collect stakeholder input, analyze alternatives and design a workable state plan is much greater for this Rule than for other state air quality rules due to the complex nature of the issues and the necessity to coordinate with other state entities with authority and expertise in energy policy and regulation. The state plan will likely require revisions of the Georgia Rules for Air Quality Control. Revisions of the Georgia Rules for Air Quality Control must be adopted by the Department of Natural Resources Board prior to submittal of the state plan to EPA. Completing all of this work within the prescribed timeframe, given all of the other Clean Air Act requirements already imposed upon GA EPD, will be very challenging.

9. Absent a stay from this Court, any potential changes to the Rule resulting from court decisions, which will most likely take several years to decide, will require additional analysis and modification of the state plan developed by GA EPD. Legislative action or actions by other state regulatory entities may be required to implement changes to the Rule. Additional revisions of the Georgia Rules for Air Quality Control may be required. This will result in significant additional costs and a further expenditure of limited state resources.

Executed under penalty of perjury this the 20 day of October, 2015.

Karen Hays

Karen Hays

This the 20 day of October, 2015.

LouAnn Carmichael

Signature of Notary Public

LOU ANN CARMICHAEL NOTARY EXPIRES GEORGIA SEPT 1st, 2019 PUBLIC SPALDING COUNTY GA

Lou Ann Carmichael

Print or Type Name of Notary Public

My commissions expires: 09/01/2019

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

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ________

DECLARATION OF ROBERT HODANBOSI, CHIEF, DIVISION OF AIR POLLUTION CONTROL, OHIO ENVIRONMENTAL PROTECTION AGENCY

I, Robert Hodanbosi, declare as follows:

1. I am the Chief of the Division of Air Pollution Control at the Ohio Environmental Protection Agency ("Ohio EPA"). I have served as Chief of the Division for over 22 years and have been a member of the Division of Air Pollution Control at Ohio EPA for over 40 years. As part of my duties, I am responsible for all aspects of Ohio's air pollution control program—compliance

monitoring, permit issuance, regulatory enforcement, and administering for Ohio the delegated aspects of the federal program under the Clean Air Act, as well as Ohio's own air pollution control laws and rules. Among my duties are attainment/nonattainment planning, SIP calls, state implementation plan development, regulation development, and other matters as necessary. In this capacity, I am familiar with Ohio's electric generating units, their generating capacity, and the regulatory and related issues they face, as well as other industrial and commercial sources of air pollution. It will be my and my staff's responsibility to undertake and implement Ohio's response to the U.S. EPA's Section 111(d) Rule.

2. Based on my experience, I have determined that implementing the Section 111(d) Rule will be a complicated and time-consuming endeavor. The Section 111(d) Rule is unlike any other Clean Air Act implementation undertaken by Ohio. Among other things, the Section 111(d) Rule's reliance on measures that require the reduction of demand for a particular source of energy—the substitution of certain types of energy for others in building blocks 2 and 3—are entirely unprecedented for Ohio. The State would be required to expend an unprecedentedly large number of resources to design a State Plan that incorporates these building blocks. The burden on the State in doing so is further aggravated by the substantial changes between the proposed and final rules. The State's

resources would have to be diverted from work on the State's other air pollution activities. See Appendix A.

3. Already, various employees have expended approximately 3000 hours seeking to understand the Section 111(d) Rule and preparing for its potential implementation. This has included reviewing the proposed and final rules, attending webinars held by U.S. EPA, and participating in stakeholder meetings, among other endeavors.

4. Given the complexity of the issues involved and the comprehensive nature of the unprecedented regulatory program, it would not be practical for Ohio to postpone work on a State Plan absent a stay from this Court. It is not proper to expect that Ohio can design an effective interim State Plan in time to comply with U.S. EPA's deadline, which is now September 2016. Waiting to attempt implementation until after the litigation concludes while still complying with U.S. EPA's 2016 deadline would not be feasible.

5. In addition, it is uncertain whether any State Plan will be approved by U.S. EPA and implemented in time for regulated parties to comply with the Section 111(d) Rule's interim goals, making any delay in expending resources impractical. Waiting until litigation on this unprecedented rulemaking is complete to begin work on a State Plan would make it impossible for Ohio to meet the Section 111(d) Rule's interim compliance goals and U.S. EPA's deadline. Ohio

must now determine and evaluate the mechanisms needed to comply with the rule. This will include an evaluation of any necessary legislative changes to the Ohio Revised Code. It also remains uncertain whether Ohio EPA or any other state agency has authority or jurisdiction to demand an out-of-state entity such as PJM (the electric grid manager for Ohio) to modify their current practice of determining which plants to operate and supply power to the grid that supplies electricity for Ohio citizens and businesses.

6. Absent a stay from this Court, planning and compliance for the Section 111(d) Rule, including designing a State Plan, would require an enormous ongoing amount of human resources. Preparing and submitting a timely plan would require various dedicated Ohio EPA staff members, as well as significant resources from other state agencies, stakeholders, and potentially the legislature. As the new 40 C.F.R. § 60.5760 and 40 C.F.R § 60.5765 make clear, any possible extension from the September 6, 2016, deadline would require Ohio to provide a submittal that identifies and describes the final plan approach under consideration and the opportunity that Ohio provided for comment from relevant stakeholders on this approach.

7. Absent a stay from this Court, if Ohio endeavors to adopt a multi-state approach to comply with the Section 111(d) Rule, Ohio would need to enter into either a memorandum of understanding or agreement with the other states. Ohio

has limited experience in pursuing this type of agreement with other states under the Clean Air Act, and anticipates that a significant amount of time would be required to negotiate and reach consensus on the content of such an agreement with other state agencies such that the final agreement meets U.S. EPA approval.

8. Absent a stay from this Court, implementation of the Section 111(d) Rule could require legislative changes, which are uncertain and would require the substantial expenditure of Ohio resources that must be spent in the next year. Consideration of which legislative changes might be necessary must begin immediately. The Section 111(d) Rule could require a sweeping change to the Ohio EPA's authority beyond any other previous requirements under the Clean Air Act.

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

Executed on August 11, 2015 Robert Hodanbosi

Appendix A
Upcoming Clean Air Act State Implementation Plan Activities

1. Sulfur dioxide Consent Decree designations for certain unclassifiable area sources.
    a. Required under March 2, 2015 Northern district of California, enforceable agreement order between EPA and Sierra Club/NRDC.
    b. In a May 20, 2015 letter to the Governor, U.S. EPA provided a schedule for completing designations for these areas around these sources. The letter provides it as an option for States to submit recommendations, but CAA Section 107(d)(1)(A) requires governors to submit initial designations. Ohio has yet to submit designations for these areas.
    c. State recommendations are due September 18, 2015.

2. Remaining sulfur dioxide unclassifiable area source designations.
    a. Required under 79 FR 27446 – Proposed Data Requirements Rule and May 20, 2015 Memo (Stephen Page to Regional Air Division Directors, "Updated Guidance for Area Designations for the 2010 Primary Sulfur Dioxide National Ambient Air Quality Standards").
    b. Schedule and process for designating unclassifiable areas.
        i. January 1, 2016: provide lists of sources to be modeled or monitored.
        ii. July 1, 2016: Submit monitoring plan for monitored sources.
        iii. January 1, 2017: Begin operation of monitors.
        iv. January 13, 2017: Submit modeling analysis and recommended designations for modeled sources.
        v. December 2017: USEPA will finalize designations with additional input from States during the 120-day letter notification.
        vi. August 2019: Attainment demonstrations due for modeled areas.
        vii. Mid 2020: Designations for monitored areas. States will be required to provide recommendations prior to this.
        viii. August 2022: Attainment demonstrations due for monitored areas.

3. Completion of sulfur dioxide attainment demonstration and revisions to federally enforceable regulations.
    a. Due April 4, 2015 but was delayed due to significant resource allocation during Clean Power Plan proposal. Submittal by October 4, 2015 necessary or Ohio's submittal can be found incomplete and a Federal Implementation Plan clock can be initiated.

4. Particulate Matter (PM2.5) infrastructure SIP for the 2012 PM2.5 standard.
    a. Required under CAA Section 110(a)(1)
    b. Due December 13, 2015

5. PM2.5 attainment demonstration for the 2012 PM2.5 standard.
    a. Required under CAA Section 110(a)(1) and Section 189.
    b. Due October 15, 2016

6. Redesignation and maintenance plans for two areas under the 2008 ozone standard
    a. Requirements contained in CAA Section 107(d)(3)(E)
    b. Areas should be redesignations as soon as practicable after attaining the standard. These areas attained at the end of 2014. Typically takes 6-9 months to prepare a redesignation request for submittal that fulfills the CAA requirements.

7. Redesignation and maintenance plan or extension request for one remaining area under the 2008 ozone standard.
    a. If this area attains at the end of the 2015 calendar year, a redesignation request will need prepared (see item 6 above), or if the area qualifies, an additional extension request will need prepared. If the area does not qualify, more extensive attainment planning may be necessitated.

8. Redesignation and maintenance plans for two areas under the 2008 lead standard.
    a. Requirements contained in CAA Section 107(d)(3)(E)
    b. Areas should be redesignations as soon as practicable after attaining the standard. These areas attained at the end of 2014. Typically takes 6-9 months to prepare a redesignation request for submittal that fulfills the CAA requirements.

9. 2015 ozone standard.
    a. Designations required under CAA Section 107(d)(1)(A) and attainment plans required under Section 110(a)(1) and Section 182.
    b. Projected to be finalized in October 2015. State recommendations on nonattainment will be due within 1 year. Designations complete within the following year. And state attainment plans would be due within 2 years of designations.

10. Transport SIPs for 2008 ozone standard.
    a. Required under CAA Section 110(a)(1) and Section 110(a)(2).
    b. Notice of Data Availability signed on July 23, 2015. States must submit comments by September 23, 2015.
    c. Transport SIP requirements expected to be proposed in 2015. States will need to prepare comments on the proposal and then be required to prepare SIPs to address requirements in this rule once final.

11. Appendix W comments.

a. On July 14, 2015, the Administrator signed a proposal to revise the *Guideline on Air Quality Models*. (Appendix W)
b. States must submit comments by October 27, 2015.

12. Corrections to older 2008 infrastructure SIPs.
    a. Infrastructure SIPs are required under CAA Section 110(a)(1). On May 15, 2015, EPA entered into a consent decree with Sierra Club requiring certain elements of these SIPs be addressed by March 31 and August 31, 2015 and also June 7, 2016. States must prepare submittals to address these elements and provide those to USEPA in time for them to act on these submittals by the consent decree deadlines.

13. Regional Haze 5-year review analysis.
    a. Required under CAA Section 169 and the Regional Haze Rule (64 FRCAA Section 169 and the Regional Haze Rule (64 FR 35714).
    b. Due by March 11, 2016.

14. NOx SIP Call/CAIR non-EGU/CSAPR Corrections.
    a. U.S. EPA's new Cross State Air Pollution Rule (CSAPR) applied to different sources than were covered under both the NOx SIP Call requirements and the Clean Air Interstate Rule (CAIR). States are required to address this discrepancy since U.S. EPA no longer administers the programs that applied to the sources no longer covered under CSAPR.

15. Startup, Shutdown, and Malfunction SIP Call

    a. On June 12, 2015 (80 FR 33840), U.S. EPA issued a SIP Call that requires Ohio to revise rules on emissions from startup, shutdown, malfunction and scheduled maintenance
    b. Revised rules to U.S. EPA are due within 18 months.

16. Cincinnati Area PM2.5 RACT/RACM Study

    a. As a result of the recent U.S. Sixth Circuit Court of Appeals July 14, 2015 decision to stay the Cincinnati area redesignation of the 1997 PM2.5 standard, Ohio will need to prepare a study of Reasonable Available Control Technology/Reasonably Available Control Measures (RACT/RACM).

    b. The RACT/RACM study requires that Ohio EPA examine all major sources of PM2.5 and determine if the control of the sources are RACT/RACM. An additional redesignation request will have to be submitted with the RACT/RACM analysis.

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

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. _____

DECLARATION OF RICHARD A. HYDE, P.E., EXECUTIVE DIRECTOR, TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

I, Richard A. Hyde, P.E., declare as follows:

1. I am the Executive Director of the Texas Commission on Environmental Quality ("TCEQ" or "agency"), a position I have held since January, 2014.

2. The TCEQ is one of the largest environmental agencies in the United States. My agency has primary authority for implementing and enforcing air quality planning and permitting, water quality, water supply, water availability, remediation, municipal solid waste, radioactive waste, and hazardous waste programs in the State of Texas. TCEQ has approval to administer every major federal environmental program in Texas.

3. In Texas, Executive Agencies under the direction of the Governor have responsibility to implement their specific legislative directives. The TCEQ is the Executive Agency in the state of Texas with responsibility for air quality, including the submittal of state plans to the United States Environmental Protection Agency ("EPA"). The Public Utility Commission of Texas ("PUCT") is the Executive Agency responsible for ensuring the provision of reliable, low cost electricity to consumers.

4. As Executive Director, I am the Agency's chief executive, reporting to the Governor-appointed Commissioners.

5. Among my responsibilities are recommending to the Commission any revisions to the state implementation plan ("SIP") required under §110 of the federal Clean Air Act ("FCAA") in order to demonstrate attainment and maintenance of the federally promulgated National Ambient Air Quality Standards ("NAAQS") and to protect visibility. I am also responsible for directing the enforcement of new source performance standards ("NSPS") adopted under §111(b) and for overseeing the development of state plans as required by §111(d) of the federal Act. I have followed EPA's proposed and final rules to implement §§111(b) and (d) as applied to carbon dioxide emissions ("CO_2") from new and existing electric generating units ("EGUs"), respectively. I also supervised staff that developed TCEQ's detailed comments on those rules as proposed. Accordingly, I have personal knowledge and experience to understand what steps the State of Texas has taken and would need to take in developing its response to the final rules for existing EGUs, titled, "Carbon Pollution

Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" rule (the "Rule"), as signed by the EPA Administrator and published on the EPA website on August 3, 2015. These steps include providing commission and legislative briefings on the Rule requirements, consulting with other state agencies, providing draft legislation and further legislative support if requested, and developing rules as necessary.

6. My opinions in this declaration have been informed by briefings from the TCEQ professional engineering, legal, and technical staff, in addition to meetings with other stakeholders concerning the proposed and final Rule, and discussions with the TCEQ commissioners. I believe that the opinions and statements offered herein are consistent with the opinions and statements of the Commissioners, Dr. Bryan Shaw, P.E., Mr. Toby Baker, and Mr. Jon Niermann.

Summary

7. The Rule establishes stringent limits on CO_2 emissions from fossil fuel-fired existing electric utility steam generating units and stationary combustion turbines, referred to in this declaration as either "boilers" and "turbines," "affected units," or "EGUs" generally. Because TCEQ is not aware of any proven, existing technology that will permit existing EGUs to meet these emission limits, it is my understanding that the ways in which electricity is generated, transmitted, and consumed in Texas will need to change.

8. The Rule requires that Texas file a State Plan (or participate in a multi-state plan) or be subject to a yet to be finalized Federal Plan. Any State Plan submittal

will require unprecedented coordination between the TCEQ, the Governor of Texas, the PUCT, the entities with responsibilities concerning electric generation, transmission, and distribution within Texas (Electric Reliability Council of Texas ("ERCOT"), Southwest Power Pool ("SPP"), the Midcontinent Independent System Operator ("MISO"), and the Western Electricity Coordinating Council ("WECC")), the State Energy Conservation Office ("SECO"), the Railroad Commission of Texas ("RRC"), lawmakers, and stakeholders, including owners and operators of affected units, local government officials and the public. Any State Plan developed through this coordinated effort would then be submitted by the Governor of Texas or his designee to the EPA.

9. The Rule requires that a State Plan be filed by September 6, 2016, less than one year from final publication of the Rule. Though the Rule does provide for up to a two year extension for the submittal of a final State Plan, the application for an extension is still due on September 6, 2016 and requires significant work and decisions that must still be made by the state. Regardless of whether Texas plans to submit its State Plan or ask for an extension, TCEQ, and other State agencies, must begin planning how to comply with the Rule immediately.

10. The possibility of a federal plan does not relieve the pressure on Texas to develop a State Plan. EPA's proposed rule for a Federal Plan (which would be effective if the State does not submit its own plan that is approved by EPA) is only in the comment stage and will not be finalized any sooner than Summer 2016. ("Federal Plan

Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or before January 8, 2014, Model Trading Rules; Amendments to Framework Regulations") ("proposed Federal Plan"), as signed by the EPA Administrator and published on the EPA website on August 3, 2015.) Because Texas does not know what the final Federal Plan will require, and cannot properly evaluate its effects, Texas must begin working on a potential State Plan immediately.

11. Therefore, the Rule is placing an immediate, significant resource burden on the TCEQ. Among other things, the Rule requires the agency, in coordination with the PUCT and other state agencies, to make immediate, fundamental decisions about Texas's environmental and energy policy within a year, with repercussions that could affect Texas's citizens, government, and economy for decades to come. The Rule requires the TCEQ and other state agencies to devote myriad staff to consider, formulate, and implement a State Plan, if the state chooses not to accept the Federal Plan.

Background about the Rule

12. The Rule establishes stringent limits on CO_2 emissions from *existing* EGUs. These limits are expressed as "performance rates" in Table 1 of the Rule. The limits for boilers also apply to integrated gasification combined cycle ("IGCC") units, which gasify coal to "syngas," and then burn that syngas in a conventional combustion turbine, although there are no such units operating in Texas; in fact, there are only a few around the U.S., all in the demonstration stage. The limits for existing stationary

combustion turbines apply to natural gas combined cycle ("NGCC") turbines and combined heat and power combustion turbines; simple cycle combustion turbines are exempt from the final rule.

13. The Table 1 performance rates are expressed as pounds of CO_2 per net megawatt-hour, or "lb/MWh." EPA imposed two limits for each of the two source categories, with an interim to be phased in over 2022 – 2029 and the final by 2030. The interim and final rates for boilers (and IGCC) are 1534 and 1305 lb/MWh, respectively. The corresponding interim and final limits for turbines are 832 and 771 lb/MWh, respectively. Because these are rates of emissions expressed as lb/MWh, if the rates are applied to an individual EGU, that EGU cannot merely run less often to meet the standard.

14. It is noteworthy that under the Rule, CO_2 emission performance rates for *existing* EGUs (boilers and stationary combustion turbines) are *more stringent* than the emission performance standards adopted by the EPA for *new or reconstructed* units of the exact same type. This is contrary to how EPA has implemented §111(d) in the past.

15. As a practical matter these standards are not achievable at any individual existing EGU through the traditional application of retrofit control technology considering technological and economic feasibility. I have come to this conclusion by consideration of several factors, including (a) consultation with other engineering experts on my staff, who regularly review the performance capabilities of power plants for purposes of undertaking best available control technology analyses in support of

the agency's permitting functions; and (b) EPA's establishment of a NSPS that sets emission rates significantly higher than those listed in Table 1 for existing sources.

16. In the absence of a practical retrofit control technology option, the only option remaining for the State of Texas to meet either the individual emission performance rates or the optional statewide goals is through requiring shifts in electricity generation—the same means assumed by the EPA in establishing those limits—likely also coupled with some form of emissions- or generation-based trading program.

17. EPA established its emission standard under the Rule not by using the traditional method of examining the best system of emission reductions "(BSER") that can be applied to each EGU as contemplated by Section 111, but rather established emission performance rates for existing units based largely on EPA's projections of shifting generation from steam generating units to natural gas combined cycle units and increased renewable energy generation—effectively defining BSER as the electric grid as a whole. It has been the TCEQ's understanding that BSER is supposed to be technology based, with due consideration of cost and other factors, when setting the emission rates under Section 111. Moreover, it has been the TCEQ's understanding that under Section 111(d), the states set the standards for sources within their jurisdiction, with EPA's role to issue emission guidelines for states.

18. The Rule includes alternative compliance options, expressed as separate and individualized mass-based or rate-based goals for each state. EPA derived these

goals by applying the performance rates in Table 1 to the generating mix of the affected units in each state. Table 2 of the Rule expresses these goals as pounds per net MWh, and Table 3 expresses them as total tons.

19. Because no EGU can practically meet the Rule's emission performance rate established in Table 1 (regardless of whether a State Plan or the proposed Federal Plan is utilized), the only way to meet these emission levels will be to reorganize the state's electric grid by reducing generation from certain facilities, increasing generation from others, and investing in and constructing new generation facilities. But this will likely not be achievable without also implementing an emissions- or generation-based trading system.

Absent a Stay, the Rule Will Cause Texas to Forfeit Sovereignty Over its Environmental and Energy Regulatory Programs.

20. In order to make an informed decision about whether to file a State Plan or submit to the yet to be finalized Federal Plan, the TCEQ and other state agencies, such as PUCT, must begin allocating, time, effort and resources to determine how to comply with the Rule. This due diligence work must begin immediately.

21. The Rule allows the Governor of Texas only until September 6, 2016, to submit Texas's State Plan. EPA may grant states a 2-year extension provided the requesting state explains why it needs more time, identifies the final plan options it is considering and progress made to date, and it has planned for and engaged with stakeholders, including "vulnerable communities," in the preparation of the initial and

final plans. In practice, however, Texas has less than one year to make the critical decisions that will dramatically affect its citizens, government, and economy for decades to come.

22. A threshold decision Texas must make, first and foremost, is whether to submit a State Plan. Under the Rule, if Texas chooses to not submit a State Plan, EPA will impose a Federal Plan. Importantly, as of today, EPA has only issued a proposed Federal Plan, which will not be made final according to EPA until summer 2016. This means that Texas will have virtually no time to review the final Federal Plan to decide whether to accept EPA's Federal Plan or to begin developing, documenting, and adopting its own State Plan by the deadline for either a final plan or a request for extension (September 2016). This situation leaves Texas little choice but to begin allocating, time, effort and resources immediately.

23. Based on my knowledge and experience, the generation, transmission and reliability of electric power is not governed by the FCAA, but instead is governed by the Federal Power Act and the Federal Energy Policy Act of 2005, which reserve specific authority to states, instead of the federal government. While the TCEQ has authority for air, water and waste issues arising from the construction and operation of EGUs, the PUCT is the state agency in Texas that is responsible for ensuring the provision of reliable, low cost electricity to consumers.

24. As discussed above, since no proven, existing technology will allow an EGU to meet the emission levels established in the Rule, it is likely that electric

generation will have to be shut-down, curtailed and shifted to other resources. Moreover, it is likely that an emission-trading program will need to be developed in order to meet the statewide emissions levels. In fact, the proposed Federal Plan would implement such an emissions trading system. Under an emissions trading system, non-emitting renewable generation would produce emissions credits, which could presumably be used to offset fossil fuel generation, or sold to fossil fuel generators.

25. The TCEQ currently has no regulatory program or mechanism to inventory or track generation and/or CO_2 emissions, including for renewable sources that do not emit CO_2 or other pollutants. There also is no regulatory program to make allocations and/or assign and enforce emission limits for CO_2 in a manner that will comply with the Rule. It will require unprecedented coordination between the Governor of Texas, the TCEQ, the PUCT, the ERCOT, SPP, MISO, WECC, the SECO, the RRC, lawmakers, and stakeholders, including owners and operators of affected units and renewable energy sources, local government officials and the public.

26. Compliance with the Rule (or even the Federal Plan) will have to take into account the way Texas' electric market is structured. My understanding is that Texas has adopted a competitive generation system, in which the most cost-competitive (cheapest) source available at any time is the generator allowed to provide the power where and when needed. Because EPA has finalized emission performance rates that can only be achieved by prioritizing generation from sources that do not use fossil fuels, any Plan—whether State or federal—will require those who produce electricity using

fossil fuels to subsidize renewable generation to compete with it. Therefore, in order to achieve the final emission performance goals, Texas will be required to make fundamental changes in its energy policy to force shifts in the generation of electricity from coal-fired EGUs to NGCC and carbon-neutral generation resources.

27. Developing a State Plan will be complicated and will require the TCEQ, along with other agencies, to apply significant time, effort and resources. If Texas chooses to submit a State Plan, at a minimum, the State Plan will likely need to:

- Identify all EGUs and affected units;
- Impose (and demonstrate that) emission standards for each affected unit cumulatively will achieve the state emission goals;
- Provide a commitment to include corrective measures that will ensure compliance with state emission goals if necessary to achieve the emission goals;
- Establish appropriate triggers to ensure compliance;
- Establish schedules for compliance; identify all applicable monitoring, recordkeeping, and reporting requirements for each affected unit; set requirements for state reporting to EPA;
- Demonstrate that each affected unit's emission standard is quantifiable, non-duplicative, permanent, verifiable and enforceable; and
- Identify other specific requirements for rate-based, mass-based, or other state measures-based plans.

28. If the State wishes to or needs to establish rate-based standards on individual affected units different from those in Table 1 or the Texas specific limit in

Table 2 or the Rule, the Plan will also be required to include a projection of future CO_2 emission rates and information for each affected unit concerning:

- Annual generation;
- CO_2 emissions;
- Fuel use;
- Fuel prices;
- Fuel carbon content;
- Fixed and variable operations and maintenance costs;
- Heat rates;
- Electric generation capacity and capacity factors;
- Any planned new electric generating capacity;
- Potential for unplanned new electric generating capacity;
- Implementation timelines for EGU-specific actions;
- All wholesale electricity prices;
- Geographic representations appropriate for capturing impacts and/or changes to the electric system;
- Anticipated electricity demand forecasts at the state or regional level;
- Emission rate credit or emission allowance prices, if applicable;
- Identification of state-enforceable measures with electricity savings and renewable energy generation in MWh, expected for all individual and collective measures;

- Planning reserve margins; and
- Any other assumptions used in the demonstration to project that the emission goal will be achieved.

29. If the state decides to implement a rate-based program, then the state must create a new accreditation program for independent verifiers to review emission reduction credit ("ERC") applications and reports from eligible resources wanting to receive an ERC.

30. In short, a State Plan will need to identify and apply emission standards for all EGUs and affected units and create a program to implement and enforce those standards; and it must include a demonstration that the reliability of the electrical grid has been considered, which will require coordination with multiple entities due to Texas' unique grid structure. All of this will require immediate work, effort and use of resources by the TCEQ and other state agencies in order to develop a potential State Plan. And because the Federal Plan will not be finalized until 2016, the State of Texas cannot wait to start working on the potential State Plan.

Absent a Stay, Texas Must Begin Working Significant Statutory and Regulatory Changes.

31. As a practical matter, in light of the September 6, 2016 and September 6, 2018 deadlines established by the Rule, the TCEQ cannot wait until the litigation challenging the Rule is concluded to create and implement a State Plan.

32. EPA is proposing that Texas can and should regulate facilities in ways never before considered, contemplated, or authorized by the federal or Texas Clean Air Acts. Instead, because the Rule requires Texas to make policy choices about the manner in which electricity is generated, transmitted, and consumed, the State Plan necessarily will be a coordinated effort between the TCEQ and other state agencies and entities with responsibilities concerning electric generation, transmission, and distribution. Therefore, implementation of the Rule will likely require fundamental statutory and regulatory changes that will require the immediate, substantial expenditure of unrecoverable Texas resources.

33. The coordination made necessary by the Rule will likely require changes to the TCEQ's statutory authority to ensure that all required elements of the State Plan could be met in coordination with legislative direction for the TCEQ and other state agencies. The TCEQ, or some combination of state agencies, must have the legal authority to require the emission reductions necessary to meet the state emission performance goal, monitor compliance, enforce each component of the State Plan, and provide required reports to EPA.

34. The Texas Legislature meets on a biennial schedule. The next regular session of the Texas Legislature is scheduled for January through May 2017. While the Governor of Texas has authority under the Texas Constitution to call a special session, this will result in a significant nonrefundable cost to the State of Texas. There is no guarantee that one special session will successfully lead to an agreement to reorder

Texas's longstanding competitive market scheme for generation, especially with the very substantial prospect of the command to do so being undone on judicial review. Due to the complex policy and legal issues arising from the directives of the Rule, multiple or longer special sessions may be necessary.

35. Once the Texas Legislature and the Governor determine the manner in which the State of Texas would change its legal structure for electricity generation, transmission and related regulation, the TCEQ and other state agencies, such as the PUCT, would need to adopt rules, as well as adopt and implement a State Plan. It typically takes 12-24 months for a complex rule to be developed, proposed and adopted by the TCEQ, and additional time may be necessary for this rule given the additional requirements (such as the environmental justice assessment) and the potential for legislative changes. For complex rulemakings, senior staff from each TCEQ office participate as part of the rulemaking team to ensure that applicable federal and state requirements are met, as well as to ensure that potential implementation issues are addressed. Rulemaking team members are responsible for drafting preamble and rule language, preparing for and participating in public meetings, legislative support, reviewing and responding to public comment, and assuring that all administrative rule requirements of the Texas Administrative Procedures Act are met, such as required analysis regarding potential legal takings and major environmental rule analysis. In an attempt to remedy the economic and emission impacts to vulnerable communities created by the massive electric-generation shifts required by the Plan, EPA also requires

states to conduct a poorly defined environmental justice analysis. Because the requirement is so poorly defined, it is difficult to determine the possible resource burden with any certainty, but the Rule's preamble indicates that the analysis and outreach efforts would be extensive.

<u>Conclusion</u>

36. In conclusion, it is my opinion that implementing the Rule will require TCEQ and other state agencies to immediately invest time, effort and resources to develop a State Plan. In my experience, the Rule is unlike any other FCAA rule promulgated by the EPA that states must implement. It is truly unprecedented in both scope and complexity and will require Texas to change the way it regulates emissions and the generation of electricity. In order to submit a State Plan or even ask for an extension by September 6, 2016, TCEQ and other Texas agencies must begin work immediately. Because the Federal Plan is not yet finalized, Texas cannot wait to begin developing its potential State Plan. Developing a State Plan will require significant time, effort and resources and will likely require that existing laws and regulations of the State of Texas will need to be enacted, amended or modified. Texas will not be able to recover these costs.

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

38. Executed on 10-13, 2015.

Richard A. Hyde, P.E.

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

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ______

DECLARATION OF BRIAN H. LLOYD, EXECUTIVE DIRECTOR, PUBLIC UTILITY COMMISSION OF TEXAS

I, Brian H. Lloyd, declare as follows:

1. I am the Executive Director of the Public Utility Commission of Texas ("PUCT"). As Executive Director, I am responsible for the daily operations of the PUCT and the management of the PUCT's employees.

2. The PUCT is composed of three commissioners, appointed by the Governor, with the advice and consent of the Texas Senate, for staggered six-year terms. The commissioners are the policymaking part of the agency and issue final decisions on contested cases and rulemakings. The Executive Director is hired by the

commissioners and is responsible for the day to day operations and management of the agency.

3. As explained more fully herein, the PUCT is the principal regulatory authority over electricity markets in Texas. The PUCT's jurisdiction over electricity markets is outlined in the Texas Utilities Code. The PUCT's authority includes comprehensive regulation over the retail and wholesale electricity markets within the Electric Reliability Council of Texas ("ERCOT") and retail electric utilities in parts of the state outside of ERCOT.

4. I earned a Bachelor's of Arts Degree in economics at Louisiana State University and graduated from the University of Texas at Austin with a Master of Science in Economics Degree. I have extensive experience in both the electric and energy industries, and I have extensive experience testifying on electricity regulatory and policy issues before various Texas legislative committees, the Federal Energy Regulatory Commission ("FERC") and the PUCT.

5. As stated by the Environmental Protection Agency ("EPA"), the Rule "establishes final emission guidelines for states to follow in developing plans to reduce greenhouse gas ("GHG") emissions from existing fossil fuel-fired electric generating units ("EGUs"). Specifically, EPA is establishing: 1) carbon dioxide ("CO_2") emission performance rates representing the best system of emission reduction ("BSER") for two subcategories of existing fossil fuel-fired EGUs—fossil fuel-fired electric utility steam generating units and stationary combustion turbines." The term "EGU" is a

term used by EPA that is not defined in the Texas Utilities Code. Power plant owners and operators under Texas law as well as under the Federal Power Act ("FPA") are defined in various ways, depending on the context in which a particular term is used. For purposes of this declaration, I use the terms "EGU" and "power plant" interchangeably and do not use other terms unless it is necessary to explain a specific, relevant aspect of Texas or federal law. I also use the terms "natural gas-fired EGU" and "coal-fired EGU" when necessary to distinguish between generating units fueled by natural gas and coal, respectively.

6. For the reasons outlined below, it is my professional judgment based on my knowledge, experience, and expertise, that the "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" rule (the "Rule") signed by the EPA Administrator and published on the EPA website on August 3, 2015, will cause irreparable injuries to the PUCT and the State of Texas that can be redressed by this Court by staying the Rule during litigation. These irreparable injuries include:

- Expenditure of significant resources, beginning immediately, for unprecedented levels of coordination and planning between the PUCT, Texas Commission on Environmental Quality ("TCEQ"), other Texas state agencies, ERCOT, and other Independent System Operators ("ISOs"). These activities will also divert the resources of each of these entities from their respective core missions;

- Increased risk of electric reliability problems and necessitation of extensive work for the PUCT related to transmission planning and approval of generation plants, due to retirements of coal-fired EGUs that will likely occur well in advance of 2022;

- Seizure of control from state public utility commissions and state legislatures over planning, operations and resource decisions in electricity markets; and

- Insufficient time for the State of Texas to develop a State Plan, given that the Texas Legislature, the PUCT and ERCOT will be required to consider, design and implement extensive modifications to the existing market design for the ERCOT market and take other actions necessary to insure electric system reliability.

7. In the Rule, EPA is attempting to seize control from state public utility commissions and state legislatures regarding the planning, operation, and resource decisions made in electricity markets. It has long been the law of the land that authority over retail electricity markets nationwide (and wholesale markets within the ERCOT power region) are the sole province of state public utility commissions, except where the FPA[1] authorizes FERC regulation. Under the FPA, FERC has jurisdiction over "the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce . . . such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States."[2] Regulation of intrastate electricity markets is clearly the province of the States. As noted by the Supreme Court, "[w]ith the exception of the broad authority of the Federal Power Commission, now the Federal Energy Regulatory Commission, over the need for and

[1] 16 U.S.C. § 824 *et. seq*.

[2] 16 U.S.C. § 824(a).

pricing of electrical power transmitted in interstate commerce…these economic aspects of electrical generation have been regulated for many years and in great detail by the states."[3]

8. Environmental regulation has been limited to specific requirements on specific power plants, and has never been interpreted to grant EPA broad authority to dictate the operation of the entire electricity system in the United States including restrictions on the mix of power plants and other resources operated by utilities. The manner in which power markets are dispatched and directives concerning how much renewable energy should be integrated has never been under the purview of EPA. Rather, these decisions have been and are best left to states and the FERC as experts in these areas. The policies that EPA seeks to force through the Rule—namely renewable energy portfolio standards and cap-and-trade carbon emissions systems—have heretofore always and only been implemented through deliberation in state legislatures and state public utility commissions.

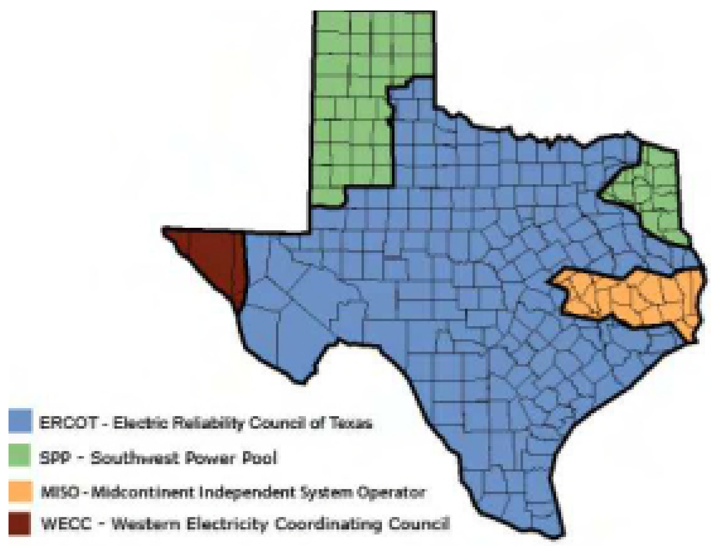
A. Overview of Texas's Unique Electricity Markets

9. Texas is unique among all states in that the majority of the state operates in a vibrant and extremely successful competitive wholesale and retail electricity market (the ERCOT power region), while other portions of the state operate within three distinct competitive wholesale markets that are overseen by the FERC. Texas utilities

[3] *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205 (1983) (citations omitted).

operating in these FERC-regulated markets remain subject to extensive PUCT jurisdiction regarding their retail utility service, as well as their power generation and transmission investments. Texas is also the only state that has utilities that operate in each of the three electrical interconnections in the United States. The map below illustrates the electric power regions in Texas.

Electric Power Regions in Texas



10. For the remainder of this declaration, I will use the term "ERCOT power region" or "ERCOT power grid" to describe the geographic area that exists solely within Texas for which the PUCT is solely responsible for overseeing the operation of wholesale and retail electricity markets. I will use the term "ERCOT, Inc." to describe the membership-based 501(c)(4) nonprofit corporation that has been designated by the PUCT as the ISO that administers the markets in this region.

11. Approximately 90% of Texas electricity consumption occurs within the ERCOT power region. ERCOT, Inc. is the only ISO in the continental United States that operates an electricity market that is wholly contained within one state and is not synchronously interconnected to the remainder of the country. The remaining 10% of electric consumption in Texas takes place in areas outside of the ERCOT power region.

12. ERCOT, Inc. is a membership-based 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the PUCT and the Texas Legislature. ERCOT, Inc.'s mission is to serve the public by ensuring a reliable grid, efficient electricity markets, open access, and retail choice. ERCOT, Inc. is responsible for overseeing the reliable operation of the electric grid for the ERCOT power region of Texas. ERCOT, Inc. manages the flow of electric power to approximately 24 million Texas customers—representing approximately 90 percent of Texas's electric load (i.e., demand for electricity) and approximately 75 percent of Texas's land area. As the ISO for the ERCOT power region, ERCOT, Inc. schedules and dispatches power on a grid that connects approximately 43,000 miles of transmission lines and more than 550 power generation units. ERCOT, Inc. also administers and maintains a forward-looking open market to provide affordable and reliable electricity to consumers in Texas. It manages financial settlement for the competitive wholesale bulk-power market and administers customer switching for seven million premises in competitive choice areas. Existing market policies and investments in transmission in the ERCOT power region have incentivized market participants to maximize the efficiency of the

generation fleet and develop new technologies including renewable generation. With recent investments in transmission, more than 14,000 megawatts of wind capacity have been integrated into the ERCOT power grid, and that number is projected to grow to at least 17,500 megawatts by 2016.[4] By way of comparison, ERCOT's most recent forecast of total capacity in ERCOT for 2016 is approximately 76,000 megawatts of non-wind generation capacity.[5] However, it is important to note that only a fraction of this installed wind capacity, because of its intermittent and seasonal characteristics, is assumed to be available to meet peak demand in the summer months. Specifically, ERCOT's forecast assumes that only 3,000 of the projected 17,500 megawatts of wind capacity—approximately 17%—will be generating energy at the time of peak demand. As will be discussed below, actual production of wind energy during peak demand periods can fall substantially below even this discounted number.

13. Ensuring reliable electrical power is critical to economic stability as well as human health and safety. The Federal Energy Policy Act of 2005 recognized the importance of ensuring reliability of electric grids by creating an Electric Reliability Organization ("ERO"). The ERO function for North America is performed by the North American Electric Reliability Corporation ("NERC"), which oversees a vast set

---

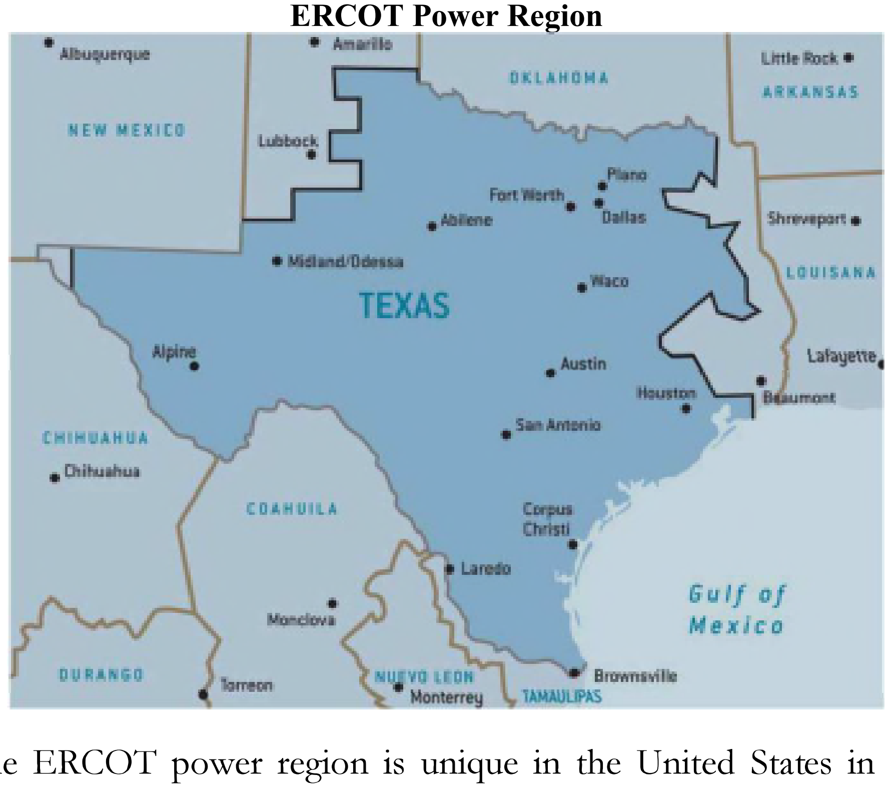
[4] *See* ERCOT, *GIS Report September 2015*, *available at* http://www.ercot.com/content/gridinfo/resource/2015/generation/GIS_REPORT__September_2015_FINAL.xls.

[5] *See* ERCOT, *Capacity, Demand & Reserves Report – May 2015*, *available at* http://www.ercot.com/content/gridinfo/resource/2015/adequacy/cdr/CapacityDemandandReserveReport-May2015.xls.

of reliability standards that are designed to ensure the reliability of the bulk power system. NERC has delegated portions of its oversight to regional reliability monitors; this delegation is approved by FERC. FERC has delegated this oversight to the Texas Reliability Entity ("TRE") as the reliability monitor for the ERCOT power region. ERCOT, Inc. is thus subject to TRE, NERC, and FERC for federal reliability standards. As explained in more detail below, ERCOT, Inc. is also accountable to the PUCT for state reliability standards.

14. The ERCOT power region, identified in the map below, covers most of Texas and includes the major load centers of Houston, Dallas, Fort Worth, San Antonio, Austin, Corpus Christi, and the Rio Grande Valley.

ERCOT Power Region



15. The ERCOT power region is unique in the United States in that it is wholly intra-state and is not directly (also referred to as synchronously) connected to

the two other U.S. grid interconnections (the Western and the Eastern Interconnections). Import and export of power from the ERCOT power region is limited to the capacity of five asynchronous ties linking ERCOT and other interconnections: two between the ERCOT power region and the Eastern Interconnection (with a combined capacity of 820 megawatts), and three between the ERCOT power region and the electrical grid in Mexico (with a combined capacity of 430 megawatts). Flows on these asynchronous ties are scheduled in advance of real-time operations by market participants; however, support from neighboring power regions can be received across these ties during grid emergency events. Aside from these limited asynchronous ties, from an electrical standpoint, the ERCOT power region is an island that must independently ensure its own electric reliability.

16. The power grids operating in Texas that exist outside of the ERCOT power region are located in far-west Texas (part of the Western Electricity Coordinating Council ("WECC")), North Texas and Northeast Texas (part of the Southwest Power Pool ("SPP")), and far-east Texas (part of the Midcontinent Independent System Operator ("MISO")). The non-ERCOT areas of Texas, other than far-west Texas which is in WECC, operate in multi-state competitive wholesale electricity markets that are overseen by FERC. MISO and SPP serve as Regional Transmission Organizations ("RTOs") in these areas and generally perform a role similar to that performed by ERCOT, Inc. within the ERCOT power region. The PUCT has been an active participant in MISO and SPP stakeholder processes encouraging the development of

advanced wholesale electricity market design features, such as ancillary services markets, development of real time and day ahead markets, and active transmission planning.

17. ERCOT, Inc. and the ERCOT power region are also unique among the nation's ISOs and RTOs and electricity markets in that they are subject to very limited and specific jurisdiction by FERC under the FPA. The transmission of electric energy occurring wholly within the ERCOT power region is not subject to FERC's rate setting authority under FPA Sections 205 or 206, nor is it subject to FERC's sale, transfer and merger authority under Section 203 of the FPA.[6] ERCOT, Inc.'s market rules and protocols are also not subject to FERC approval or oversight. Pursuant to Section 215 of the FPA, FERC does have jurisdiction to establish and enforce reliability standards for users of the bulk power system within the ERCOT power region. Finally, under FPA Sections 210, 211 and 212, FERC has limited jurisdiction to order certain entities within the ERCOT power region to interconnect and provide transmission service. Historically, FERC orders issued under FPA Section 212 that are applicable to entities operating in the ERCOT power region have expressly stated that the utilities in the ERCOT power region that are not currently considered public utilities under the FPA will not become public utilities and therefore subject to FERC jurisdiction for any purpose other than carrying out the provisions of FPA sections 210, 211 and 212. See e.g., Kiowa Power Partners, LLC, 99 FERC ¶ 61,251 (May 31, 2002).

[6] *See* FERC, *ERCOT*, http://www.ferc.gov/industries/electric/indus-act/rto/ercot.asp (last visited Oct. 12, 2015).

18. Under Tex. Util. Code Ann. § 39.001, as added in 1999, the Texas Legislature concluded "that the production and sale of electricity is not a monopoly warranting regulation of rates, operations, and services and that the public interest in competitive electric markets requires that, except for transmission and distribution services and for the recovery of stranded costs, electric services and their prices should be determined by customer choices and the normal forces of competition." Thus the Texas Legislature has declared that competitive wholesale and retail electricity markets are the preferred mode of operating electricity markets in the state, and state policy has conformed to this goal since 1999.

19. Under Tex. Util. Code Ann. § 39.151, the PUCT is required to certify an independent organization[7] to ensure the reliability and adequacy of the regional electrical network to ensure a reliable supply of electricity to Texas consumers. The PUCT certified ERCOT, Inc. as the independent organization responsible for overseeing the reliable operation of the electric grid for the ERCOT power region of Texas.

20. Under Tex. Util. Code Ann. §39.151(d), the PUCT is required to adopt and enforce rules relating to the reliability of the ERCOT power region. The PUCT may delegate to ERCOT, Inc. the responsibility for adopting and enforcing such rules, but any rules adopted by ERCOT, Inc. are subject to PUCT oversight and review.

[7] The terms "Independent Organization" and "ISO" are often used interchangeably within the Texas Utilities Code.

While power plants in Texas are also subject to reliability standards promulgated under § 215 of the FPA, the PUCT's authority to promulgate rules related to reliability within the ERCOT power region is independent of those authorities.

21. Under Tex. Util. Code Ann. § 39.151(d), the PUCT has complete authority to oversee and investigate ERCOT, Inc.'s organization to ensure that the organization adequately performs its functions and responsibilities.

22. The policy goals of the Texas Legislature outlined in Tex. Util. Code Ann. § 39.001 have been implemented through the development of a comprehensive framework for wholesale and retail competition for the ERCOT power region including the designation of ERCOT, Inc. as the independent organization responsible for the operation of the wholesale electricity market and as the entity responsible for ensuring the reliability and adequacy of the ERCOT power grid.

23. Inside the ERCOT power region, investor-owned electric utilities were required to separate into generation, transmission and distribution, and retail services companies as part of the transition to retail electric choice. The only service which is still subject to traditional regulation is the transmission and distribution function. The companies providing transmission and distribution service within the ERCOT power grid are known as transmission and distribution utilities ("TDUs"). Notably, as a result of this separation, EGUs within the ERCOT power region now bear the entirety of the risk of owning and operating their assets without guaranteed recovery of their costs or profit through regulated utility rates.

24. In areas of Texas outside the ERCOT power region, retail competition has been delayed indefinitely. In these areas of the state where competition has not begun, electric utilities are still vertically integrated, i.e., they have not separated into generation, transmission, and retail service companies, and are still subject to traditional cost-of-service regulation by the PUCT for their retail rates.

25. Neither an electric utility outside of the ERCOT power region nor a TDU operating inside the ERCOT power region may provide service to the public without a certificate of convenience and necessity ("CCN"). An electric utility or TDU that wishes to construct a transmission line must obtain a CCN from the PUCT before constructing the facility. The PUCT is also authorized to require utilities to construct new transmission facilities if needed to ensure safe and reliable service for the state's electric markets and consumers. Electric transmission CCN regulation by the PUCT is governed by Chapter 37 of the Texas Utilities Code.

26. Electric utilities and TDUs are also subject to cost of service rate regulation by the PUCT under Chapter 36 of the Texas Utilities Code and service quality regulation under Chapter 38 of the Texas Utilities Code.

27. Within the ERCOT power region, ERCOT, Inc. is responsible for ensuring open access to the transmission system, including managing the dispatch of power plants. ERCOT, Inc. largely performs this task through the operation of real-time and day-ahead markets that provide for security constrained economic dispatch.

28. Security constrained economic dispatch operates through ERCOT, Inc., dispatching power plants based upon their bids into ERCOT, Inc.'s administered markets, subject to transmission constraints. Thus, the inherent design of the markets motivates EGUs to bid at a level reflective of their short-run marginal costs, ensuring that in every interval that the power plant operates, its costs are at or below the market clearing price.

29. Tex. Util. Code Ann. § 39.001(c) provides:

> Regulatory authorities, excluding the governing body of a municipally owned electric utility that has not opted for customer choice or the body vested with the power to manage and operate a municipally owned electric utility that has not opted for customer choice, may not make rules or issue orders regulating competitive electric services, prices, or competitors or restricting or conditioning competition except as authorized in this title and may not discriminate against any participant or type of participant during the transition to a competitive market and in the competitive market.[8]

30. Under Tex. Util. Code Ann. § 11.003(18), "regulatory authorities" including the PUCT, may not make rules or issue orders regulating prices or competitors, or restricting or conditioning competition in the ERCOT power region's market except as authorized by Texas law.

B. Absent a Stay, the Rule Will Upend Texas's Competitive Electricity Markets

[8] TEX. UTIL. CODE ANN. § 39.001(c) (emphasis added).

31. The Rule represents a severe intrusion into the competitive wholesale and retail electricity markets that have operated in Texas since 2002 and is contrary to state policy requirements that, except in very limited instances dictated by the Texas Legislature, competitive forces, not governmental mandates, dictate the power generation mix within Texas. By seeking to mandate severe reductions in the output of EGUs fueled by coal and natural gas and force broader deployment of renewable energy at the expense of this fossil-fuel-based generation, the Rule upends Texas's carefully constructed competitive electricity markets and will prevent power plants that are otherwise economic and functional from generating electricity during many hours of the year. In some cases, the Rule will cause EGUs to completely shut down not because of market forces, but because of the regulatory fiat imposed by EPA that rations the amount of electricity the EGUs are permitted to produce. This lack of power generation will include periods when the operation of those plants is critical to maintaining the reliability of Texas's power grids, leading to a greater risk of blackouts. Absent a stay, the Rule will force EGUs to make irreversible decisions in the next one to three years that will have been unnecessary if the Rule is ultimately overturned on appeal. As discussed in more detail below, I believe the Rule will likely cause some EGUs to retire coal plants before 2022, which increases the risk of electric reliability problems for Texas before 2022 and beyond.

32. The Rule requires a substantial reduction in state-wide CO_2 emissions, and concordantly, generation from EGUs operating within Texas, and will have impacts

within each of the power regions within Texas. EPA's supporting documents indicate that Texas must reduce CO_2 emissions from a 2012 adjusted baseline of approximately 251 million tons to 221 million tons by the first interim period of 2022–2024, and, ultimately, to 189 million tons by 2030. Contrary to the purported "flexibility" that EPA claims exists in the Rule's compliance options, these emission limits absolutely necessitate a substantial reduction in electricity generation from fossil fueled power plants. Expressed as an emissions rate, EPA is requiring a one-third reduction in emissions, which implies substantially reduced output from coal and natural gas plants. EPA's baseline severely understates the reductions EPA is imposing on Texas because many coal plants in Texas had abnormally low output in 2012. Specifically, Energy Information Agency data shows that annual megawatt-hours produced from Texas coal EGUs in 2014 were approximately 10 million megawatt-hours higher than in 2012. The baseline also does not account for continued load growth in Texas that necessitates more electricity generation to meet consumer demand and preserve reliability.

33. The Rule calculates the emissions limitations and corresponding generation reductions through assumptions about heat rate improvements that can be made at existing coal plants, as well as assumptions about the ability of utilities operating in the three electrical interconnections across the country to collectively shift from coal generation to natural gas generation and install additional renewable energy. As discussed by the PUCT in its comments to the proposed version of the Rule, each of these assumptions is incongruent in relation to all three markets operating in Texas, but

especially in relation to the ERCOT power region. In particular, coal-fired EGUs in highly competitive electricity markets are well-motivated already to have made the efficiency improvements implied by the heat rate improvement building block. EPA's assumptions about the re-dispatch of power plants from coal-fired EGUs to natural gas-fired EGUs have been made arbitrarily and are not grounded in power system or pipeline network modeling or meaningful analyses regarding the reliability threats that would materialize from such a shift. The Rule also cavalierly assumes that the natural gas pipeline system has adequate capacity to reliably serve natural gas power plants operating at much higher rates and that such increases in natural gas combined cycle ("NGCC") operation can be authorized without excessive air-quality impacts. It also incorrectly presumes that the transmission grid can readily and quickly accommodate such a shift. Finally, assumptions about the ability of power markets to reliably incorporate large amounts of incremental renewable energy fail to recognize the operational modifications that must result in such markets and, within the ERCOT power market, the existing substantial penetration of these technologies and the unique reliability issues that already exist in the ERCOT power region at the current levels of renewable energy that are unprecedented elsewhere in the country. ERCOT, Inc. has already found a need to procure additional "ancillary services" or back-up fossil fueled capacity in order to reliably integrate the large amounts of wind generation that has connected to the ERCOT power grid.[9]

34. The Rule is fundamentally different from other environmental regulations affecting the electricity industry in that it goes far beyond requiring EGUs to make improvements at a particular plant to lower emissions, but instead mainly seeks to reduce output from fossil-fuel plants and replace it with other sources of electricity that exist elsewhere from the plant itself. Put another way, the primary "emissions control" contemplated by the rule is to not operate high CO_2-emitting power plants and to instead operate other sources of electricity more frequently.

35. Because the emissions performance rates are expressed as a lbs/MWh requirement, an EGU, if that rate were applied to the EGU, could not reach compliance by merely operating the plant less. As discussed by Mr. Richard Hyde in his declaration, these emissions standards are not achievable through traditional retrofit control technology. In fact, carbon-capture technology remains prohibitively expensive for either existing or new power plants to install. For example, in documents submitted to EPA in its permit application, FGE Energy estimated that the addition of carbon capture and sequestration technology would add $1.5 billion to the cost of a new 1,600-megawatt natural gas combined cycle power plant, and *would have been more expensive than*

---

[9] *See* ERCOT, *ERCOT Planning and System Costs Associated with Renewable Resources and New Large DC Ties, ERCOT's Response to the Request for Comments issued on August 13, 2014 (Sept. 12, 2014), available at* http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/42647_19_811674.pdf.

the power plant itself.[10] Notably, EPA is not requiring new combustion turbines to install carbon capture equipment.

36. Thus, for an EGU that operates, for example, a single natural gas fired power plant, if the performance rate of 771 lbs CO_2/MWh were applied to that EGU, the EGU would have no choice but to build—or pay others to build—non-emitting renewable generation to substitute for a portion of the output of the plant.[11]

37. For EGU owners that own a diverse mix of power plants, the Rule presumes that these owners will simply change the dispatch of the plants that they own. That assumption represents a fundamental misunderstanding of how organized electricity markets operate. Advanced wholesale electricity markets like the markets operating in Texas operate through unit-specific bidding and dispatch. Dispatch decisions on particular units are made by ISOs on the basis of bids made by the EGUs that, as discussed above, are generally made reflecting the short-run marginal cost of the units.

38. As discussed by Mr. Richard Hyde in his declaration, compliance with the Rule is likely not achievable without the implementation of an emissions or generation-

---

[10] *See* Letter from Emerson G. Farrell, CEO & President, FGE Power, to Aimee Wilson, Air Permits Section, EPA Region 6 (March 9, 2014), *available at* http://archive.epa.gov/region6/6pd/air/pd-r/ghg/web/pdf/fge-power-cost-estimates030914.pdf.

[11] For example, a 1,000-MW natural gas power plant that operates at a 50% annual capacity factor and has an emissions rate of 1,000 lbs. CO_2/ MWh, would need to build or pay others to build renewable energy capacity sufficient to generate 1.3 million megawatt hours per year to achieve the 771 lbsCO_2/MWh rate. This equates to 425 MW of wind generation operating at a 35% annual capacity factor or 675 MW of solar generation operating at a 22% annual capacity factor.

based trading system. In fact, the proposed Federal Plan would implement such a trading—or cap-and-trade—system. Such systems are intended to produce the same result as if the emissions performance rate is applied to each individual EGU—that is, high emitting EGUs will operate less (or completely shut down) and other sources of generation will operate more frequently. These systems require the purchases of economically valuable permits for emissions that raise the marginal cost of production of the plant and therefore make the power plant less economic compared to other sources. From the PUCT's perspective, either of these compliance options—application of the emissions performance rate to EGUs, or the imposition of a cap and trade system—create the same result: electric generation that would otherwise operate will be restricted from doing so, creating increased costs to consumers and an increased risk to system reliability.

39. The Rule's direction to EGUs not to operate assets that would otherwise be economic with all required environmental controls is in conflict with Texas laws and regulations that prohibit market power abuses, including the withholding of power.[12] As a result, absent a stay, the Texas Legislature, PUCT, and market operators such as ERCOT, Inc., will be required to expend significant resources revising Texas laws and regulations, as well as market rules and procedures.

[12] The PUCT's market power abuse regulations are primarily outlined in PUCT Rule § 25.504.

40. The ERCOT power region also has robust growth in consumer demand compared to other parts of the country, with an expectation of an average of 1.4% annual demand growth between now and 2022. Peak demand growth forecasts suggest a need for a minimum of an additional 850 MW of new power plant capacity each year simply to maintain existing reserve margins.

41. Even though the ERCOT power region is summer-peaking, there are also occasionally winter-weather related reliability strains given the prevalence of electric heating systems in portions of the state. Because of constraints on the natural gas pipeline system that limit the ability of natural gas-fired power plants to maximize output, the operation of Texas's coal-fired power plants are vital during these periods to ensure reliability.

C. Absent a Stay, the Rule Will Likely Cause Degraded Reliability

42. While the Rule does not require actual emissions reductions until 2022, the implied reductions that coal-fired power plants will be expected to make will drastically impact the expected economics of these power plants over their remaining life. As the owners of these power plants are required to make decisions about capital expenditures and the ongoing operation of these plants in planning horizons measured in decades, they likely will now be required to severely discount future cash flows due to this required reduction in operation. It is also important to note that other rules already promulgated (Mercury and Air Toxics Rule) or proposed by EPA (Regional Haze Rule), if they are ultimately upheld by the courts are a significant driver of these

capital expenditure needs. As such, absent a stay of the Rule, owners of these power plants will be more likely to decide to retire power plants rather than make additional capital expenditures that they would not be able to recoup under the restricted operation required by the Rule. These decisions are likely to occur far in advance of 2022, in some cases may occur imminently, and may threaten reliability of the Texas power grid if large retirements are announced in a time period that would not allow adequate time for the construction of replacement power plants or the transmission infrastructure to facilitate power transfers from new sources.

43. For example, the CO_2 reduction required by the Rule, when expressed as a mass reduction requirement, would be greater than the 2012 CO_2 emissions of the six largest coal-fired EGUs in the ERCOT power region, representing nearly 5,000 megawatts of summer capacity. This calculation of the amount of capacity at risk for early retirement is consistent with a study released by ERCOT, Inc. on October 16, 2015 (referred to hereafter as "the ERCOT Study") that analyzed the potential impacts of the Rule on the ERCOT power market. Specifically, the ERCOT study found that the Rule is likely to result in the retirement of at least 4,000-4,700 MW of coal-fired EGUs within the ERCOT region. Importantly, ERCOT, Inc. notes that this result likely represents "a lower bound on the number of potential coal unit retirements" because their model does not require a market rate of return for upgrades that investors

in EGUs operating in a competitive market require.[13] The ERCOT study also notes that model results indicate that in addition to these retirements, several additional coal EGUs operate at extremely low capacity factors (less than 20%) during off-peak months and would likely suspend their operations during these months, increasing the reliability risks during cold weather events that I discussed above. The ERCOT study also found that, consistent with the above discussion regarding investment decisions by power plant owners, many of the units would be retired before 2022 due to the timing of the requirements of other environmental regulations.[14] In some cases, these retirements will occur as early as 2016.[15]

44. The ERCOT power region is a summer-peaking region, with peak demands that have reached a record of 69,783 megawatts in August 2015. During peak periods of the summer of 2015, the ERCOT power region had less than 5,000 MW of excess capacity available to serve customers without resorting to emergency actions on numerous occasions, including periods on seven days during July and August 2015. During portions of those days, the emergency actions would have included implementing emergency demand response programs, and, if those actions were not sufficient to preserve reliability, ERCOT, Inc. would have been required to order the

[13] ERCOT, *ERCOT Analysis of the Impacts of the Clean Power Plan: Final Rule Update* at 11 (October 16, 2015).

[14] *Id* at 7.

[15] *Id*. at 3.

rotating outages of customers. This illustrates the real potential for degraded reliability that will occur in the ERCOT power region if the Rule results in substantial early retirements of power plants. Plant retirements of this magnitude would have caused a need for emergency actions to maintain reliability in 2015, and in upcoming years would be likely to result in even more severe impacts given the electricity demand growth that Texas is experiencing.

45. While EPA claims that there are numerous "reliability safety valves" in the Rule, these mechanisms do not ameliorate the impacts of the near-term plant retirements that are likely to occur prior to the compliance period in 2022. Additionally, once the compliance period begins in 2022, the reliability safety valve mechanism in the Rule will be of little value because power plants will, at that point, have been closed for a significant duration of time.

46. Decisions to retire coal-fired power plants and associated mining activities are irreversible due to the labor and other resource needs associated with those plants. Power plant and mine operations rely on a labor force with specialized skill sets and expertise and often require site-specific, on-the-job training. Once power plant and mine operations are ceased and workers are laid off, experienced personnel cannot be readily rehired or new personnel quickly trained. Thus, Texas and its power markets will be irreversibly harmed through higher prices and degraded reliability when EGUs are forced to make premature retirement decisions due to the Rule. Decisions by power plant owners to retire these plants early in light of the Rule will require the PUCT,

market operators such as ERCOT, Inc., and transmission owners to immediately start planning and constructing additional transmission in these areas, and/or execute Reliability Must-Run ("RMR")[16] agreements with these power plants to keep them online. The RMR arrangement provides compensation schemes that will impose costs upon consumers. Thus, even if a power plant could reopen following the overturning of the Rule, there will still be costs and infrastructure investment that cannot be recouped. Therefore, these harms will be irreparable.

D. Absent a Stay, the Rule Will Impose Substantial Cost, Time, and Labor Burdens on the PUCT.

47. The threat to reliability resulting from the Rule will impose tremendous burdens on the PUCT and ordinary Texans. Absent a stay of the Rule, the Texas Legislature, the PUCT, and ERCOT, Inc. will be required to consider, design and implement extensive modifications to the existing market design for the ERCOT power region and engage in other activities to ensure that reliability within ERCOT is maintained. These efforts will be extremely costly in time, money, and labor, and but for the Rule, these efforts would not be necessary. If the Rule is not stayed it will be impossible for Texas to undo the changes to its electricity markets that are mandated

[16] RMR agreements are rare, temporary arrangements used by ERCOT, Inc. to provide out-of-market compensation to an EGU that would otherwise exit the market if ERCOT, Inc. determines that the continued operation of the EGU is necessary for voltage support, stability, or management of transmission constraints. RMR agreements are generally short term arrangements to provide time for ERCOT, Inc. and market participants to find alternatives to solve the reliability issues caused by the EGU's closure. Notably, under current regulations, EGUs cannot be compelled to enter into RMR arrangements.

by the Rule, which will result in irreparable harm to the PUCT, ERCOT, Inc., Texas's electric markets and Texas electric customers.

48. EPA has argued in court pleadings that states retain the option to do nothing and await whatever Federal Plan is imposed on a state by EPA. While that may be true for environmental regulators, it is not an option for the PUCT to simply sit by and hope the lights stay on while the validity of the Rule is being litigated. Whether Texas develops a State Plan, or EPA issues a Federal Plan, the impacts and irreparable harm to the PUCT are the same. The PUCT's responsibility to ensure reliable electric service dictates that the PUCT will be forced to address and mitigate the impacts of power plant closures caused by the Rule independent of Texas' decision regarding the filing of a State Plan. The PUCT will be forced to act precisely because EPA does not have jurisdiction to address electricity market design, ensure reliability or engage in transmission planning. The Rule therefore presents two equally untenable options for the PUCT. The PUCT is required to either engage in substantial work that conflicts with Texas law and policy decisions of the Texas Legislature in order to mitigate the impacts of the Federal Plan to protect reliability, or expend substantial resources to assist in the crafting of a State Plan that attempts to mitigate the destructive impacts of the Rule. In either event, only a stay of the Rule can prevent irreparable harm to the PUCT.

49. EPA's attempt to force reductions in the output of coal and natural gas-fired EGUs is inconsistent with Texas's approach to electricity regulation which relies

on the forces of competition to incentivize market efficient development and operation of power plants. In doing so, the Rule effectively requires Texas to fundamentally reorganize its electric grid in the way it generates, transmits, and consumes power. By rationing the amount of electricity that can be produced by fossil-fueled generation assets and forcing expenditures on transmission infrastructure that would otherwise not be necessary, the Rule will result in increased prices and reduced reliability. The ERCOT Study finds that, by 2030, wholesale market prices in the ERCOT power region will rise by up to 44% due to the loss of EGUs that would otherwise continue to operate, and that estimate does not include the costs of adding transmission infrastructure, additional ancillary services, or potential reliability must-run contracts. I discuss why each of these additional costs are likely below.

50. These dynamics exist even in the areas of Texas that are not within the ERCOT power region. The majority of Texas's electricity customers outside of the ERCOT power region are served by investor-owned utilities ("IOUs") subject to the oversight of the PUCT for their retail rates, service quality, and operations. The non-ERCOT IOUs operating in Texas are each part of multi-state utility systems. The non-ERCOT areas of Texas are located in far-west Texas, North Texas, and far-east Texas.

51. El Paso Electric Company ("El Paso"), which is part of WECC, serves far-west Texas. WECC is a non-profit corporation whose primary function, as a Regional Entity through delegated authority by NERC, is to assure bulk electric system reliability in the geographic area known as the Western Interconnection, which is

comprised of fourteen states in the western U.S. as well as two Canadian provinces and Northern Baja Mexico. Peak Reliability is a 501(c)(4) entity that retains registration for, and fulfills the duties of, the Reliability Coordinator, as defined by NERC, and as delegated by the WECC, for its Reliability Coordinator Area in the Western Interconnection. Peak Reliability's Reliability Coordinator Area includes all or parts of fourteen western states including Texas, British Columbia, and the northern portion of Baja California, Mexico.

52. The Panhandle portion of Texas, including the city of Amarillo and areas around Lubbock, is served primarily by Southwestern Public Service Company ("SPS"), which operates within the SPP. SPP is a not-for-profit organization that operates as an RTO with members in nine states that is subject to oversight by FERC and a Regional Entity through delegated authority from NERC. Far-northeast Texas is served by Southwestern Electric Power Company ("SWEPCO"), which also operates within SPP.

53. Finally, in far-east Texas, Entergy Texas, Inc. ("ETI"), operates in MISO, which is a not-for-profit organization that operates as an RTO with members in fifteen states and the Canadian province of Manitoba and is also subject to oversight by FERC.

54. Both MISO and SPP are required by FERC to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity.

55. SPP operates regional security-constrained, economically dispatched markets. This model considers both reliability and economics. Reliability actions and

generation dispatch provide regional solutions to needs over a multi-state area. These solutions are not limited to state boundaries. SPP performs regional transmission planning and directs transmission construction for its member companies. All generator interconnection requests and transmission service requests are directed to and processed by SPP. Transmission planning is a significant function of SPP and the other RTOs. Transmission planning, design, permitting and construction are very time-intensive. In SPP, planning, designing and construction of transmission lines can take up to eight and a half years.

56. Notably, Texas utilities operating in WECC, MISO, and SPP are all on the end of their respective interconnections. Thus, each of the utilities tend to be transmission-constrained, meaning that the existing transmission grid has limitations on how much power can be imported into Texas from other states.

57. Each of the utilities operating in the non-ERCOT power regions of Texas operates fossil-fueled electricity generation units that will be impacted by the Rule. These utilities are required to request and obtain approval from the PUCT to construct new generation plants or transmission facilities.

58. Two of these utilities—namely SPS and SWEPCO—each have large amounts of coal-fired generation. The Rule will require these utilities to develop plans to reduce or replace the output of these plants with new power plants and develop other infrastructure in order to ameliorate the reliability impacts of the Rule. Due to the time

it takes to plan, permit, and construct new transmission and generation resources, these efforts will have to begin well in advance of 2022.

59. However, these efforts are unlikely to be concluded even by 2022. For example, if SWEPCO does not have sufficient capacity in Texas to make up for the forced retirement of some of its coal units, SWEPCO would likely be forced to purchase capacity (assuming such capacity were even available) from outside Texas to serve its customers. Because SWEPCO is located on the western seam between SPP and the ERCOT power region, there is currently insufficient transmission from which to import the capacity that would be needed to replace its retired coal units. As noted above, transmission planning in SPP is a multi-state effort and can take as long as eight and a half years and require approvals from both the SPP and a number of states. EPA has failed to recognize the significant investment in new capacity and new transmission that SWEPCO would likely be required to make under the Rule. This problem would be exacerbated in the winter months when natural gas curtailment issues due to weather are most likely to arise.

60. Additionally, because the SWEPCO system spans multiple states, it is probable that any additional transmission improvements will require approvals from states other than Texas. Should any of the impacted states deny applications to build new transmission lines into Texas, SWEPCO, and ultimately the PUCT, will be unable to ensure reliability to its Texas customers.

61. Because the PUCT will be required to process requests for new power plants and transmission lines even if they are ultimately deemed unnecessary because the Rule is overturned, the PUCT will be irrevocably harmed by having to dedicate and divert resources to these efforts to the detriment of other regulatory work and state policy goals. As discussed below, planning, permitting and construction of transmission in the non-ERCOT areas of Texas will be especially difficult for Texas and will require an unprecedented level of coordination among multiple states within the SPP and MISO markets.

62. While the PUCT generally does not have regulatory jurisdiction over the operations of electric cooperatives and municipally owned utilities, I am aware that a number of cooperatives within Texas receive power from predominately coal EGUs, and thus have similar concerns to those I have discussed with respect to SWEPCO's generation planning. Because the PUCT is required to approve new transmission lines constructed by electric cooperatives and municipally owned utilities, the PUCT will be impacted by the need to dedicate resources to processing these requests in a manner similar to that discussed for other Texas utilities.

E. Absent a Stay, the Rule will have Substantial Impacts on the PUCT's Activities Related to Transmission Planning and Reliability

63. The Rule further contemplates that electric generation unit owners or states will take steps to incentivize or otherwise install large additional amounts of

renewable energy to replace the production from coal and natural gas-fired power plants that will be unable to operate under the emissions limits established in the rule.

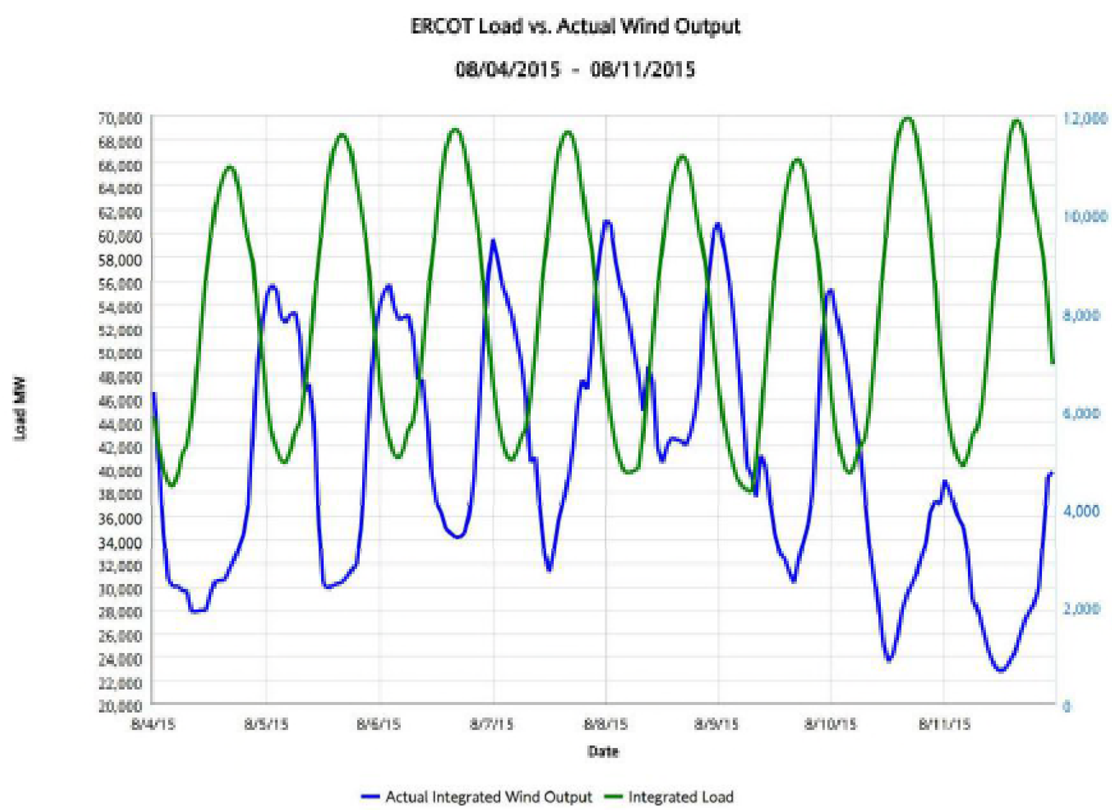
64. The Rule is fundamentally flawed in its assumption that all sources of electricity production are always substitutable. In many cases they are not. Fossil-fueled generation plants often provide services to power grids that intermittent renewable energy sources cannot. The location of power plants also has dramatic impacts on the ability to reliably meet power demand. Thus, it is simply not the case that megawatt hours produced in East Texas at a coal plant can always be replaced one-for-one with renewable energy from a wind farm in West Texas. As ERCOT, Inc. puts it, "[c]oal resources provide essential reliability services necessary to maintain the reliability of the grid. The retirement of coal resources will require studies to determine if there are resulting reliability issues, including whether there are localized voltage/reactive power control issues and the necessity of potential transmission upgrades . . . ."[17]

65. Wind generation in Texas also tends to produce only a fraction of its output during the times of peak demand. For purposes of planning, ERCOT, Inc. presumes that only 12% of wind capacity in West Texas and only 56% of wind capacity along the Texas coast will generate electricity during the summer peak. However, on many peak summer days, actual wind production can be substantially below these

[17] ERCOT, *ERCOT Analysis of the Impacts of the Clean Power Plan: Final Rule Update* at 11 (October 16, 2015).

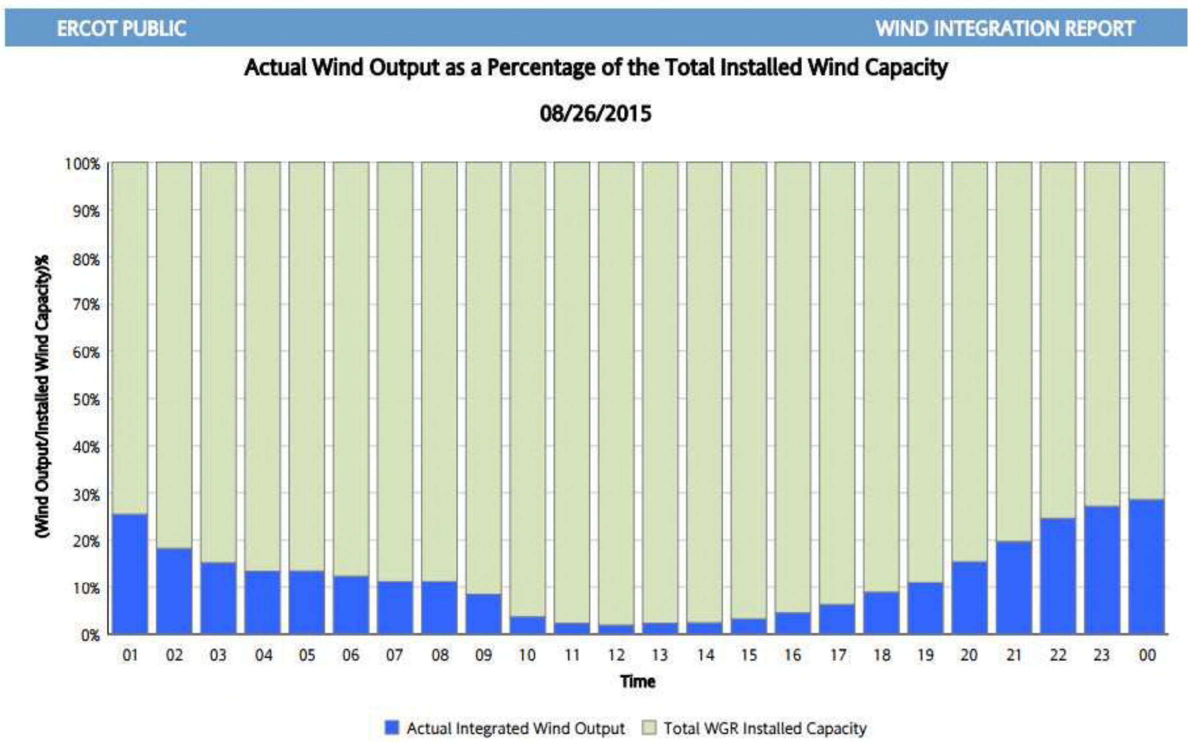
planning estimates. On such days, the availability of fossil generation is critical to maintaining reliability.

66. The following chart[18] illustrates the pattern of wind energy production together with electricity demand in the ERCOT power region on typical summer weeks. Wind energy production (the green line) is generally at its maximum (though still less than 100% of capacity) around midnight, and is generally at its minimum during afternoon hours when demand (the blue line) is at its highest.



[18] *See* ERCOT, *Wind Integration Report: 08/11/2015, available at* http://www.ercot.com/content/gridinfo/generation/windintegration/2015/08/Wind%20Integration%20Report%2008-11-2015.pdf.

67. Illustrated a different way, the following chart[19] shows actual wind production as a percentage of overall wind capacity during a day in August 2015. As can be seen, actual wind production varies throughout the day, never exceeds 30% of installed capacity, and approaches zero percent during the early afternoon hours when demand is rising the fastest.

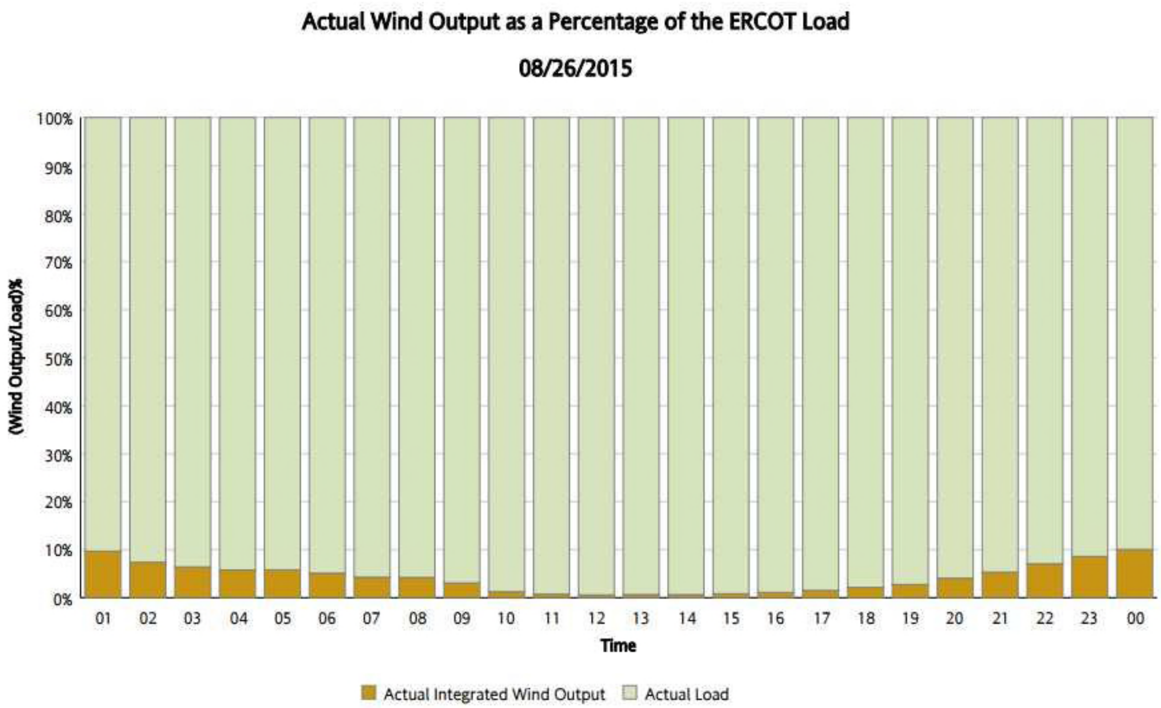


68. Finally, to demonstrate the reliability aspects of this variability, the following chart[20] illustrates actual wind generation as a percentage of total customer

[19] *See* ERCOT, *Wind Integration Report: 08/26/2015, available at* http://www.ercot.com/content/gridinfo/generation/windintegration/2015/08/ERCOT%20Wind%20Integration%20Report%2008-26-15.pdf.

[20] *Id.*

demand on the same day. As can be seen, even though installed wind capacity was approximately 12,000 MW, actual wind production never served more than 10% of total customer demand, and provided virtually none of the energy consumed by customers in the afternoon hours. As discussed earlier, if the Rule forces early retirements of fossil-fueled generation, Texas will experience adverse reliability impacts and challenges on days like this when the intermittent wind generation is unavailable.[21]



69. In Texas, renewable energy sources have generally been developed in remote areas in West Texas due to higher wind speeds. This has required substantial

[21] While solar energy generation has the potential to produce electricity more in line with consumer demand at peak periods, there is currently less than 200 MW of large scale solar energy installed on the ERCOT power grid. Additionally, I have reviewed studies that suggest that maximum solar energy production in Texas is likely to occur around the noon hours, with declines in production occurring in late afternoon, which is the time electricity production peaks.

new transmission investment in order to move electric energy generated by these sources to the major demand centers in the eastern and central parts of the state. This area of the state is also characterized by low customer demand and little dispatchable fossil fuel generation. As such, Texas is currently expending significant effort to address unique reliability needs related to voltage support, system inertia, and stability issues that can arise in such circumstances. It is simply not the case that additional intermittent renewable generation can in all cases interchangeably replace the fossil generation that the Rule will prevent from operating.

70. Tex. Util. Code Ann. § 39.155(b) requires ERCOT, Inc. to submit an annual report to the PUCT identifying existing and potential transmission system constraints and system needs within the ERCOT power region. In support of this and other requirements, ERCOT, Inc. conducts a comprehensive, ongoing transmission planning process to identify the need for additional transmission in the ERCOT power region. In the most recent ERCOT, Inc. report to the PUCT, ERCOT, Inc. identified substantial transmission system improvements needed to accommodate demand growth in the Houston, Dallas Fort-Worth, San Antonio and Rio Grande Valley regions, including needs related to large new industrial projects.

71. Beginning in 2005, Texas embarked on a multi-year plan to dramatically expand transmission infrastructure to support renewable energy known as the Competitive Renewable Energy Zone ("CREZ") transmission project. The CREZ project adopted by the PUCT provided for a total of approximately 18,500 MW of

transfer capacity from West Texas to the rest of the state. This was the maximum amount that the PUCT was willing to approve given concerns about the reliability impacts of renewable energy capacity beyond that amount.

72. From the time the Texas Legislature enacted legislation in 2005 directing the PUCT to designate areas of the state as CREZ's until the final CREZ transmission lines were completed in 2014 was approximately nine years. From May 2005 to December 2013, the PUCT designated CREZ zones, selected transmission providers to build the transmission, and decided 37 contested transmission CCN applications which authorized the construction of 3,589 miles of transmission lines at a cost of approximately $6.9 billion.

73. Thus, even with the advantages described above, the final CREZ transmission line project took nine years from the enactment of Legislative authority, comprehensive planning efforts at ERCOT, PUCT consideration and approval of the lines, to final construction.

74. For generation interconnection requests, ERCOT, Inc. conducts a screening study to determine the proposed generator's impacts on the system. Once the full interconnection studies are performed by the transmission service provider and accepted by all parties, the market participant and transmission service provider may enter into a Standard Generation Interconnection Agreement ("SGIA"). The duration of the interconnection process can vary greatly, generally ranging from one to four years from the start of the process to commercial operations.

75. Again, it is important to note that the PUCT will be forced to expend resources related to this transmission planning unless the Rule is stayed. Even if Texas declines to file a State Plan, the PUCT remains charged with ensuring reliable electric service across the state. Given that the Rule will likely result in potential early retirements of power plants or the early deployment of additional renewable energy, the PUCT will have no choice but to expend resources as EGUs, electric utilities, and ERCOT, Inc. are forced to begin planning for compliance with the Rule. The ERCOT Study highlights that the coal EGU retirements forced by the Rule will result in the overloading of 10 circuits and 143 miles of 345 kilovolt (kV) transmission lines; 31 circuits and 147 miles of 138 kV transmission lines; 6 circuits and 39 miles of 69 kV transmission lines; and almost a dozen transformers. The addition of a similar amount of transmission to relieve these overloads is likely to cost in excess of $600 million (financed by Texas ratepayers) and take at least five years to plan, route, approve, and construct. The ERCOT Study also finds a likely growth in renewable generation comparable to that facilitated by the CREZ project, creating the specter of a need for billions of dollars of additional transmission to fully integrate these resources. The dedication of resources to ameliorate this impact of the Rule will mean the PUCT will be irrevocably harmed by having fewer resources to appropriately deal with other priorities of the state, such as planning for demand growth and conducting our normal regulatory activities.

76. Texas is generally regarded as a jurisdiction where transmission is built relatively expeditiously. This is due to the centralized transmission planning function at ERCOT, Inc. and the PUCT as the sole regulator needed to approve new transmission lines. Even with these advantages, the final CREZ transmission line project took nine years from the enactment of Legislative authority, comprehensive planning efforts at ERCOT, Inc., PUCT consideration and approval of the lines, to final construction. Because the Rule requires the initial reductions in carbon dioxide output in 2022, EPA has not provided sufficient time for Texas to perform a similar analysis and transmission planning related to the reliability impacts of the Rule.

77. Additionally, while the CREZ transmission upgrades provided substantial new transmission capacity to accommodate renewable energy, these new circuits will not provide sufficient capacity to reliably integrate the large additional amount of renewables necessary to meet the requirements of the Rule. EPA's assumed incremental renewable energy generation levels by 2030 for the ERCOT power region is three times the level estimated for 2012 and none of the renewable energy installed prior to 2012 can be used by EGUs or the state to demonstrate compliance. Also, if the locations of new renewable generation do not coincide with CREZ infrastructure, significant further transmission improvements will be required. Given the need to increase the amount of renewable resources in order to achieve compliance with the requirements of the Rule, it is likely that significant new transmission infrastructure would be required to connect new renewable resources.

F. Absent a Stay, the Rule will Usurp Texas's Authority Over Renewable Energy Policy

78. The Texas Legislature adopted a renewable energy portfolio standard ("RPS") in 1999, and increased it in 2005. Under the RPS adopted by the Texas Legislature, all entities in ERCOT that sell electricity are required to either directly own or purchase renewable energy capacity. Entities that do not own or purchase renewable energy capacity are required to purchase renewable energy credits ("RECs") to satisfy the RPS. The PUCT has adopted a rule establishing a REC trading program. Under the REC trading program, RECs may be generated, transferred, and retired by renewable energy power generators certified under the rule, as well as retail entities and certain other market participants. Through the RPS, the Texas Legislature mandated a minimum amount of electric generation capacity from renewable energy sources be installed in the state. Texas has met its existing mandates. In light of this, the Texas Legislature has not indicated a preference to increase these mandates, and considered legislation to repeal Texas's RPS law in the last legislative session.

79. The Rule seeks to usurp the roles of the Texas Legislature and PUCT in determining renewable energy policy in Texas. As discussed in paragraph 36, if the emissions performance rate is applied to EGUs, many EGUs will have no choice but to build new renewable energy capacity, or pay for others to build it on their behalf. The end result is identical to state RPS regulations, except the requirements are dictated

by EPA and not the Texas Legislature and also do not consider other important factors, including cost and reliability, that have been considered by the Legislature.

80. Should Texas elect to file a State Plan, neither the PUCT nor Texas can guarantee that renewable energy resources will grow at a rate sufficient to meet the requirements of the rule without amendments to Texas' RPS, particularly in light of the fact that the Rule only permits states to count new renewable energy resources installed after 2012 for compliance purposes. In fact, EPA makes it clear that voluntary or market driven renewable energy goals will not be considered "state enforceable measures."[22] Thus, in order to provide guarantees that the renewable energy required by the rule will be installed, the Texas Legislature must first decide whether to amend Texas law to impose a new RPS requirement in Texas. The Texas Legislature is next scheduled to meet beginning in January 2017, and I agree with the logistical, financial, and practical challenges that this presents the State of Texas as explained in Mr. Hyde's declaration.

81. The ERCOT Study also highlights a critical factor that EPA has failed to consider. Regardless of whether Texas files a State Plan or has a Federal Plan imposed upon it, there is a limit to the amount of intermittent renewable energy that the ERCOT grid can accommodate. In 2014, 10.6% of the ERCOT power region's annual

[22] EPA, *"Incorporating RE and Demand-Side EE Impacts Into State Plan Demonstrations"*, Technical Support Document, Docket ID No. EPA-HQ-OAR-2013-0601 (July 31, 2015) at p. 16 n. 17.

generation came from wind, and at its highest level of penetration, wind energy served approximately 41% of all customer demand. The ERCOT Study forecasts that the Rule will force significant growth in additional wind and solar resources, which together may comprise 27% of total generation by 2030. "Significant ramping capability and operational reserves" from fossil EGUs is required to maintain grid reliability during these periods of high renewable energy production, but at a high enough level of production, ERCOT, Inc. will likely be forced to curtail renewable energy output to keep the grid stable.[23] As renewable resources are curtailed, production is reduced, and it is more likely that compliance with the Rule cannot be achieved—a scenario that the Rule does not contemplate. These issues are among the factors that the Texas Legislature has been deliberating as it has discusses Texas's existing RPS law and precisely why these issues are properly left to state legislatures and electricity regulators to decide.

G. Absent a Stay, the Rule will Require Unprecedented Coordination Between the PUCT, other Texas State Agencies, ERCOT, Inc., and other ISOs

82. The additional state laws required to implement the Rule in Texas would in turn almost certainly require the adoption of new or amended rules by each affected state agency, including the TCEQ, PUCT, and possibly the Railroad Commission of Texas ("RRC") and would also require interagency contracts or agreements between

[23] ERCOT, *ERCOT Analysis of the Impacts of the Clean Power Plan: Final Rule Update* at 13 (October 16, 2015).

these agencies. The Rule would also likely require changes in operating procedures for all markets operating in Texas and the establishment of carbon dioxide emissions trading regimes—both of which would also be costly and time-consuming processes. If the Rule is not stayed, its will require the expenditure of significant time and resources by Texas state agencies and market operators in Texas.

83. The Rule will require unprecedented coordination among multiple Texas state agencies, including the PUCT, TCEQ, and the RRC. The TCEQ is the Administrator of Texas's air quality program under the Clean Air Act. The RRC is a Texas state agency that serves as the primary regulator of the oil and gas industry in Texas. The RRC: 1) oversees all aspects of oil and natural gas production, including permitting, monitoring, and inspecting oil and natural gas operations; 2) permits, monitors, and inspects surface coal and uranium exploration, mining, and reclamation; 3) inspects intrastate pipelines to ensure the safety of the public and the environment; 4) oversees gas utility rates and ensures compliance with rates and tax regulations; and 5) promotes the use of propane and licenses all propane distributors.

84. The Rule clearly intermingles matters within the jurisdiction and expertise of the TCEQ, PUCT, and the RRC. While TCEQ would likely be the agency delegated authority to submit and monitor compliance with a State Plan, it will need myriad assistance from the PUCT, RRC, and other State agencies in formulating the State Plan. Further, it will be necessary for these agencies to coordinate with the ISOs and RTOs operating in Texas (ERCOT, SPP, and MISO), the WECC and Peak Reliability

regarding the reliability impacts of the Rule. The level of coordination among Texas state agencies and the ISOs and RTOs required under the Rule is significant and will involve the immediate expenditure of considerable time, effort and money in order to meet either the September 2016 or September 2018 deadline for submission of a State Plan. The cost and expense of this coordination effort will cause Texas irreparable harm if the Rule is not stayed.

85. Texas's unique composition of fully-competitive service territories adds an additional layer of complexity and potential for irreparable harm if the Rule is not stayed. Particularly with respect to Texas utilities operating outside of the ERCOT power region, consideration of any State Plan will necessarily involve the PUCT consulting with states in the MISO, SPP, and WECC regions, along with the respective grid operators, to assure that actions taken regarding the State Plan respect reliability concerns and other applicable regulatory requirements and authorities in each of those jurisdictions.

86. Such consultation will need to occur even if Texas ultimately decides to file a Texas-only State Plan because Texas, as well as all of the other states and applicable regulatory authorities such as FERC and NERC, will need to understand the other states' plans in order to properly assess the reliability impacts of those plans. The Rule requires a staggeringly complex level of interaction that involves several state agencies including the PUCT and TCEQ, three distinct RTOs, and all the states within the footprints of those RTOs, the end result of which is that Texas has to accomplish not

only significant intrastate agency coordination but also significant coordination with almost half of the states in the country. In order to meet the deadline for filing a State Plan (September 2016 or September 2018 if an extension is granted) this extremely complex and resource intensive coordination process would have to begin immediately. Obviously, Texas would be irreparably harmed by the expenditure of considerable time and resources needed for this coordinated effort if the Rule is ultimately overturned on appeal.

87. EPA has put Texas in a no-win situation. Texas must either submit a State Plan—and thereby cede its authority over the state policy regarding electricity markets in the state—or risk imposition of a Federal Plan by EPA, which would at a minimum introduce severe distortions into the State's electricity markets, and further, could effectively usurp Texas's authority over its electricity markets with respect to the State's preference for competitive market outcomes. Both are untenable outcomes for Texans.

H. Absent a Stay, Texas will not have Sufficient Time to Develop a State Plan

88. In order to implement the Rule, the PUCT also would be required to amend a significant number of its rules. Some of the rule changes would also require changes in Texas law before they could be adopted by the PUCT. Possible PUCT rule changes resulting from the Rule that have been identified to date include:

- 16 Tex. Admin. Code § 25.51 (Power Quality);
- 16 Tex. Admin. Code § 25.53 (Electric Service Emergency Operations Plans);

- 16 Tex. Admin. Code § 25.54 (Cease and Desist Orders to PGCs);
- 16 Tex. Admin. Code § 25.93 (Wholesale Electricity Transaction Information);
- 16 Tex. Admin. Code § 25.91 (Generating Capacity Reports);
- 16 Tex. Admin. Code § 25.109 (Registration of Power Generation Companies and Self Generators);
- 16 Tex. Admin. Code § 25.172 (Goal for Natural Gas);
- 16 Tex. Admin. Code § 25.173 (Goal for Renewables);
- 16 Tex. Admin. Code § 25.174 (Competitive Renewable Energy Zones);
- 16 Tex. Admin. Code § 25.181 (Energy Efficiency Goal);
- 16 Tex. Admin. Code § 25.183 (Reporting and Evaluation of Energy Efficiency Programs);
- 16 Tex. Admin. Code § 25.200 (Load shedding, Curtailments and Redispatch);
- 16 Tex. Admin. Code § 25.211-213 (Rules related to Distributed Generation);
- 16 Tex. Admin. Code § 25.217 (Distributed Renewable Generation);
- 16 Tex. Admin. Code § 25.235 (Fuel Costs);
- 16 Tex. Admin. Code § 25.236 (Recovery of Fuel Costs);
- 16 Tex. Admin. Code § 25.237 (Fuel Factors);
- 16 Tex. Admin. Code § 25.238 (Purchased Power Capacity Cost Recovery Factor);

- 16 Tex. Admin. Code § 25.251 (Renewable Energy Tariff);
- 16 Tex. Admin. Code § 25.261 (Stranded Cost Recovery of Environmental Cleanup Costs);
- 16 Tex. Admin. Code § 25.361 (ERCOT);
- 16 Tex. Admin. Code § 25.365 (Independent Market Monitor);
- 16 Tex. Admin. Code § 25.421 (Transition to Competition for a Certain Area Outside the ERCOT power region);
- 16 Tex. Admin. Code § 25.422 (Transition to Competition for Certain Areas in the Southwest Power Pool); and
- 16 Tex. Admin. Code §§ 25.501-508 (ERCOT wholesale market design rules).

89. Even if the Texas Legislature passed laws giving the PUCT the authority to adopt or amend existing rules necessary to carry out the mandates of the Rule, the sheer number of rule amendments to PUCT regulations will be a costly, time-consuming, and resource-intensive task. I believe that amending this many rules is an undertaking similar in scope to the rules adoption required in response to the implementation of retail electric competition in the ERCOT power region. Implementing all the rules needed for retail competition in the ERCOT power region took three years, from 1999-2002, and many of the rules required subsequent revisions. Given the complexity and scope of the Rule, I believe that completion of only the regulatory amendments necessary to implement the Rule will take several years.

90. A separate but related implementation issue will be the amending of existing market rules and adoption of new market rules by market operators like ERCOT, Inc. Because the Rule requires fundamental changes to the way electricity markets operate, ERCOT, Inc. will need to adopt or amend numerous market rules to mitigate the impacts resulting from the Rule. Additionally, ERCOT, Inc. will also need to adopt significant and costly information technology system changes to comply with the Rule.

91. Development and approval of a new market rule or an amendment to an existing market rule typically takes 5 to 12 months on a normal timeline or 2 to 4 months on an urgent timeline. Market rule changes may require changes to ERCOT, Inc. and market participant systems. Implementation of any necessary system changes resulting from a rule change typically takes an additional 9 to 18 months on a normal timeline or 8 to 12 months on an urgent timeline. However, depending on the complexity of the change, the timelines for both rule development and system implementation can vary. The above-discussed timelines do not include market participant appeals of protocol changes to the PUCT, which is permitted under PUCT rules. The appeal to the PUCT of a protocol adopted by ERCOT, Inc. can take anywhere from 5 to 15 months, depending on the complexity of the protocol that is being challenged. The above-discussed timelines also do not include the appeal of a PUCT decision in court, which can take several years.

92. Since compliance with the Rule will likely require substantial changes to ERCOT, Inc. market rules, development and approval of the rule changes and implementation of the necessary system changes will likely take a minimum of 14 months and could take significantly longer. These changes will be irreversible.

93. In sum, EPA has vastly underestimated the regulatory and electricity system changes needed to comply with the mandates of the Rule. Even if Texas begins implementing these changes immediately, there will not be enough time to thoughtfully determine the feasibility of these changes in time for the submission of a State Plan in either September 2016 or September 2018. The Rule requires Texas to fundamentally overhaul laws and regulations governing electricity in the State, and it mandates hasty changes to the ways Texas generates, transmits, and consumes electricity. Absent a stay, Texas will have no choice but to immediately undertake actions that will cause harm to its citizens and sovereignty. These harms will be permanent and irreversible, and they can be easily prevented with a stay pending litigation.

94. I declare, under penalty of perjury, that the foregoing is true and correct.

Executed on October 19, 2015.

Brian H. Lloyd

Brian H. Lloyd

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

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos.________

DECLARATION OF JIM MACY, DIRECTOR, NEBRASKA DEPARTMENT OF ENVIRONMENTAL QUALITY

I, Jim Macy, declare as follows:

1. I am the Director at the Nebraska Department of Environmental Quality ("NDEQ"). I have over 30 years of experience in the environmental field as a regulatory official in the State of Missouri, as a consultant, and now as the head of the State of Nebraska's environmental agency. As part of my duties, I am responsible for overseeing and supervising the agency in Nebraska with exclusive jurisdiction to act as the state air pollution control agency for all purposes of the Clean Air Act, as amended, 42 U.S.C. 7401 et seq., including development and administration of State Plans under Section 111(d) of the Clean Air Act. I have personal knowledge and experience to understand what steps that Nebraska has taken and will need to undertake in response to the EPA's final Section 111(d)

Rule: Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.

2. Based on my experience, I have determined that implementing the final Section 111(d) Rule will be a complicated and time-consuming endeavor. Without prior notice and an opportunity for the State to comment, EPA decided to make Nebraska's CO_2 emissions goal significantly more stringent in the final 111(d) Rule than it was in the draft 111(d) Rule. These changes will make Nebraska's task even more difficult.

3. The final Section 111(d) Rule is unlike any other Clean Air Act implementation undertaken by Nebraska. Specifically, the final Section 111(d) Rule's reliance on measures that require the reduction of demand for a particular source of energy—building blocks 2 and 3—are unprecedented for Nebraska and the NDEQ. Nebraska will be required to expend a large number of resources to design a State Plan that incorporates these building blocks.

4. NDEQ employees have already expended approximately 2000 hours on interpreting and preparing for the implementation of the final Section 111(d). During the proposal stage, the NDEQ reviewed the proposal, held multiple meetings with the affected utilities to understand potential impacts, met with the affected utilities in groups and individually, met with the Southwest Power Pool to understand how the final 111(d) rule would impact transmission, convened

discussions with industry and other interest groups, met with the Nebraska Energy Office, met with the Nebraska Power Review Board, participated in conference calls with EPA and other states to clarify understanding of the proposed rule, analyzed the proposal, and prepared comments.

5. Planning, designing, and implementing a State Plan to comply with the final Section 111(d) Rule will require substantial state resources. The NDEQ will need to partner with the Nebraska Energy Office and the Nebraska Power Review Board to implement the final Rule. This partnership will be unprecedented in Nebraska. The final 111(d) Rule requires that a State Plan be developed in a manner that goes through a public comment and public hearing process, which we anticipate could take as long as six months. The final Section 111(d) Rule gives Nebraska until September 6, 2016, to submit its State Plan. Extensions are available for two years for an individual state. Preparing and submitting a timely plan may require three dedicated staff members, additional contractors to facilitate meetings with stakeholders state-wide, and significant resources from other state agencies, stakeholders, and the Nebraska Legislature. There will inevitably be additional or redirected costs of implementation so it is difficult to estimate the total cost at this time.

5. If Nebraska chooses to adopt a multi-state approach to complying with the final Section 111(d) Rule, Nebraska will need to enter into either a

memorandum of understanding or agreement with the other States. Nebraska has experience in negotiating this type of agreement with other States, and it is anticipated that a significant amount of time will be required to negotiate and reach consensus on the content of such an agreement with other States.

6. The final 111(d) Rule may also require changes in Nebraska laws, which would require action by the Nebraska Legislature. The timetable for legislative changes is unknown.

7. Implementing a State Plan under the final 111(d) Rule will consume vital state resources, which would otherwise be devoted to addressing pressing issues of public concern.

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

Executed on October 16th, 2015.

Jim Macy
Director, Nebraska Department of
Environmental Quality

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

STATE OF WEST VIRGINIA,
STATE OF TEXAS, *et al.*,

Petitioners,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY,

Respondents.

Case Nos.

DECLARATION OF JEFF MCCLANAHAN

I, Jeff McClanahan, hereby declare as follows:

1. I am the Director of the Utilities Division of the Kansas Corporation Commission (KCC). The KCC regulates public utilities, common carriers, motor carriers, and oil and gas producers. Public utilities include local telephone, natural gas, and investor-owned electric service providers. As part of its duties, the KCC is responsible for ensuring that reliable and affordable energy is available and deliverable to Kansas citizens and businesses.

2. Based on my position, I have the personal knowledge and experience to understand what steps the State will need to undertake in response to the Environmental Protection Agency's (EPA's) Section 111(d) Rule, including the difficulties that will be encountered in attempting to comply with the Rule. In general, the Section 111(d) Rule will dramatically transform the way electric power will be generated, dispatched, and transmitted to consumers in the State of Kansas and throughout the United States.

3. Based on my work experience and position, I have determined that implementing the Section 111(d) Rule will be a complicated, time consuming, and expensive endeavor, which will require the expenditure of substantial State resources, immediately and over the next several years.

4. Kansas will need at least three years to conclude a stakeholder process to determine the least cost state plan which ensures electric reliability. This process will require:

a. Defining the options for compliance and evaluating these options in terms of least cost and reliability

b. The evaluation of these options will need to be done on an expanding geographical basis, beginning with the individual EGUs, then the individual utilities, next at a state level, and finally at a multi-state level. At each stage, the options will need to be tested using sophisticated dispatch models with varying assumption about fuel costs, O&M costs, potential carbon prices, population and economic growth in Kansas and its surrounding states, different infrastructure developments including electric generation, transmission, and distribution investments, and natural gas infrastructure investment, to safeguard that only robust options are considered. And finally, the options must be evaluated on both a Kansas only state plan and on a multi-state implementation plan.

c. The evaluation process will require the KCC to work with all the stakeholders to ensure that all of the feasible options are evaluated. Thus, the process will require the KCC, utilities, the Kansas Department of Health and Environment (KDHE), the Southwest Power Pool, and other affected groups to work together in a careful and efficient manner. This process will require expenditures on costly resources and entail several years of intensive study, consultation, and negotiation.

d. Once the Commission, KDHE, and the State Legislature have agreed on a plan for its jurisdictional utilities, KDHE must develop a compliance plan or plans for each of the utilities.

5. Based on my knowledge and experience, the Section 111(d) Rule represents an unprecedented infringement by the EPA on the traditional authority of Kansas to manage energy resources within our jurisdiction because the mandates of the Section 111(d) require KCC to undertake specific changes to how energy is generated, dispatched, and transmitted to consumers. The Section 111(d) Rule also disrupts the well-settled division of authority over electricity markets under the Federal Power Act, and raises significant uncertainty about the role of the Federal Energy Regulatory Commission (FERC) to ensure the reliability of electricity through the wholesale market. In determining the adequacy and reliability of its system, a state must balance various public interest concerns and technical considerations to maintain sufficient and efficient service at just and reasonable rates. The overarching technical and policy concern in this area is the appropriate generation mix to be employed by jurisdictional utilities. The Section 111(d) Rule severely invades a state's authority to make such determinations.

6. Absent a stay from this Court, compliance planning must begin immediately. The system-wide changes necessary for compliance must be gradual to preserve reliability of the electric grid. Because compliance is calculated based on a moving average, the longer Kansas waits to begin compliance, the more expensive and difficult it will be to meet the requirements of the Rule. In addition, the KCC estimates it will spend approximately $500,000 to $1,000,000 on consultants to aid in the analysis and development of a compliance plan. Any potential changes to EPA's Section 111(d) Rule resulting from court decisions, which will most likely take several

years to decide, will require additional analysis and modification of the initial plan developed in Kansas. This will result in significant additional costs and a waste of the State's resources.

7. Absent a stay from this Court, evaluation of specific compliance measures, such as new facilities or retirements, must also begin immediately. The lengthy application and approval process for utilities to construct, upgrade, or retire generation, transmission, and distribution facilities to comply with the Section 111(d) Rule, as well as the in-depth evaluation of public necessity and convenience for each facility, requires utilities to plan and submit applications for upgrades almost immediately after publication of the final Section 111(d) Rule in order to have equipment constructed, upgraded, or decommissioned before the compliance period begins in 2022.

8. Kansas will need to request an extension until 2018 in order to develop a reliable compliance plan at the lowest cost. EPA will then need six months to a year to approve the Kansas plan, resulting in a final approved plan in 2019. Given the three years (2019 to 2022) EPA is allowing for Kansas to construct or upgrade facilities with long construction times – five to seven years for transmission assets – the interim goals beginning in 2022 are unachievable. Further, the KCC expects billions in ratepayer costs to comply with this rule. Absent a stay from this court, Kansas utilities are at risk of investing money to comply with a plan under pending review. If the rule is not upheld, ratepayers will be obligated to pay for those initial investments plus any investments made to comply with a modified rule. Immediate compliance has the potential to be a significant and unnecessary waste of state and ratepayer funds.

9. Kansas stakeholders are currently meeting on a weekly basis to evaluate compliance options due to the unrealistic compliance deadlines set in the Section 111(d) Rule. The work being performed by all stakeholders includes analysis of the requirements in the Section 111(d)

Rule, development of timelines and due dates, evaluation of compliance options, estimation of compliance costs, and determination of risk regarding reliability of the bulk electric system for each option. Given the large number of stakeholders affected, hundreds of hours of time are being expended each week. The stakeholder efforts result in a significant cost of human resources and expense on a weekly basis, all in the hope of meeting unrealistic compliance deadlines.

10. In excess of $3 billion has been spent by Kansas utilities on environmental compliance projects for its coal-fired generation fleet, and these projects were approved by the EPA under state implementation plans (SIPs). The Section 111(d) Rule creates stranded utility/ratepayer investment because coal-fired units that were retrofit in compliance with EPA rules have not been excluded from the calculations in determining a CO_2 emissions goal. It is inherently unfair and extremely poor regulatory policy to require significant expenditures to reduce coal plant emissions and then change the regulatory paradigm to eliminate or significantly curtail coal-fired generation without regard to the useful remaining life of those Electric Generating Units (EGUs).

11. Decisions made for the sake of compliance with the Section 111(d) Rule immediately and over the next several years will be irreversible and will impact the electric grid for decades. System planning is typically based upon the 30-40 year expected lives of generation and transmission facilities. The decision to prematurely retire an electric generating unit could significantly impact system reliability and may unnecessarily increase customer's rates for decades to come.

12. The Section 111(d) Rule sets an emissions performance standard for the State of Kansas, rather than the specific affected EGUs. By doing so, the EPA has created a near

certainty that legally-troublesome cross-subsidies will occur between ratepayers of the various utilities in the state. The KCC can address cross-subsidy issues within the context of setting rates for one single utility. However, the EPA's state-wide emissions standard will create cross-subsidy issues between the customers of *separate utilities*. The KCC does not have statutory authority to allocate the costs associated with the Rule to all ratepayers in Kansas because the KCC does not regulate a large number of utilities. Therefore, if a non-jurisdictional utility does not agree to a compliance plan, the KCC would be forced to require jurisdictional utilities to take additional measures to meet the overall emissions guideline. This results in KCC jurisdictional ratepayers subsidizing the costs of compliance for non-jurisdictional ratepayers.

13. Kansas law (K.S.A. 66-104 and 66-104d) currently exempts the majority of municipal and cooperative utilities from regulation by the KCC. Because Kansas' state plan must be federally enforceable, it is possible that the deregulated municipal and cooperatives affected by the Section 111(d) Rule will need to become regulated again. Any change of state law and policy due to a federal mandate is difficult and uncertain and should not be undertaken unless all possible appeals have been addressed and the rule has become final post-litigation.

14. Absent a stay from this Court, if Kansas chooses to adopt a multi-state approach to comply with the Section 111(d) Rule, changes to rights and responsibilities of entities such as Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs") will be immediate and long lasting. If Kansas joins in a multi-state compliance approach, it is likely to take the form of credit trading or an induced carbon price through the RTO. The members of these organizations must follow a prescribed stakeholder process to effect the changes, and Kansas must agree to grant certain enforcement powers to those organizations. This will likely require a revision of K.S.A. 65-3031, which otherwise prohibits such changes. The

stakeholder process and any necessary institutional changes for the states included in the multi-state approach, the RTOs, and ISOs will need to be completed before a plan relying on those third parties can be submitted for approval to the EPA. Utilities require certainty of cost recovery when planning for large-scale infrastructure investments that have a useful life of 40 years or more. Adding institutional uncertainty to the already created increased price and investment uncertainty will make utility compliance even more problematic and could place affected utilities in an untenable position. These processes are lengthy, difficult to reverse once established, and will require immediate expenditure of resources over next calendar year.

I declare under penalty of perjury that the foregoing is correct. Executed on this 14TH day of OCTOBER, at Topeka, Kansas.

Jeff McClanahan

Jeff McClanahan

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

State of West Virginia, et al., Petitioners, **v.** **United States Environmental Protection Agency, et al.,** Respondents.	Case No. 15-1363 (and consolidated cases)

DECLARATION OF DOUGLAS L. McVAY, CHIEF, OFFICE OF AIR RESOURCES, RHODE ISLAND DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

I, Douglas L. McVay, declare:

1. This declaration is based on my personal knowledge. I am over the age of eighteen (18) years and suffer from no legal incapacity. I submit this declaration in support of the objections to the motions to stay filed in the above referenced matter.

2. I am the Chief of the Rhode Island Department of Environmental Management ("RIDEM"), Office of Air Resources. I have worked in Rhode Island's air pollution control program since 1977 in various capacities. I worked in the program as an Air Pollution Engineer from 1977 to 1979; as a Senior Air Pollution Control Engineer from 1979 to 1984; as a Principal Air Quality Engineer

from 1984 to 1992; as an Associate Supervising Sanitary Engineer from 1992 to 2008; and Chief from 2008 to date. Prior to becoming Chief in 2008, my work in those positions was exclusively with all aspects of regulating stationary sources of air pollution, including, but not limited to, inspections, permitting, writing regulations, emission testing and enforcement.

3. I have been Chief of the RIDEM Office of Air Resources since 2008. In that capacity, I am responsible for planning and administering a statewide program to preserve, protect and improve the air resources of the state and to formulate and administer a comprehensive program for air pollution control and to do related work as required.

4. The regulations to implement the Regional Greenhouse Gas Initiative and the Clean Power Plan in Rhode Island are/will be administered and enforced by the RIDEM Office of Air Resources, which I manage and direct. Staff that work under my direction will be responsible for developing Rhode Island's compliance plan for the Clean Power Plan. I also regularly participate in Agency Heads meetings of the Regional Greenhouse Gas Initiative ("RGGI"), which I describe in greater detail below.

5. The purpose of this declaration is to provide my understanding of the State of Rhode Island's readiness to comply with the administrative and procedural requirements of the United States Environmental Protection Agency's ("EPA")

final rules regarding greenhouse gas emissions from existing power plants under Section 111(d) of the Clean Air Act, published in the Federal Register at 80 Fed. Reg. 64,661 on October 23, 2015, and titled "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (the "Clean Power Plan").

6. The State of Rhode Island is concerned about the impacts of greenhouse gas emissions from the electric power sector, the single largest source of these emissions in the United States and the second largest source in Rhode Island. Rhode Island has recognized that there is a compelling need to reduce greenhouse gas emissions from the electric power sector to mitigate the harms from global climate change, including sea level rise; coastal and shoreline changes; increased severe weather events, flooding, storm surges, and coastal erosion; critical infrastructure vulnerability; and ecosystem, economic, and health impacts.

7. In an effort to address the impacts from global climate change Rhode Island enacted the Resilient Rhode Island Act of 2014–Climate Change Coordinating Council, R.I.G.L. § 42-6.2-1, *et seq*. (the "Resilient RI Act"). The purpose of the Resilient RI Act is to assess, integrate, and coordinate climate change efforts throughout state agencies to reduce greenhouse gas emissions, strengthen the resilience of communities, and prepare for the effects of climate

change, including, but not limited to, coordinating vulnerability assessments throughout state government.

8. The Resilient RI Act requires that a plan be produced that includes strategies, programs, and actions to meet targets for greenhouse gas emissions reductions in Rhode Island as follows:

(i) Ten percent (10%) below 1990 levels by 2020;

(ii) Forty-five percent (45%) below 1990 levels by 2035; and

(iii) Eighty percent (80%) below 1990 levels by 2050.

9. The State of Rhode Island strongly supports federal efforts to limit greenhouse gas emissions from the power sector. Federal action is essential given that only the federal government can set national guidelines and standards, which are necessary to maximize both emissions reductions and incentives for the development of cleaner sources of energy.

Clean Power Plan Rule

10. I have followed the development of the Clean Power Plan, including working with representatives of the Regional Greenhouse Gas Initiative states ("RGGI States") to provide information to EPA as it developed the proposed Clean Power Plan, including the RGGI States' comments in response to the pre-proposal opportunity to comment, and to prepare detailed comments on the proposed rule. (*See* December 2, 2013 Letter from RGGI States available at

http://rggi.org_States_111d_ Letter_Comments.pdf; November 5, 2014 Letter from RGGI States available at http://www.rggi.org/docs/PressReleases/PR110714_CPP_Joint_Comments.pdf; and December 12, 2014 Letter from RGGI States available at http://www.rggi.org/docs/PressReleases/PR120114_RGGI_SupplementalComments_CPP.pdf.

11. I participated in RIDEM's review of the Clean Power Plan, including preparation of RIDEM's December 1, 2014 comments to the EPA regarding the proposed Clean Power Plan.

12. I am familiar with the final Clean Power Plan. The rule establishes state goals for carbon dioxide (CO_2) emissions for reducing emissions at electric generating units. It also specifies guidelines for states to use in developing, submitting, and implementing state plans to achieve the rule's goals. In the final rule, the state goals were determined using subcategory-specific CO_2 emission performance rates that reflect the "best system of emissions reductions… adequately demonstrated" (BSER) from the power sector. In the final rule, state goals are in two forms: rate-based and mass-based CO_2 goals to provide states with flexibility in developing their plans, including utilizing allowance trading programs and other measures.

13. The Clean Power Plan requires that states submit compliance plans or initial submittals requesting an extension to EPA by September 6, 2016. States that are granted an extension must submit their final compliance plans by September 6, 2018. The Clean Power Plan also permits states to join together and submit joint compliance plans in lieu of state-specific plans.

14. The Clean Power Plan acknowledges, and provides mechanisms to credit, the State of Rhode Island's past, present, and future investments in renewable energy and energy efficiency. In particular, if the State elects to adopt a mass-based state plan, all of the State's low-carbon resources and demand reduction investments, whenever undertaken, will facilitate the State's overall achievement of Clean Power Plan goals.

15. The RIDEM also acknowledges that the Clean Power Plan provides incentives for early action, in the form of bonus emission reduction credits or carbon allowances, for renewable energy deployment and low-income energy efficiency programs that provide emission reductions in 2020 and 2021, before compliance requirements under Clean Power Plan state plans take effect.

16. The RIDEM also recognizes that the Clean Power Plan allows states *not* to submit a plan without any sanction or penalty, in which cases EPA will impose a federal plan. If a state elects not to submit a plan, a state will not have

any obligation to conduct planning, adopt legislation or regulations, or expend taxpayer resources under the Clean Power Plan.

17. The RIDEM understands that the Clean Power Plan seeks to reduce emissions from electric generating units and that the entities regulated under the Clean Power Plan are the owners and operators of electric generating units, not states themselves, state environmental or energy agencies, or other participants in the state's energy sector. In this regard, the Clean Power Plan is not dissimilar to other air emissions regulations applicable to electric generating units. The RIDEM further understands that there is no regulatory or funding sanction if a state does not submit an approvable plan to EPA under the Clean Power Plan regulations.

18. The State of Rhode Island has already begun its compliance planning efforts. As a RGGI participating state, Rhode Island has and will continue to participate in stakeholder outreach through RGGI-wide stakeholder meetings. The first of an on-going series of stakeholder meetings occurred on November 17, 2015 in New York City. Stakeholder meetings will be a combination of in-person meetings and meetings via webinar. In addition, written comments are accepted as well. The draft proposed schedule for stakeholder meetings can be found http://www.rggi.org/design/2016-program-review/rggi-meetings. The RIDEM will also schedule a state specific stakeholder workshop in the near future. The RIDEM will extend outreach to all interested parties including but not limited to

vulnerable, low income or minority communities. The RIDEM may use a combination of the following approaches for community engagement: post CPP related information and notices on the RIDEM website, RGGI page, local media (newspaper), social media tools (e.g. Twitter, Facebook), and utilize the RIDEM's Press & Communications Office. In addition, as a RGGI participating state, the RIDEM staff engage in weekly conference calls with RGGI counterparts in the region. These discussions are ongoing and relate to the compliance obligations of the RGGI states in respect to the Clean Power Plan and include topics such as modifications to the Carbon Dioxide Allowance Tracking system (COATS), possible changes to the RGGI Model Rule, and modeling requirements. These conversations are being held at both staff level Program Committee level as well as with the respective Agency Heads of RGGI.

19. As a result of the State of Rhode Island's research and planning on climate change and its work with EPA and other RGGI States, the RIDEM fully anticipates that it can meet the planning deadlines in the Clean Power Plan by filing an initial submission by September 6, 2016, and a final plan by September 6, 2018.

Regional Greenhouse Gas Initiative

20. RGGI is a market-based program to reduce greenhouse gas emissions from the electric power sector. RGGI is a cooperative effort among the

RGGI States of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

21. The program requires power plants to possess a tradable CO_2 allowance for each ton of CO_2 they emit. The program was developed under a Memorandum of Understanding signed by initial member state governors in 2005 and implemented by the RGGI States in 2009.

22. RGGI is grounded in each state's own statutory and regulatory authorities. Each state's laws and regulations establish "CO_2 Budget Trading Programs" that limit emissions of CO_2 from electric power plants, create CO_2 allowances, determine appropriate allowance allocations, and provide for participation in CO_2 allowance auctions. *See* R.I. GEN. LAWS §§ 42-17.1-2(19), 23-23, 23-82; R.I. CODE R. 25-4-46:46, 47:47.

23. Under contracts with the RGGI States, RGGI, Inc., a non-profit corporation, administers regional auctions to sell CO_2 allowances. States sell nearly all emission allowances through auctions and invest most of the proceeds—over $2.2 billion through September 2015—in energy efficiency, renewable energy, and other consumer benefit programs. *See* Press Release, CO_2 Allowances Sold for $6.02 in 29th RGGI Auction; $152 Million Raised for Reinvestment on RGGI's Seventh Anniversary, September 11, 2015, *at* http://www.rggi.org/docs/Auctions/29/PR091115_Auction29.pdf.

24. Collectively, the states' CO_2 Budget Trading Programs establish an annually declining cap on CO_2 emissions from the power sector within the RGGI States. The RGGI program, in conjunction with other state clean energy polices and other energy market factors, has helped the RGGI States reduce carbon dioxide emissions by approximately 40 percent since 2005.

2012 Program Review

25. The RGGI States completed a two-year comprehensive program review in 2012. Following the review, the states established a new regional CO_2 budget that lowered the cap on emissions to 91 million tons in 2014, a reduction of 45 percent from the original cap. Under the program changes, the cap will decline 2.5 percent each year from 2015 to 2020. To implement the newly lowered cap, the RGGI States then revised their own CO_2 Budget Trading Programs through their state-specific legislative and regulatory processes.

26. Using their own processes for revising their respective legal authorities, the RGGI States successfully adopted statutory and regulatory changes in time for the lower regional cap to be in place for 2014 regional auctions. In Rhode Island, for example, the state Department of Environmental Management adopted changes to the regulations governing the state's CO_2 Budget Trading Program in their Air Pollution Control Regulation Nos. 46 and 47, revised on December 25, 2013.

27. The RGGI States' successful 2012 program review demonstrated their ability to work together to set new goals for regional emissions reductions while timely amending their individual state programs to reflect those goals. *See* Press Release, RGGI States Make Major Cuts to Greenhouse Gas Emissions from Power Plants, Jan. 13, 2014, *at* http://www.rggi.org/docs/PressReleases/PR011314_AuctionNotice23.pdf.

RGGI States and the Clean Power Plan

28. In their comment letters on the proposed Clean Power Plan, the RGGI States offered their support of the rule's framework, which provides states with flexibility to craft plans to meet state-specific emissions targets. The RGGI States also lauded the provisions of the proposed rule encouraging states to work together to develop multi-state compliance plans. *See* RGGI States' Comments on Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (November 5, 2014); RGGI States' Supplemental Comments on Proposed Clean Power Plan (Dec. 1, 2014), referenced in paragraph 10 *supra*.

29. Under the final Clean Power Plan, states will begin demonstrating initial compliance by January 1, 2022, and states may set their own interim goals between 2022 and 2029. The RGGI States are working together to consider submitting one multi-state compliance plan or individual state plans that rely on

RGGI as a compliance mechanism. The RGGI States currently have a plan for completing this multi-state effort in a timeframe that will allow for timely submission of state plans. For example, as discussed in paragraph 18 above, the RGGI-wide stakeholder process is underway and will continue into at least the summer of 2016. Additional stakeholder meetings will be added as needed and Rhode Island will hold a state-specific community workshop as well. The RIDEM is also coordinating with other State agencies, including the Office of Energy Resources and the Division of Public Utilities in the planning process.

30. The State of Rhode Island has in place the necessary authorities and administrative procedures to assure timely compliance with federal Clean Air Act rules, including the Clean Power Plan. In this regard, Rhode Island has decades of experience complying with other federal Clean Air Act rules that require comprehensive state planning to achieve compliance, including state implementation plans to achieve the National Ambient Air Quality Standards for criteria air pollutants. *See* 40 C.F.R. Part 52, Subpart OO (Rhode Island).

31. The RIDEM routinely and effectively coordinates with the Rhode Island Office of Energy Resources, our state energy agency, on issues of shared interest, including the impact of federal environmental regulations on the State's regulated industries and the State's power sector in particular. As with prior federal environmental regulations, the RIDEM is prepared to coordinate its work

under the Clean Power Plan among the State agencies with implicated jurisdiction or interests.

32. The State of Rhode Island has a demonstrated track record of efficiently working with counterparts in other states to develop harmonized and/or coordinated regulatory programs that implicate multiple states, including membership in RGGI and in the Northeast States for Coordinated Air Use Management ("NESCAUM"), an association of air quality agencies in Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.

33. Based on the RGGI States' experience complying with federal Clean Air Act rules and their successful implementation of the RGGI program, I am confident that the RGGI States, including Rhode Island, are well equipped and will be able to comply with the state planning requirements of the Clean Power Plan in a timely fashion.

State Harms from a Stay of the Clean Power Plan

34. The State of Rhode Island has repeatedly sought to expedite EPA action to place federal limits on greenhouse gas emissions. These actions include pushing EPA to regulate Greenhouse gases (as a plaintiff in *MA v. EPA* (549 U.S. 497 (2007)); clarifying the federal government's role in Greenhouse Gas regulation (as a plaintiff in *AEP v. CT* (131 S.Ct. 2527 (2011)); supporting EPA in its

regulation of greenhouse gases (as an Intervenor in *UARG v. EPA* (573 U.S. ___ (2014)) and *Delta Construction v. EPA* (Nos. 11-1428, 11-1441, 12-1427 (D.C. Cir. petition for rehearing en banc denied Aug. 3, 2015)); and supporting EPA's proposed Clean Power Plan as an Intervenor in this action.

35. Staying the Clean Power Plan could delay long overdue reductions in emissions from the nation's power sector, which the State sees as essential to preventing the worst impacts of climate change. There is no guarantee that a stay will not result in postponements of the compliance deadlines in the Clean Power Plan even if the Plan is ultimately upheld. For example, in the recent litigation in this Court over EPA's Cross-State Air Pollution Rule, a rule that was eventually upheld after a remand from the Supreme Court, a stay issued at the outset of the litigation resulted in EPA postponing the compliance deadlines by three years. Any such postponements would delay compliance actions that states and/or private actors would otherwise have taken, resulting in emissions that will stay in the atmosphere for many years to come and aggravating the climate change harms to the State.

36. A stay will interfere with the State of Rhode Island's activities under other federal and state air programs and with State clean energy planning. As part of the 2012 Program Review (described in paragraphs 25-27 above), the RGGI States committed to commencing a comprehensive program review no later than

2016 to consider program successes, impacts, and other program design elements. The RGGI States will use the regional 2016 Program Review as an opportunity to receive comments from stakeholders and experts on potential program changes in pursuit of compliance with the Clean Power Plan. RGGI's Program Review would be adversely affected by the uncertainty associated with a stay of the Clean Power Plan. A stay in the Clean Power Plan would also increase the uncertainties of federal involvement and complicate the State's future climate change mitigation planning activities.

I declare under penalty of perjury that, to the best of my knowledge and belief, the foregoing is true and correct.

Executed on this 1st day of December, 2015.

/s/ Douglas L. McVay___________________
Douglas L. McVay, Chief
Office of Air Resources
Rhode Island Department of Environmental
Management

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

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos.

DECLARATION OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

I, Richard S. Mroz, declare as follows:

1. I am the President of the New Jersey Board of Public Utilities (BPU). The BPU is the agency empowered by the laws of the State of New Jersey with authority over regulated utilities to ensure that New Jersey ratepayers receive safe, adequate, and proper service at just and reasonable rates. The BPU also has authority, as the State Energy Office, over the administration of federally funded energy programs for the State. As President of the BPU, I serve as the BPU's presiding and chief administrative officer as well as a cabinet member in New Jersey. I also act as

the chairperson for the State's Energy Master Plan (EMP) Committee. The EMP is the State's strategic plan for the use, management, and development of energy. One of the overarching goals of the EMP is to drive down the cost of energy for all New Jersey ratepayers.

2. Based on my position and experience, I have the personal knowledge to understand the potential impacts of EPA's Section 111(d) Rule (Rule) on energy markets in New Jersey, including its likely impact on ratepayers and the broader State economy.

3. Absent a stay, to implement the Rule, New Jersey needs to develop its State plan immediately. This will require the State of New Jersey to make several significant legislative and regulatory changes to implement the actions necessary for compliance with the Rule. The decisions that New Jersey is forced to make now will influence the energy grid in New Jersey and influence the behavior of energy producers, transmitters, and consumers for the foreseeable future. Those impacts will be immediate, and will be impossible to undo if the Rule is later invalidated unless a stay is issued now.

4. In 1999, New Jersey deregulated its energy regulatory structure, limiting the BPU's jurisdiction to the regulation of electric and gas distribution companies. As a result, the BPU no longer exercises authority over electric generation facilities.

a. Implementation of the Rule could require the construction of new power plants to achieve compliance. If that is the case, New Jersey would need to enact new legislation to vest the BPU with the authority to direct that construction.

b. Implementation of the Rule requires authority to direct the actions of existing generators to achieve compliance. The BPU does not currently have this authority. The Legislature would have to grant the BPU this additional authority by new law.

c. Implementation of the Rule requires electric generating units to enter into purchase power agreements or contracts. The BPU also lacks the authority to require these under New Jersey's current legislative scheme. Thus, it is impossible for New Jersey to implement the Rule absent new legislation.

5. The Rule provides for a trading program that includes energy efficiency. Under the existing legislative scheme, the BPU lacks the authority to develop such a program. New Jersey's Legislature would need to enact new legislation. In addition, the BPU would need to draft, propose, and adopt new regulations to implement such a trading program.

6. Implementation of the Rule would also require amendments to New Jersey's existing statutes and regulations governing its renewable portfolio standard.

For instance, New Jersey's legislation and accompanying regulations define renewable energy certificates and solar renewable energy certificates. A renewable energy or solar renewable energy certificate represents all of the environmental benefits or attributes of one megawatt hour of generation from either a Class I or Class II renewable energy or solar energy facility. By contrast, the Rule provides for an emission reduction credit for only CO2, which is but one of the environmental benefits in the New Jersey renewable energy or solar renewable energy certificate. Therefore, New Jersey's statutes and regulations would need to be revised because the same megawatt hour could not satisfy both requirements. This process would require action by the Legislature as well as subsequent action by the BPU to draft, propose, and adopt new regulations.

7. New Jersey is a member of PJM Interconnection, LLC (PJM), the federally-authorized regional transmission organization (RTO) responsible for operating and managing competitive wholesale electricity markets and the interstate transmission system within the 13-state (plus the District of Columbia) regional electric power grid. PJM's operational objective is the insurance of electric system reliability. PJM is under the exclusive jurisdiction of the Federal Energy Regulatory Commission (FERC).

a. Under the Rule, states have the option to enter into agreements among themselves without regard for a state's particular RTO or accounting for

FERC's authority over the RTO. This creates uncertainty and jurisdictional conflicts between the states' authority and that of FERC, likely leading to implementation delays or more that would make immediate compliance impossible.

b. In addition, implementation of energy efficiency measures related to the electric transmission system that may be necessary to achieve compliance with the Rule may be exclusively regulated by FERC and under the operational control of PJM, which has the obligation of ensuring the reliability of the electricity grid. Without new legislation, the BPU cannot immediately order the implementation of such measures to ensure compliance with the Rule.

8. Implementation of the Rule will irreparably harm New Jersey's ratepayers, who have funded and continue to fund investments directed by PJM, FERC, and the BPU, and who will be obligated to make additional investments to comply with the Rule. If no stay is granted and the Rule is later invalidated, New Jersey's ratepayers will bear the cost of implementing the Rule with no concomitant benefit and no mechanism to refund investments made toward compliance with the invalidated rule.

a. PJM determines transmission system upgrades necessary to ensure continued electric system reliability; PJM-identified transmission upgrades, along with the cost allocation of such upgrades, are subject to FERC approval. FERC-approved transmission costs are, in turn, reflected in the price of electricity borne by New Jersey's ratepayers. If certain electric transmission system upgrades are later deemed unnecessary for compliance with the Rule, and these upgrades do not receive credit under the Rule, New Jersey ratepayers will still be forced to pay for the costs associated with the construction of those transmission system upgrades, in addition to any new construction that may be required under the Rule, with no economic recourse.

b. From 2001 to 2012, $3.27 billion was invested in renewable energy and energy efficiency in New Jersey, the costs of which were borne by New Jersey's ratepayers. The Rule in its current form disallows credit for renewable energy sources and increases in nuclear power plant capacity developed before 2013, effectively penalizing New Jersey for its leadership in this area. New Jersey's ratepayers will be irreparably harmed because they will not receive financial benefit for their investments in energy efficiency and renewable energy.

9. New Jersey's ratepayers are already saddled with electricity prices that are among the highest in the nation. EPA has acknowledged that implementation of

the Rule will initially increase these electricity prices. Without a stay, New Jersey's efforts to comply with the Rule will harm the State's economy.

a. Higher electricity prices will significantly impact New Jersey's ratepayers, particularly low income ratepayers, by reducing the resources they have available to purchase other goods and services, thereby lowering their standard of living.

b. Higher electricity prices will negatively impact the New Jersey economy by reducing profitability for investment and job growth and will lead to a decline in New Jersey's energy-intensive manufacturing and commercial services sectors, with significant attendant job losses.

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

Executed this 16th day of October, 2015.

Richard S. Mroz, President
New Jersey Board of Public Utilities

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

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ______

DECLARATION OF ELLEN NOWAK, CHAIR, WISCONSIN PUBLIC SERVICE COMMISSION

I, Ellen Nowak, declare as follows:

1. I am the Chair of the Public Service Commission of Wisconsin ("PSCW"). I have been employed at the PSCW for four years. As part of my duties, I have authority to monitor, track, and interact with stakeholders[1] and

[1] Stakeholders include regulated utilities, merchant-owned EGUs, municipal utilities, utility cooperatives, environmental groups, industry groups, residential and small business representatives, Midcontinent Independent System Operator, Inc. ("MISO"), Midwest Renewable Energy Tracking System ("M-RETS"), and representatives from other entities interested in or impacted by state and federal environmental rules impacting public utilities.

regulators on the development and implementation of state and federal environmental rules impacting public utilities.

2. Immediately after the release of EPA's proposed *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units*, 79 Fed. Reg. 34, 830 (June 18, 2014) ("Proposed 111(d) Rule"), the PSCW acted to determine what steps Wisconsin would need to take in response. The PSCW's review determined that, in general, the Proposed 111(d) Rule would dramatically transform the way electric power would be generated and transmitted to consumers in Wisconsin and throughout the United States. The Proposed 111(d) Rule would, at the very least, require the construction of new power plants and associated infrastructure, the updating or decommissioning of existing power plants that are not fully depreciated, and the reduction in overall energy consumption by every single current and future consumer of electric power. In short, the Proposed 111(d) Rule would transform the American economy.

3. Based on my work experience and position, I have determined that implementing the Proposed 111(d) Rule would be a complicated, time consuming, and expensive endeavor, which would require the expenditure of substantial State resources, immediately and over the next calendar year. The final version of the Proposed 111(d) Rule ("Final Rule") was released on August 4, 2015 and is expected to be published in the Federal Register in mid to late October, 2015.

Though the Final Rule is different than the proposal, it will not reduce the amount of resources necessary for planning and implementation in the immediate future.

4. Significant PSCW resources have already been invested to understand and evaluate the Proposed and Final 111(d) Rule. PSCW employees have spent significant time understanding the proposal and preparing for implementation, including outreach to all Wisconsin stakeholders, organizing stakeholder meetings and listening sessions, participating in regional collaboratives such as Midcontinent States Environmental and Energy Regulators and the Midwest Power Sector Collaborative with other states and industry participants, attending EPA listening sessions and conference calls, and in-depth analysis of the impact of the 111(d) Rule on the state and regional systems.

5. In order to help inform our comments on the Proposed 111(d) Rule, and to determine the viability of a regional plan when compared to a state plan, the PSCW expended substantial resources modeling likely compliance scenarios. The purpose of this model was to forecast the cost of the changes in the Wisconsin utility market that would be necessary to comply with the Proposed 111(d) Rule. With input from stakeholders, engineers from the PSCW collaborated with MISO to build a model using the "Electric Generation Expansion Analysis System ("EGEAS"). Several model runs were completed, analyzed, and presented with

our comments to the EPA. We also presented the modeling results in several different conferences with Wisconsin stakeholders.

6. The PSCW has begun its comprehensive review of the Final Rule and its effects on everyone who pays an electric bill in Wisconsin. The Final Rule is significantly different, which means, absent a stay, PSCW staff must undertake another intensive investigation into the requirements of the Final Rule and start over with evaluation of compliance paths and modeling. Similarly, if litigation changes the Final Rule, much of the time and energy invested in understanding and compliance planning for the Final Rule will have been wasted. Wisconsin will be forced to choose between following through with compliance of the un-altered Final Rule, or starting over with a third investigation and compliance analysis.

7. Based on my knowledge and experience in analyzing the Proposed and Final 111(d) Rules, the Final Rule represents an intrusion by the EPA on the traditional authority of Wisconsin to manage energy resources within our jurisdiction. The Final Rule also raises uncertainty about the role of the Federal Energy Regulatory Commission to ensure the reliability of electricity through the wholesale market. Without clarity on the roles of different state and federal agencies, the PSCW is at risk of violating any number of rules, order, and mandates. The Final Rule should be stayed until these jurisdictional questions are fully adjudicated.

8. Absent a stay from this Court, Wisconsin will continue to invest resources in compliance planning. Evaluation of compliance options has already begun. The system-wide changes necessary for compliance will require collaboration among other state agencies, stakeholders and other states, and resulting compliance measures must be implemented gradually to preserve reliability of the electric grid. Because there are interim limits that must be achieved, the longer Wisconsin waits to begin planning, the more expensive and difficult it will be to meet the requirements of the Final Rule.

9. Absent a stay from this court, significant resources may be wasted on continued evaluation of specific compliance measures, such as the construction of new facilities or retirements of existing facilities. In order to have facilities constructed, upgraded, or decommissioned before the compliance period begins in 2022, the lengthy application, in-depth evaluation, and approval process for utilities to construct, upgrade, or retire facilities to comply with the Final Rule requires utilities to plan and submit applications very soon after publication of the Final Rule, and even before an EPA-approved State or Multi-State plan.

10. For example, the Final Rule will likely require one or more new natural gas plants in Wisconsin. A new natural gas combined cycle plant takes at least five years from application to operations. Before submitting an application for a new generation resource that requires a certificate of public convenience and

necessity (CPCN) from the PSCW pursuant to Wis. Stat. § 196.491(3), a utility conducts a needs assessment, site selection, and pre-engineering work. This work can take more than a year to complete. In addition, the utility works with the transmission owner and the Regional Transmission Operator, MISO, to get in the generator queue. Then, the utility submits an application for a CPCN, including full environmental review and analysis of need by the PSCW, which requires a contested case hearing. This process can take up to one year to complete. After the CPCN is issued, it takes another three years for final engineering and construction before the plant can go into service. Waiting until litigation is complete to begin implementing the measures required in the plan would make it impossible for Wisconsin to meet the 2022 goal, and even more costly and difficult to meet the final 2030 goal.

11. Ideally, a utility would wait until the state plan was approved by the EPA before planning for future resources, but even if a utility starts planning today, it is possible that the new plant would not be commissioned before the 2022 initial interim deadline. The interim goals will also force utilities to act more quickly than the usual 30 to 40 year planning timeframe, which could preclude building new generation that requires an even longer planning schedule, such as nuclear plants. Even with an extension of time for the interim goal to 2022, if the 2030 goal remains in place during litigation, Wisconsin utilities will have no

choice but to begin implementing compliance measures immediately, subject to the PSCW approval.

12. Not only does commissioning plants include a lengthy approval process, but so does decommissioning plants. Utilities cannot simply shutter a plant's production. Utilities must apply to the MISO for permission to decommission a plant. MISO then evaluates the entire multi-state system for reliability concerns, and can, in fact, decline to allow a plant permission to decommission. MISO has to ensure that enough base load resources are available to fill the void of a decommissioned plant, which may mean importing or constructing new sources. This process lasts at least 26 weeks from application to decommissioning. If Wisconsin's plan is not approved until September of 2019, there may not be enough time before the 2022 interim goal to follow the established retirement procedure. Absent a stay, plants may be prematurely retired, which is difficult, expensive, and in some cases impossible, to reverse.

13. State goals in the Final Rule were calculated based on a significantly higher reliance on natural gas and renewable generation than in the Proposed 111(d) Rule. Compliance with the Final Rule is likely to materially increase the cost of electricity by forcing Wisconsin to move immediately toward reliance on a limited number of fuel sources. There are significant risks associated with this type of system-wide transformation, which is likely to begin occurring in the very

near future, unless the Final Rule is stayed. Wisconsin's electric generation system relies on multiple fuel sources: coal, natural gas, nuclear, biomass, biogas, wind, solar, fuel oil, and international and domestic hydropower. This balanced portfolio approach reduces the risk that electric rates or reliability will be harmed by the price volatility or unavailability of any single fuel source. For example, if the price of natural gas increases sharply, then Wisconsin's system can rely more heavily on other sources, keeping the retail prices stable. The modeling performed by the PSCW on the Proposed 111(d) Rule indicates that in order to comply with Final Rule, utilities will become much more heavily reliant on natural gas as base load generation. This means the overall generation portfolio will be heavily dependent upon one fuel source, creating a high risk for increased system fuel cost as the market for that particular fuel source changes. In other words, if natural gas becomes scarce due to price fluctuations or an interruption in the supply, then generators, and subsequently ratepayers, will experience significant price spikes. The possibility of a significant long-term increase in the price of natural gas due to increased regulation of production methods like fracking could further inflate prices. Given the timelines imposed by the Final Rule, it would be unreasonable for the PSCW to wait until litigation is complete to begin working with utilities on specific compliance measures that move the generation toward heavy reliance on natural gas, which will directly and irreversibly impact the cost of electricity in Wisconsin.

14. The immediate and sweeping changes to the generation fleet could also result in significant decreases in reliability. As noted, PSCW modeling on the Proposed 111(d) Rule showed heavy reliance on natural gas plants in Wisconsin. The output of most renewable sources cannot be easily controlled or dispatched, and is dependent upon the weather conditions. Currently, gas plants that can ramp production up and down very quickly and are used to respond to load variances caused by more intermittent renewable energy resources. For example, if the wind dies or the sun is blocked by clouds, the natural gas plants are used to quickly ramp up energy production to make up for the production loss from the renewable sources, maintaining a balance of supply and demand on the electric grid. Other generation types, such as nuclear and coal facilities, are not able to ramp energy production up and down fast enough to respond to the rapid changes resulting from renewable resources. However, the Final Rule encourages natural gas plants to operate at capacities of 75% or higher, leaving very little capacity that is free to respond to rapid demand changes on the grid. The amount and intensity of these rapid changes will only be exasperated by the increase of renewable resources brought onto the system for 111(d) compliance. The inability to use the natural gas fleet to respond to these rapid supply-demand changes could result in system

overloads, equipment failures, forced shutdown of customer energy supply, and significant reliability concerns. If the Final Rule is not stayed, there will be limited time to study and prevent potential reliability failures. The immediate large scale changes to the electric system required by the Final Rule before 2022 could reduce reliability.

15. In response to concerns about reliability raised by states, generators and FERC, among others, the Final Rule contains a reliability "safety valve" that gives states a 90-day period to exceed carbon limits during emergencies. The eligibility and process for obtaining such relief is cumbersome and time consuming. EPA Air Chief Janet McCabe has publicly stated that approval of such requests for regulatory relief will be a rarity. Thus, the "safety valve" will not be able to address the reliability concerns previously noted regarding the inability to use the natural gas fleet to respond to rapid supply-demand changes caused by more intermittent renewable energy resources.

16. Changes made for the sake of compliance with the Final Rule immediately and over the next calendar year will be irreversible and will impact the electric grid for decades. If system planning begins and capital is committed, and then the Final Rule is invalidated by a court, investors, taxpayers, and ratepayers will all suffer the financial consequences.

17. In addition, implementation of the Final Rule may require legislative changes which could alter the daily operation of utilities. Specifically, the Final Rule allows compliance measures outside of the physical location and control of electric generating units, such as end-use energy efficiency (reduced energy use by electricity consumers), demand response (usage changes according to instantaneous market and load-profile changes), increased distributed generation (such as small residential renewable installations), and increased reliance on renewable generation. For example, a utility can encourage, through financial incentives or otherwise, the use of energy efficiency or demand response, but the utility has no ability to force customers to reduce usage. Parameters for utilities to encourage their customers to rely on these control measures are currently set in state statute. Wis. Stat. § 196.374(3)(b)2 only allows the PSCW to require utilities to spend 1.2 percent of their annual operating revenues on energy efficiency programs. The PSCW does not have authority to force a larger investment in energy efficiency without a statutory change, and will be unable to rely on energy efficiency as a compliance option without these statutory changes.

18. Moreover, higher rates may encourage more customers to install distributed generation on their own property over which the utility has no control. The utility must still provide backup generation to these customers, which will result in a higher cost system. Wisconsin may have to immediately set in motion

the chain of events, including statutory changes, larger investment in customer-side behavior, and further rate restructuring, in order for these compliance options to contribute the amount of carbon reduction EPA expects from them by 2030. This chain of events would be difficult to reverse, and should not begin before there is certainty about the legality of the Final Rule.

19. If Wisconsin joins in a multi-state compliance approach, it's likely to take the form of credit trading or an induced carbon price through the RTO, which will require participation of third party actors, such as the MISO or M-RETS. The members of those organizations must follow a prescribed stakeholder process to effect the changes, and Wisconsin must agree to grant certain enforcement powers to those organizations. The stakeholder process and any necessary institutional changes for entities like MISO and M-RETS will likely need to be completed before a plan relying on those third parties can be submitted for approval to the EPA. These processes are lengthy and may require immediate attention if the Final Rule is not stayed during litigation.

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

Executed on October 15, 2015

Ellen E. Nowak
Ellen Nowak

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

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ________

DECLARATION OF TODD PARFITT

I, Todd Parfitt, hereby declare as follows:

1. I am the Director of the Wyoming Department of Environmental Quality. I received a bachelor of science in natural resources and a master of public administration with an emphasis in environmental policy from The Ohio State University. As part of my duties, I am responsible for overseeing the Department's regulatory programs, including its implementation of federal Clean Air Act regulations.

2. I have been employed by the Wyoming Department of Environmental Quality for twenty-one years. During that time, I have overseen the implementation of numerous facets of the Department's regulatory programs. I have served as

the Director for three years. I also served as Deputy Director for seven years, Administrator of the Industrial Siting Division for seven years, Interim Administrator of the Abandoned Mine Lands Division two different times, and manager of the Department's Clean Water Act pollution discharge permitting program for seven years. I also spent four years working in the Department's Resource Conservation and Recovery Act programs related to hazardous and solid waste and leaking underground storage tanks. In these positions, I regularly reviewed federal and state regulatory program requirements. I also worked with the Wyoming legislature on multiple matters related to the Department's regulatory programs. As a result of my experience, I am well versed in state implementation of environmental regulatory programs.

3. Based on my professional experience, education, and study of the Environmental Protection Agency's ("EPA") finalized but not yet published *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* ("Final Rule"), and supporting technical documents, I have the personal knowledge to understand what steps Wyoming will likely need to undertake in response to the rule, including preparing a state plan. Under the Final Rule, Wyoming must submit a plan, or a request

for an extension request along with an identification of a final approach under consideration and progress made to date, to the EPA by September 6, 2016.

4. Based on my evaluations of the EPA's requirements for Wyoming in the Final Rule, I have determined that implementing the rule presents a complicated endeavor necessitating immediate investment of significant Department resources. This will result in taking resources from other Department programs including Clean Air Act initiatives and commitments. Specifically, creating a plan of the type envisioned under the Final Rule would require years of effort that will be particularly complicated for at least the following reasons.

5. There are significant and substantial changes from the proposed rule to the Final Rule that we have not had time to fully identify or understand at this early stage of Final Rule review. These significant and substantial changes include but are not limited to: a new method for calculating state emission targets, resulting in Wyoming's target goal to change from a 19% reduction to a 44% reduction of CO2 emissions by the year 2030; a substantial change in the methodology in calculating state target rates involving a complicated regional formula not seen by Wyoming prior to the EPA's release of the prepublication version of the Final Rule; and methodology for development

of uniform emission rates for existing Electric Generating Units that are more stringent than emission rates for new Electric Generating Units.

6. The Department is in the process of reviewing the 1560 pages of the pre-publication version of the Final Plan, the 755 page federal plan, and the hundreds of pages of technical supporting documents, which only became available to Wyoming on August 3, 2015. Considering the voluminous nature of these documents and the significant and substantial changes from the proposed rule to the Final Rule, this review process will take staff several months to fully comprehend if and how Wyoming can comply with the Final Rule.

7. The Final Rule relies on "outside the fence" control measures, which include increased utilization of renewable energy and natural gas. Such "controls" are unlike any other Clean Air Act requirement the Department implements. Implementing and enforcing these unusual control measures would require the Department to coordinate with other agencies, including the Wyoming Public Service Commission, which regulates public utilities in Wyoming, and the Wyoming Game and Fish Department, which, along with federal agencies, manage wildlife in Wyoming's renewable energy development corridors. Preparing a plan to meet the requirements of the Final Rule would require considerable collaboration and buy-in to align the differing missions of these

agencies with the EPA's rule. For example, to meet the EPA's goal, utilities in Wyoming would likely have to retire coal-fired power plants. To do that, consultation would have to occur with the Public Service Commission, to evaluate the financial impacts that plant shutdowns would have on electricity consumers under Wyoming's system of public utility regulation. Plant shutdowns would also warrant the Department's consultation with public utility regulators in other states whose citizens pay for Wyoming-generated electricity.

8. Second, and related to the former, the Final Rule requires the construction and operation of new renewable electricity projects to meet the State's goal. Specifically, the Final Rule identifies wind energy and solar energy as the highest potential renewable resources and supposes that nearly tens of thousands of square miles are available to develop these new energy projects. Many of these lands are located within sensitive areas and habitat for certain wildlife, such as greater sage grouse. As a result, developing a plan to generate more wind and/or solar energy consistent with the proposed rule would require intensive coordination with State Game and Fish Agencies, which oversee sage grouse and other sensitive wildlife conservation efforts. Pursuant to Wyoming Executive Order, Wyoming agencies shall "prioritize the maintenance and enhancement of Greater Sage-Grouse habitats and

populations," may authorize new development in core habitat "only when it can be demonstrated to the satisfaction of the permitting agency, and based upon the recommendations made by the Wyoming Game and Fish Department, that the activity will avoid negative impacts to Greater sage-grouse" and must consult with the Game and Fish Department before taking any action that could impact sage grouse. Wyo. Exec. Order 2015-4, at ¶¶ 5, 6 (July 29, 2015). The Order expressly provides that wind energy development "is not recommended in Greater sage-grouse Core Population Areas[.]" *Id.* at Attachment B, p.14. Deploying enough new wind energy to comply with the EPA's proposed Rule also would require consultation and negotiation with the private parties that own the vast majority of the Wyoming lands suitable for wind energy projects. Lines to transmit wind energy generated by those projects will almost certainly have to cross federal lands, thereby implicating the regulatory interests of federal land managers, and requiring compliance with the National Environmental Policy Act. Coordinating these differing regulatory and private interests quickly enough to develop a state plan on the EPA's proposed timeline could only be possible with an immediate re-allocation of a substantial portion of the Department's resources and commitments from federal agencies outside the control of the Department.

9. Wyoming is a net-exporter of energy from both fossil-fuel and renewable sources. Because Wyoming delivers energy to eleven different states, from California to Minnesota, complying with the Final Rule would most likely require Wyoming to enter into one, if not several, multi-state or regional agreements with states that consume power generated in Wyoming. Negotiating and executing those agreements in time to submit a plan on the EPA's timeline would require a significant investment of Department resources. The effort will be complicated by the fact that other states with which Wyoming will likely have to collaborate are located in different EPA regions than Wyoming, which will in turn require plan approvals from different EPA regional offices.

10. Creating a plan that conforms to the Final Rule will require the Wyoming legislature to act. Neither the Department nor any other Wyoming state agency likely has authority to require the unconventional controls on which the EPA's rule relies. For example, the Department does not have the authority to require the construction and utilization of renewable electricity generating projects. Wyoming's legislature meets only once per year and for no more than a total of sixty days every two years, unless the Governor calls for a special session. Wyoming's legislative process typically involves multiple hearings and, therefore, does not produce new law overnight. Even with immediate efforts

from the Department, obtaining the legislative authorization necessary to develop a plan that complies with the EPA's rule on the EPA's proposed timeline will be practically impossible.

11. Developing a plan to comply with the Final Rule will require the Department to recruit new resources, which is further complicated by the recent statewide hiring freeze necessitated by lower than projected revenues. In some cases, the rule implicates subjects outside the Department's normal area of air pollution control expertise, such as reliability of electricity availability and delivery. In other cases, the rule would create significant new workloads, for example, negotiating and administering complex multi-state and regional emissions allocation agreements and facilitating interagency coordination. Hiring new staff implicates the Department's budget, which the legislature must approve every two years, and may, as a result, also require additional legislative action. To prepare a state plan to comply with the Final Rule on the EPA's timeline, the Department would have to make these resource decisions before having had the opportunity to fully review the significant and substantial changes in the Final Rule or having had the opportunity to review and comment on the proposed Federal Plan Requirements.

12. As a practical matter, Wyoming now must begin expending substantial resources in order to attempt to comply with the September 6, 2016 deadline

for state plan submission contained in the Final Rule. This expenditure of resources will need to include consultation with Wyoming energy producers and consumers of Wyoming-produced energy, coordination with multiple states, state agencies and federal land managers, passing new state legislation, promulgating new regulations, and conducting public outreach.

13. Wyoming has already expended resources as a direct result of the proposed and Final Rule. As of October 13, 2015 the Department has dedicated over 1,850 employee hours to evaluating the EPA's proposed and Final Rule and developing ideas on how to craft a compliant state plan. Eight different members of the Department's program-level staff, including more than ten percent of the air quality program employees, have dedicated a total of employee hours working on the EPA's proposed 111(d) Rule since its publication. Those staff were pulled from their normal responsibilities, which include implementing the Department's normal Clean Air Act programs, such as Prevention of Significant Deterioration and Title V. I have personally worked over 400 hours on the proposed rule and Final Rule. In sum, the EPA's proposed rule and Final Rule have already consumed considerable limited Department resources that would otherwise be dedicated to other regulatory efforts. These initial investments of Department resources represent only the tip of the iceberg.

14. Collectively, the Department's efforts have been dedicated to: (1) meeting with the Wyoming Public Service Commission and the electricity generators (2) meeting with Wyoming's elected representatives and other Wyoming regulatory agencies; (3) meeting with regulators from other states, including through the Environmental Council of States, Western Regional Air Partnership, the Western States Air Resources Council, the Air & Waste Management Association, the National Governor's Association, and the Center for New Energy Environment; (4) participating in webinars hosted by the EPA, the Association of Air Pollution Control Agencies, and the National Association of Clean Air Agencies; (5) travelling to and attending the EPA's public hearings on the rule; and (6) researching and evaluating the rule internally. All of these efforts have been necessary to comprehend the bases for the proposed 111(d) rule, the prospects for interstate and regional cooperation, and the feasibility of crafting a Wyoming plan to meet the requirements of the rule.

15. The Department expects to take further steps in the coming months as a direct result of the Final Rule. The Department will continue to confer with the Wyoming Public Service Commission, electricity generators, other state agencies, states that receive electricity produced in Wyoming, and the general public. The Department will also continue to dedicate internal staff resources

to evaluating the practical, technical and economic implications of creating a state plan to meet the requirements of the rule. Those efforts will require continued investments of Department resources that would otherwise support other priorities.

16. If this Court holds that the EPA now lacks authority to regulate power plants under Section 111(d) of the Clean Air Act, Wyoming will immediately halt entirely the above-described expenditures on the Final Rule.

I declare under penalty of perjury that the foregoing is correct. Executed on this 19th day of October, 2015, at Cheyenne, Wyoming.

Todd Parfitt
Director
Wyoming Department of Environmental Quality

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

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ______

I, Leonard K. Peters, hereby declare as follows:

1. I am the Secretary of the Commonwealth of Kentucky's Energy and Environment Cabinet. I have been employed by the Commonwealth of Kentucky in this capacity for more than seven years. As part of my duties, I am responsible for programs related to the implementation of the provisions of the Clean Air Act.

2. Based on my position, I have the personal knowledge and experience to understand what steps the State will likely need to undertake in response to EPA's proposed final Clean Power Plan, which was released in a prepublication version on August 3, 2015, by EPA ("Clean Power Plan"),

including preparing a state plan consistent with Section 111(d). Under that section, the State must submit an initial plan to the Environmental Protection Agency ("EPA") by September 6, 2016, absent special circumstances.

3. The prepublication version of the Clean Power Plan contains three distinct parts: (a) The final version of the rules for new, modified and reconstructed electric generation sources under Section 111(b); (b) The final version of the rule for existing electric generating sources under Section 111(d); and, (c) The proposed federal plan for implementation in those states which do not submit a state plan or fail to win approval of their plan from EPA.

4. The final version of the rule for new sources under section 111(b) sets a standard for new coal-fired units of 1,400 lbs CO_2/MWh. Currently, the best performing units can only achieve approximately 1,800 lbs CO_2/MWh for coal-fired boilers creating a situation where no new coal-fired generation can be built absent any post-combustion CO_2 removal.

5. The section 111(b) rule sets a standard that is not technically feasible with existing control technologies. The rule continues to rely on carbon capture and storage as a means of reducing CO_2 emissions beyond what power plant emission control technology could achieve. This is inappropriate because the technology is not commercially available at the scale necessary to achieve

the standard. The captured CO_2 can only be stored in geological strata suitable for permanent sequestration.

6. The rule dealing with existing sources under section 111(d) was proposed on June 2, 2014, and was published in the Federal Register on June 18, 2014. The voluminous rule, some 1700+ pages, required significant staff time within the Cabinet to dissect and analyze. The state fleet-wide average target for Kentucky was set at 1,763 lbs CO_2/MWh, meaning that Kentucky's fleet of existing coal-fired boilers, currently averaging 2,166 lbs CO_2/MWh (based on 2012 data), had to reduce its CO_2 emissions by 18.6 percent. It appeared EPA had produced a draft rule that considered variations among states' economies, energy profiles, and potential for bringing on low-carbon sources, and had set individual state targets based on those criteria.

7. The proposed rule also allowed states to convert the emissions target rate into a mass emission target expressed in tons of CO_2 reductions. This meant that Kentucky would have to reduce its 2012 emissions of 93 million tons of CO_2 from coal and natural gas units, to a 2030 target of 77 million tons.

8. The final version of the section 111(d) rule clearly demonstrates that EPA reversed course and abandoned its state-by-state approach in calculating emission reduction targets. Instead, EPA calculated targets based on three

electric transmission grid regions—the Eastern Interconnect, the Western Interconnect, and the Electric Reliability Council of Texas (ERCOT). This is a significant and unexpected departure from the proposed rule. The final rule did not provide a rational explanation for the selection of regional interconnections over other available alternatives.

9. EPA applied a complicated formula utilizing projected efficiency upgrades to the EGUs, the expected potential for renewable energy development within the regions, and future natural gas combined cycle (NGCC) development to set separate national rate targets for coal-fired and NGCC generation. The targets, 1,305 lbs CO_2/MWh for coal and 771 lbs CO_2/MWh for NGCC, were then used to derive state-specific targets. EPA also set equivalent mass emission reduction standards for each state.

10. Kentucky's allowable rate is 27 percent more stringent under the final section 111(d) rule than under the proposed rule — the most significant change of any state when the final rule is compared with the proposed rule. Further, Kentucky's emission reduction obligation from the 2012 baseline increased from 18.6 percent to 31 percent, a 67 percent greater required reduction.

11. The EPA's methodology for calculating renewable energy potential is completely different from the methodology in the proposed rule. The EPA

selectively chose a high wind development year—2012—and projected that as the "potential" growth for renewable energy in Kentucky's region. Congress provided temporary tax credits for renewable energy development which accounted for the sharp increase in wind energy projects in 2012. Thus, the EPA acted arbitrary in using that figure to project the renewable energy potential for states.

12. The infrastructure is not in place for renewable energy to be dispatched to Kentucky. Presuming renewable energy is made available from distant states to Kentucky, transmission lines must be in place that may go through several other states.

13. The rule should be withdrawn and reopened for comments based on the multiple components of the final rule that were not a logical outgrowth of the proposed rule. The final rule is a totally different rule from the proposed rule, and Kentucky was not provided adequate notice to submit comments on those components.

I declare under penalty of perjury that the foregoing is correct. Executed on this 22nd day of 2015, at Frankfort, Kentucky.

L K Peters

Leonard K. Peters

Commonwealth of Kentucky)
)
County of Franklin)

Subscribed and sworn to before me by Leonard K. Peters on this the 22nd day of October, 2015.

Vicki M. Craycraft

NOTARY PUBLIC
STATE AT LARGE

My Commission Expires:

May 19, 2018

298A

DECLARATION OF SETH SCHWARTZ

I, Seth Schwartz, declare as follows:

INTRODUCTION

1. My name is Seth Schwartz, and I am the President of Energy Ventures Analysis, Inc. ("EVA"). Previously, I filed a declaration in support of the National Mining Association ("NMA") Motion for Stay of the Clean Power Plan ("CPP") to describe the irreparable harm which the coal industry, coal miners, and states and communities dependent on coal production will suffer if the Court does not grant NMA's motion. I have now been retained by the NMA to provide a declaration in reply to the assertions made by the U.S. Environmental Protection Agency ("EPA") in its Opposition to Motions to Stay the Final Rule, in particular to the declarations of Mr. Reid P. Harvey ("Harvey") and Mr. Kevin P. Culligan, both of EPA ("Culligan").

2. I will address two subjects: (a) the assertions by Mr. Culligan that the CPP merely continues what he believes is an underlying "market trend" that will lead to increased retirements of coal plants even without the CPP and (b) the assertions by Mr. Harvey that the IPM model predictions that the CPP will cause specific units to retire as early as 2016 are not reliable.

EPA UNDERSTATES THE IMPACT OF THE RULE BY MISCHARACTERIZING WHAT WOULD HAPPEN WITHOUT IT

3. EPA's claim that an ongoing "trend" has been and will continue to be responsible for the retirement of coal-fired generating capacity, and that the CPP will merely continue that trend, is demonstrably incorrect. The recent retirements cited by EPA are not the result of an ongoing trend reflecting the "market-driven cost advantages" of gas and renewable generation. Instead, the retirement of coal units has been primarily due to the costs imposed by other recent EPA regulations. Now that the power industry has absorbed the cost of the EPA rules (by investing in emission controls at coal-fired plants), the remaining coal units can continue to operate economically, absent the CPP.

4. EPA attempts to minimize the impact of the CPP by claiming that the CPP simply "builds upon the existing direction of the power industry" and "is consistent with prevailing trends in the energy sector towards more renewable and gas-fired generation", which "are due largely to falling prices for renewables and gas-fired generation".[1] EPA claims that "significant reductions in coal-fired generation would occur even in the Rule's absence"[2] and will be replaced by natural gas, renewable energy and reduced electricity demand. Culligan asserts that, "The recent and projected trends show a continued increase in capacity and generation

[1] EPA Response at 18.
[2] Id.

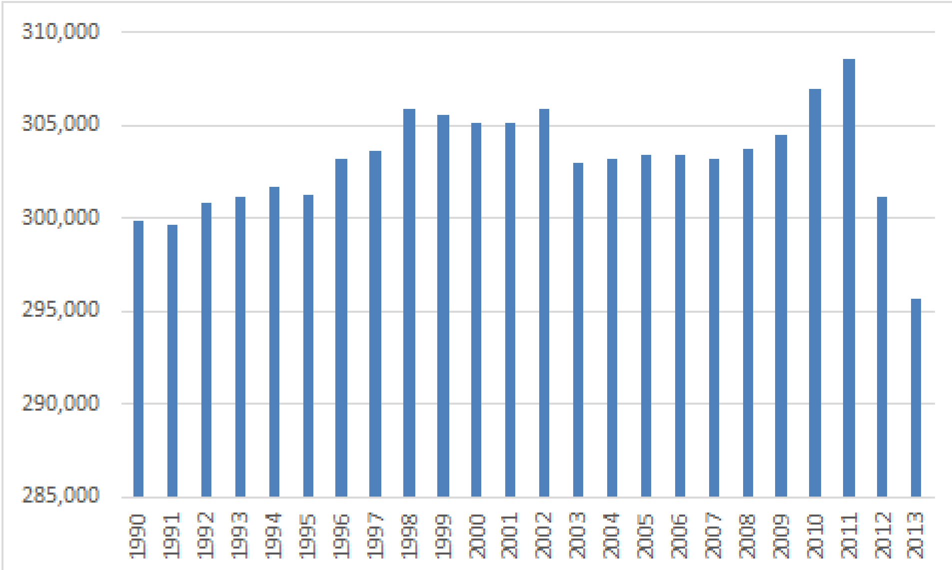
from natural gas and renewable energy, and corresponding decreases from coal. Principal reasons for these trends are market-driven cost advantages of natural gas and renewable energy vis-à-vis coal, an aging coal fleet, and reduced electricity demand."[3] To support the claim of a "trend" to retire existing coal-fired power plants, Culligan states: "For over a decade coal's share of total U.S. generating capacity has been declining, while capacity from natural gas and renewables has increased."[4]

A. There Is No Long-Term Trend Towards Coal Retirements, Only a Short-Term Trend Caused by EPA Rules.

5. In fact, while coal's *share* may have been declining for over a decade, coal's *total capacity increased* through 2011, when it reached an all-time high, as shown from the U.S. Department of Energy's Energy Information Agency ("EIA") data on Exhibit 1. The decline in coal's generating capacity did not start until 2012.

[3] Culligan declaration at 3.
[4] Id at 4.

Exhibit 1: Total Coal Generating Capacity 1990 – 2013 (Summer MW)[5]



The *share* of capacity from coal declined simply because the new power plant construction was mostly natural gas, wind and a small amount of solar, as shown on Exhibit 2. While a huge amount (over 175,000 MW) of new natural gas capacity was added from 1998 to 2004, this did not result in the retirement of any significant amount of coal capacity. As shown on Exhibit 3, less than 2,000 MW of coal-fired capacity was retired in any year prior to 2012 (under 1% of the capacity in place in any year), but large amounts of coal capacity have been retired in every year since then in order to comply with EPA rules.

[5] Total net summer generating capacity for the electric power sector (electric utilities and independent power producers). This is less capacity than shown in EPA's RIA Table 2-1 (RIA at 2-3) because EPA used nameplate capacity (which is greater than summer) and included industrial and commercial power plants, which are not regulated under the CPP. Source: EIA existing capacity by energy source annual data from Form EIA-860 available at http://www.eia.gov/electricity/data.cfm#gencapacity.

Exhibit 2: Generating Capacity by Source 1990 – 2013 (Summer MW)[6]

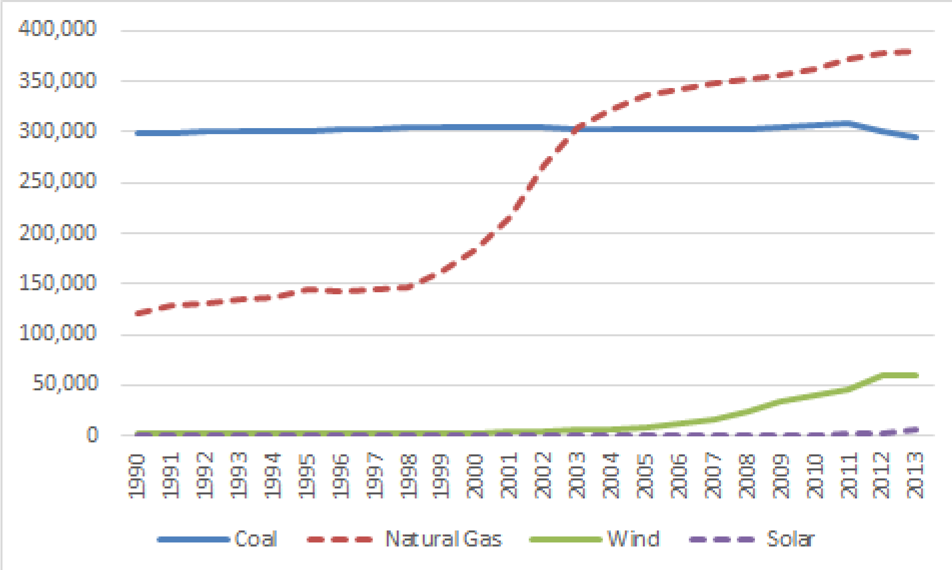
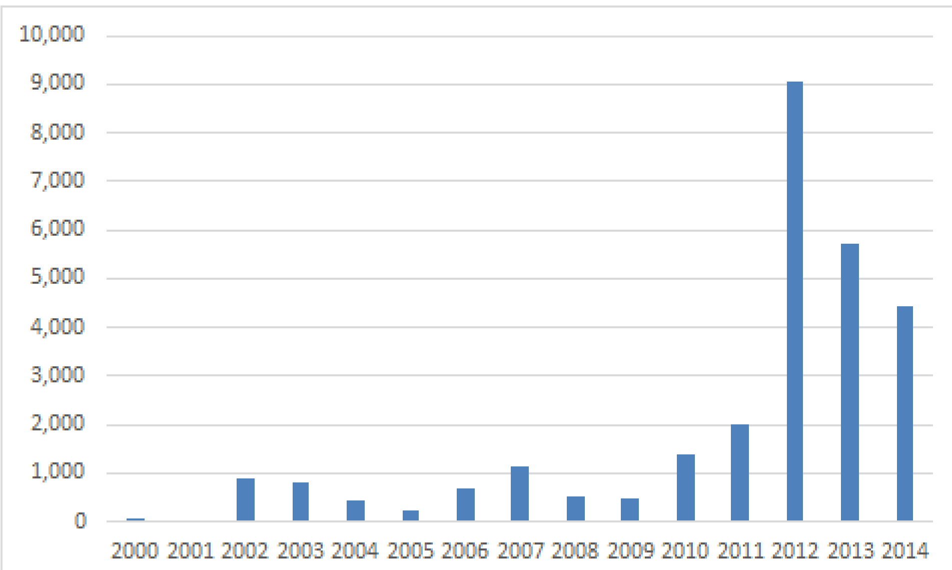


Exhibit 3: Coal Capacity Retirements 2000 – 2014 (Summer MW)[7]



---

[6] Id. Capacity from nuclear, hydro, petroleum and other minor sources not shown for clarity. Nuclear and hydro were essentially flat over this period, while petroleum fell.

[7] Retired coal capacity for electric utility and independent power producers (does not include plants converted from coal to gas). Source: 2014 Form EIA-860 Table 3.1 Generator_Y2014 available at http://www.eia.gov/electricity/data/eia860/.

6. EPA attributes the reasons for the recent decline in coal-fired capacity and generation to the price of natural gas,[8] the aging of the coal fleet,[9] and slow growth in electricity demand.[10] Missing from EPA's list of "drivers" of coal plant retirements is the primary cause – the plethora of new EPA regulations requiring existing coal plants to make large capital investments or close, particularly the Mercury and Air Toxics Standards ("MATS") rule but also others as detailed in my report.[11]

B. Low Natural Gas Prices Are Not Causing Coal Retirements.

7. EPA blames "a sustained drop in natural gas prices in the years preceding the first compliance year for MATS (i.e., 2015)"[12] for the retirement of coal-fired capacity, rather than the MATS rule. While natural gas prices did fall in 2012 from 2011, the decline was not to unusually low levels. Gas prices in 2012 were still higher than the average price of natural gas throughout the 1990's, as shown on Exhibit 4. However, coal plants did not retire in any significant quantities throughout that decade of low gas prices. The massive retirement of coal plants began in 2012,

---

[8] "A main driver of these trends has been the continued decline in the price of natural gas." Culligan at 10.

[9] "In addition to these reductions in natural gas price, a second reason for these trends is that as the coal-fired fleet ages, more and more coal-fired power plants are retiring." Culligan at 10.

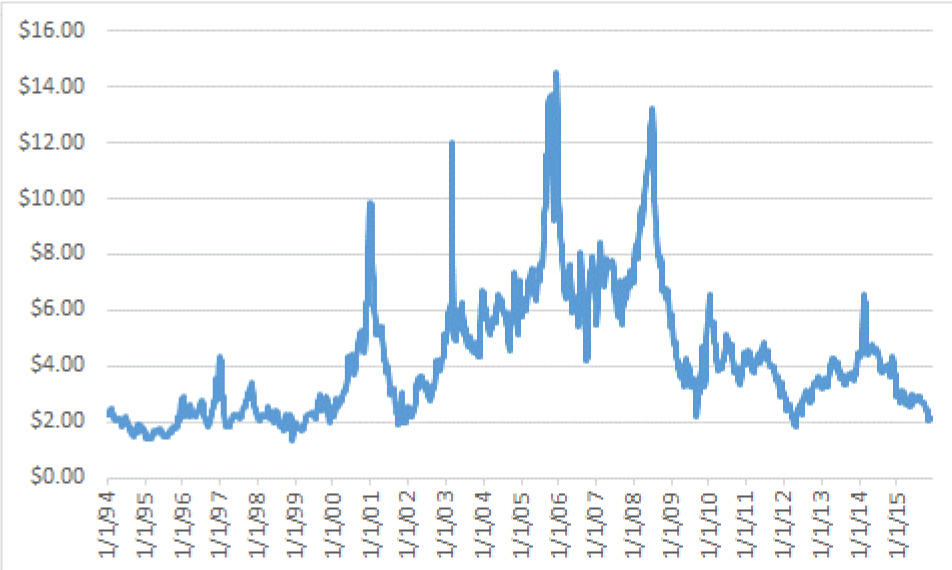
[10] "A third reason for the trend away from coal is the overall slowed growth in electricity demand." Culligan at 11.

[11] Schwartz Report at 63.

[12] Harvey at 31.

coinciding with the MATS rule, not the decline in gas prices. Natural gas prices recovered in 2013 and 2014, yet coal plants continued to retire in these years also.

Exhibit 4: Henry Hub Weekly Spot Natural Gas Price ($/mmBtu)[13]



In the period 2012 – 2015, coal plants did not retire because of the lower price of natural gas (which was no lower than it had been for most of the years 2009 – 2011 or the years 1994 – 2000 and 2002 – 2003). They retired because EPA forced these plants to either close or invest substantial capital in order to keep operating (primarily under MATS, but also other regulations described in my report). It is true that had natural gas prices stayed above $5.00 per million Btu, as they had been for most of the period from 2003 to 2008, more coal plants would likely have invested capital rather than retire, but the amount and timing of the

[13] Source: EIA at http://www.eia.gov/dnav/ng/ng_pri_fut_s1_w.htm.

massive wave of coal retirements from 2012 to 2015 was directly related to the new MATS rule, not the price of natural gas.

C. There Is No "Market" Trend Towards More Renewable Resources.

8. Similarly, the growth in power generation from non-hydro renewable energy (primarily wind and solar, but also biomass and geothermal) was not the result of "market-driven cost advantages of … renewable energy vis-à-vis coal"[14] but instead were the direct result of massive federal subsidies to promote construction of these facilities. These subsidies are scheduled to expire under federal law (phasing out through 2018 for wind and 2021 for solar under the recent spending legislation). Without these subsidies, the "trend" to build renewable generation will not continue, but the CPP will force the construction of these plants to replace coal. EPA projects that the rate of growth of renewables under the CPP will be much greater than the "trend", with generation tripling from 145 GWh in 2012 to 427 GWh in 2030.[15]

9. EIA quantified the amount of federal subsidies for energy production and consumption for fiscal year 2013, updating an earlier report covering fiscal year 2010.[16] EIA calculated that the annual subsidies provided to renewable electric generation in fiscal year 2013 were *$13.2 billion*, up from $8.6 billion in fiscal year

---

[14] Culligan at 3.
[15] EVA Report at 29.
[16] U.S. EIA, "Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2013", March 2015 at http://www.eia.gov/analysis/requests/subsidy/.

2010.[17] Even this amount is understated, as EIA calculated the cost of outlays (money spent in the fiscal year), not obligations (commitments made under multi-year grants and credits made during the fiscal year).[18] To put this into perspective, the total delivered cost of all coal purchased for electric generation during calendar year 2014 was $38.6 billion, yet generation from coal was almost six times larger than the total non-hydro renewable generation.[19]

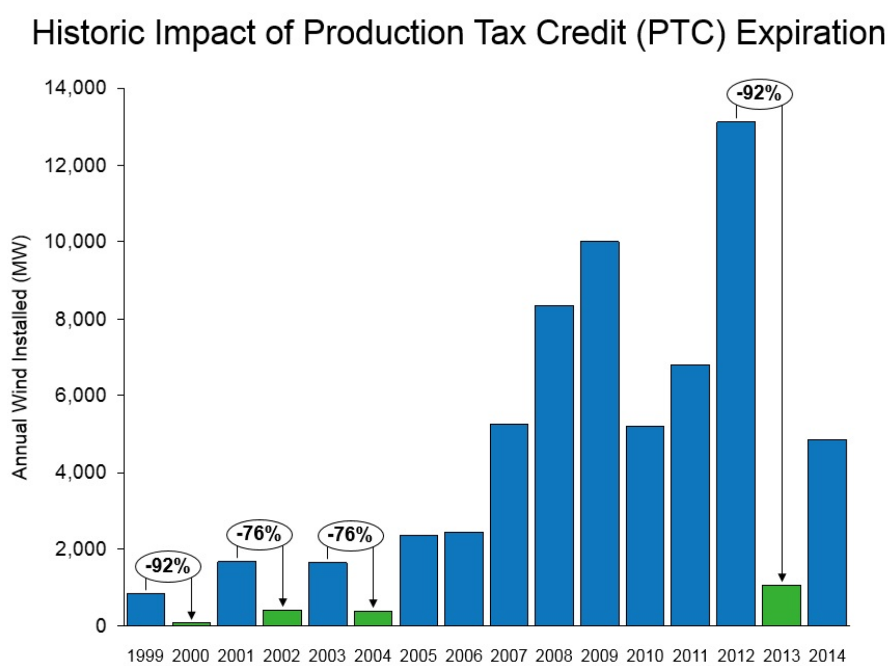
10. The primary sources of federal subsidies for renewable power generation are the Production Tax Credit ("PTC"), which was equal to $23 per megawatt-hour in 2013, and the investment tax credit ("ITC"), which was equal to 30% of the total investment. The PTC pays this subsidy for power sales in the first 10 years of operations. The PTC was originally enacted as part of the Energy Policy Act of 1992, originally was scheduled to expire in 1999, and has been expanded and extended several times since then, including in the Energy Policy Act of 2005 and the American Recovery and Reinvestment Act of 2009 ("ARRA"). Under the ARRA, the PTC was scheduled to expire for projects not completed by the end of 2012, which caused a boom of new wind projects to come on line during 2012. The PTC was again extended for wind projects in service by the end of 2016. The

[17] Id. Table ES2.

[18] Id. at xi.

[19] EIA, "Electric Power Monthly, March 2015", Tables 4.1 and ES1.B.

American Wind Energy Association ("AWEA")[20] acknowledges on its website that investment in new wind energy projects has come to a virtual halt every time the PTC has faced expiration prior to its extension by the federal government: "The PTC/ITC must be extended as soon as possible for as long as possible to prevent wind power from *falling off a cliff* like it has done in previous years when the policy was allowed to expire."[21] (emphasis added) AWEA's chart shows how wind power capacity additions have fallen by 76% - 92% in the year after the previous expiration of the PTC.[22]



[20] One of the "Advanced Energy Associations" which submitted a response in opposition to motion to stay the Rule.
[21] AWEA, Federal Production Tax Credit for wind energy at http://www.awea.org/Advocacy/Content.aspx?ItemNumber=797.
[22] Id.

11. Similarly, the solar energy industry is almost wholly supported by the ITC. The ITC for commercial and residential solar energy projects was temporarily increased from 10% to 30% of the capital costs in the Energy Policy Act of 2005.[23] Federal subsidies for new solar electric energy production exploded from $1.1 billion in FY 2010 to $5.3 billion in FY 2013.[24] The Solar Energy Industries Association ("SEIA", another member of the "Advanced Energy Associations" which submitted a response in opposition to motion to stay the Rule) describes the ITC as "the solar industry's most important public policy"[25] and advocates an extension of the ITC beyond 2016. SEIA provides its analysis of the impact of the expiration of the ITC stating: "If the ITC expires at the end of 2016, installed **solar capacity is expected to fall by nearly 8 gigawatts (GW) from 2016 – 2017**. Solar project levels would plummet from 11.2 GW in 2016 to 3.2 GW in 2017 – the lowest annual level since 2012."[26] (Emphasis in original.)

---

[23] EIA "Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2013", March 2015 at 18.
[24] Id., Table ES2.
[25] Solar Energy Industries Association, "Solar ITC Impact Analysis, How an Extension of the Investment Tax Credit Would Affect the Solar Industry" at http://www.seia.org/policy/finance-tax/solar-investment-tax-credit.
[26] Ibid.

D. There Is No Trend, Market or Otherwise, Towards An Absolute Reduction in Electric Consumption.

12. EPA also states, "A third reason for the trend away from coal is the overall slowed growth in electricity demand."[27] At least for this reason EPA acknowledged the role of federal programs, including the Energy Policy Act of 2005, the Energy Independence and Security Act of 2007 and the 2009 federal economic stimulus bill (ARRA).[28] EIA quantified the federal expenditures under these programs to be $4.4 billion in FY 2010, declining to $2.6 billion in FY 2013.[29] Most of these subsidies are scheduled to expire under current federal law.[30] But even with these subsidies, even EPA concedes that "U.S. electricity demand continues to increase",[31] not decline as EPA projects will be the impact of the Rule.

E. The Age of Coal Plants Is Not Causing Retirements.

13. EPA also asserts that coal-fired power plants will retire because they will be getting older by 2030.[32] While it is true by definition that existing coal plants will be older in 2030 than they were in 2012, EPA presents no evidence that this will cause existing coal plants to retire other than saying that the average age of coal plants in 2030 will be 60 years, which is older than the average age (55) of coal plants which

[27] Culligan at 11.
[28] Id.
[29] EIA "Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2013", March 2015, Table 8.
[30] Id. at 23.
[31] Culligan at 13.
[32] Id at 3, 11 and 15.

have already retired.[33] However, the coal plants which have already retired did so primarily to avoid the capital cost to invest in new emission controls required by EPA rules, not because of age. The remaining coal-fired plants still in operation have already invested to comply with existing EPA regulations. Coal-fired power plants have continued to operate efficiently at 60 years of age and can continue to operate with regular maintenance and capital investment to comply with new EPA regulations. For example, the large Kyger Creek and Clifty Creek power plants were both built in 1955 (60 years ago), but operate at capacity factors of 61% and 56% in 2014, respectively, similar to the 60% average for the entire coal fleet. The owners of these plants recently made massive investments in new emissions controls in 2012 and 2013 to comply with EPA's fine particulate (CAIR and CSAPR) and mercury (MATS) regulations, financed with bonds which mature through 2040, when the plants will be *85 years old*.[34] However, the CPP will require coal-fired plants to retire, as that is the only way to reduce carbon dioxide emissions.

F. EIA Is Not Forecasting Significant Post-MATS Coal Retirements.

14. In fact, EIA projects that coal plants will *not* retire in the future in significant amounts due to age or any other factor absent the impact of the CPP. The

[33] Id. at 15.

[34] Ohio Valley Electric Corporation, "Annual Report 2014", available at http://ovec.com/index.php.

following is taken from EIA's latest comprehensive industry assessment, Annual Energy Outlook 2015 ("AEO 2015").

EIA AEO 2015 Forecast of Coal-Fired EGUs Without the CPP[35]

2012	2016	2018	2020	2025	2030
305 GW	266 GW	261 GW	260 GW	257 GW	257 GW

As can be seen, EIA's figures show that, commencing with the adoption of MATS in 2012 and largely ending with the termination of the MATS compliance period in 2016, about 40 GW of coal capacity has retired or will do so shortly.[36] These units could not bear the significant costs of installing emissions-control equipment that MATS imposed as a condition to continued operation. But the remaining fleet, more than 260 GW, did make the necessary investments based on the expectation that they will be able to amortize those costs by operating into the indefinite future. EIA projects no trend towards the retirement of a significant number of coal plants post-MATS, absent the CPP.

15. As shown in my report,[37] EPA manufactured a trend toward increased coal retirements by manipulating its base case—the power sector without the CPP—by making a number of arbitrary assumptions that would cause the model to retire coal plants. These assumptions rejected projections made by the EIA, in favor of EPA's own forecasts, including lower natural gas prices, higher coal prices, and

[35] *See* EVA Report at 22, Exh. 11.
[36] Id.
[37] EVA Report at 17.

lower renewable generation costs.[38] All of this had the effect of increasing the number of coal plant retirements (even without the CPP), including a very large number that the model would project to retire (in the base case) in 2016, even though the owners of these units have not announced any such retirements.

16. But, it must be emphasized, even with EPA's IPM assumed base case retirements, its modeling results project that, by 2030, the Rule will still have a significant impact on coal, causing coal-fired generation to decline from 1,466 terawatt-hours ("TWh") under its base case to just 1,131 TWh under the rate-based policy case.[39] In its response to the stay motions, EPA attempts to minimize this impact by describing this reduction as "*only* 5.4% less than projected without the Rule"[40] (since coal generation would comprise 32.8% of all generation in the base case, and comprise 27.4% of all generation with the policy case). But as EPA's RIA notes, a reduction from 32.8% to 27.4% is **a reduction of 23%**, not 5.4%.[41]

G. My Testimony Was Not Inconsistent.

17. Contrary to EPA's claims, it is not inconsistent for me to criticize EPA's base case modeling results for over-projecting retirements, while accepting EPA's projection of the number of retirements in the policy case. It is not that I claim the model is "trigger-happy" in the base case and "gun-shy" in the policy case, as Harvey

[38] Harvey at 29 asserts that EPA does its own modeling of natural gas and coal supply, resulting in lower gas and higher coal prices than EIA, both critical in IPM modeling.
[39] RIA at 3-27, Table 3-11.
[40] EPA Response at 18.
[41] RIA at 3-27, Table 3-11.

suggests;[42] rather, it is simply a case of EPA's assumptions having the effect of moving retirements from the policy case to the base case. In other words, it is precisely the over-prediction of retirements in the base case that results in an under-prediction of retirements attributable to the policy case by comparison, even though the total number of retirements under the policy case must be essentially correct in order to comply with the emission limit in the CPP.

H. The Rule Is Causing Harm to Workers and Communities.

18. The imminent decline in coal generation due to early retirement will harm an industry and communities which are already reeling from the impacts of the decline in coal demand due to MATS and other factors. Culligan acknowledges that there are fewer active coal mines due to "reduced investment in the coal industry", in part due to "regulatory and permitting challenges", which "preceded the Rule".[43] However, he does not recognize how many more mines will close due to the CPP and how the industry and its employees are affected by mine closures. In 2014 and 2015, several of the largest coal companies filed bankruptcy as well as many smaller producers. Most of the remaining large companies have seen their stock prices collapse and are in a precarious financial condition. The imminent impacts of the CPP are likely to force more bankruptcies. The employees and communities which support the coal industry have suffered under current

---

[42] Harvey at ¶46.
[43] Culligan at 7.

conditions and can ill afford another blow in 2016. Since MATS was promulgated, national employment in coal mining has fallen by 27% from 2011 to 2015 (24,000 jobs lost), with the largest declines in the Appalachian states where coal is the lifeblood of the economy (West Virginia down 30%, Virginia down 40% and Kentucky down 46%).[44] Some of the highest unemployment rates in the country are in counties in the heart of the Appalachian coal fields (Logan, Mingo and McDowell Counties, West Virginia all have unemployment rates over 10% in October 2015).[45]

EPA CANNOT DISCOUNT ITS OWN MODEL'S PROJECTION THAT COAL RETIREMENTS WILL HAPPEN IN 2016 DUE TO THE CPP

19. As I showed in my report, EPA's IPM model projected that the CPP will cause the retirement of 53 specific coal-fired units in 2016 (or 2017) and another 3 units in 2018, totaling 18,116 MW.[46] Mr. Harvey claims that the model's 2016 results should not be "over-interpreted,"[47] but EPA cannot discount its model's findings, for several reasons: (a) EPA has high confidence in the predictive power of the model, having used the model to design major elements of the CPP; (b) Mr.

---

[44] Mine Safety and Health Administration, Mine Injury and Worktime Reports, December 2011 and September 2015 at http://www.msha.gov/ACCINJ/accinj.htm.
[45] Bureau of Labor Statistics unemployment rates by county http://www.bls.gov/lau/
[46] See EVA Report at 63. By combining 2016 and 2017 into one "model year", these units may retire either at the beginning of 2016 or the beginning of 2017. These retirements are over and above another 182 coal units which EPA projected would retire in its base case. Had EPA not exaggerated the base case retirements, many of these units would be retired under the policy case instead.
[47] Harvey at ¶23.

Harvey's reasons for denigrating the predictive power of the model are unpersuasive; and (c) EPA has already relied on IPM's prediction that the CPP would cause specific 2016 unit retirements to design a recently proposed new regulation.

A. EPA Used the Model to Design the CPP.

20. EPA obviously has high confidence in the model as a forecasting tool as it has used the model in numerous rulemakings and has repeatedly declared the model to be reliable. For instance, in its Regulatory Impact Assessment for the CPP (pp. 3-1 – 3-2), EPA states that

> The Integrated Planning Model (IPM), developed by ICF Consulting, is a state-of-the-art, peer-reviewed, dynamic linear programming model that can be used to project power sector behavior under future business-as-usual conditions and examine prospective air pollution control policies throughout the contiguous United States for the entire electric power system.
>
> ***
>
> EPA has used IPM for over two decades to better understand power sector behavior under future business-as-usual conditions and to evaluate the economic and emission impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible. EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM.

21. EPA, moreover, used IPM not just to predict the impacts of the CPP, but to craft the rule itself. As Harvey noted, EPA used the model to design the BSER itself, specifically building blocks 2 and 3. *See* Harvey at ¶16, n.3. For block 2, EPA

used the model to determine that it is feasible to run natural gas units at a 75% capacity factor and therefore that coal plants could feasibly shift generation to natural gas units up to that amount.[48] For block 3, as EPA said, "The IPM scenarios support building block 3 generation levels in two ways - by apportioning the national-level generation totals calculated from national-level deployment, and validating the building block 3 generation levels as technically feasible and cost-effective." That is, in addition to evaluating the cost of new renewable generation, EPA used IPM to project the level of renewable energy growth, including both the capacity added *before 2022*, and then to "apportion" the amount of additional renewable energy added from 2022 to 2030 based on the "geographic patterns" of renewable energy development identified through IPM.[49]

22. Furthermore, EPA used the model to satisfy the statutory requirement to evaluate the "cost" and "energy effects" of the rule.[50] Similarly, EPA used the IPM to ensure that the BSER measures it adopted would provide for adequate resources to supply electric demand and to operate the grid reliably.[51]

---

[48] EPA's Mitigation Measures Technical Support Document, at 3-20.
[49] EPA's Mitigation Measures Technical Support Document, at 4-6, http://www.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents.
[50] See EPA's Regulatory Impact Analysis for the Clean Power Plan Final Rule (August 2015), http://www.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents.
[51] *See* EPA, "Technical Support Document: Resource Adequacy and Reliability Analysis" (August 2015), http://www.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents.

B. Harvey's Reasons for Denigrating the Model Are Unpersuasive.

23. Harvey gives several reasons why the 2016 model results should not be "over-interpreted." None of these are persuasive.

24. First, relying on Harvey, EPA claims that the IPM relies on "model plants," essentially suggesting that the modeling is not "real" in some sense. However, Harvey concedes that the IPM "model" plants do in fact represent actual plants; the only difference is that some of the model plants may also represent a combination of generating unit at a single actual plant grouped together.[52] In addition, EPA only combines multiple actual units together into a single "model" plant if they match on *all* of the following "classification categories:" location, size, technology, heat rate, fuel choices, unit configuration, SO_2 emission rates, environmental regulations, and others.[53] As such, even the suggestion that the model plants may represent combinations of units is not likely to have a significant impact on how the modeling results compare with the real plants they are intended to reflect.

25. Second, EPA is wrong to claim that "the Model is not designed to predict the impacts of control requirements on individual sources, but instead to gauge the overall, power-sector-wide impacts of control requirements…." EPA Resp. at 64. The model predicts "overall" power-sector impacts by aggregating the impacts

[52] Harvey at ¶19, n.4.
[53] Harvey at ¶19, n.4.

experienced on a plant-by-plant basis. If the specific plant predictions are in error, the overall projections will also be in error. The IPM model results clearly demonstrate that some units will be forced to retire by the rule as soon as 2016. Even if EPA argues that it is not predicting which *specific* units will retire in 2016, the fact is that EPA predicts that the rule will cause about 11 GW of coal generation *somewhere* to retire in 2016 – units that would not be retiring in the absence of the Rule.

26. Third, Harvey asserts that the model does not accurately simulate the decisions which "real-world actors" would take because the IPM operates with "perfect foresight". In fact, the model does not operate with perfect foresight. The model is programmed with a set of assumptions and, based on those assumptions, predicts how electric utilities will act in response to a given policy. "Real-world actors" (the electric utilities) do the same thing—because utilities are required to make capital-intensive investments in extremely long-lived assets, they rely on long-term modeling projections in their major decision-making. In fact, they use modeling similar to IPM (my company, EVA, performs this modeling for some utilities). The assumptions used in models to project future events, of course, are subject to debate. But EPA believes its assumptions are reasonable, it believes that is model provides reasonably accurate forecasts of utility behavior in response to its rules, and it therefore cannot just disassociate itself from model results that do not support its preferred policy outcome.

27. In the "real world", using these types of models, utilities are moving forward and beginning to make decisions to retire coal plants based upon the timing and magnitude of the emission reductions required by the CPP. For example, Ohio Power has just entered into a stipulation in a case before the Public Utility Commission of Ohio wherein it will commit to reduce the coal burn at its Conesville 5-6 units no later than December 31, 2017 (units which IPM projected would retire in 2016) and must retire 3 coal units no later than 2030, which coincides with the timing of the CPP.[54] Northern States Power Company has specifically revised its 2016-2030 Upper Midwest Resource Plan to incorporate the projected impacts of the CPP to "accelerate the transition from coal energy to renewables" by retiring its largest coal units, Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026 (totaling 1,361 MW), to be consistent with the emission reduction limits of the CPP.[55]

C. EPA Used the Its Predictions of 2016 Retirements in New Rulemaking.

28. As Harvey concedes, EPA has already used the IPM's prediction of the specific units that will retire in 2016 because of the CPP in crafting another rule—the

---

[54] Ohio Power Company, Joint Stipulation and Recommendation before the Public Utilities Commission of Ohio, Case No. 14-1693-EL-RDR, December 14, 2015.

[55] Xcel Energy (Northern States Power) 2016-2030 Upper Midwest Resource Plan Reply Comments, Minnesota Public Utilities Commission Docket No. E002/RP-15-21, October 2, 2015.

Cross-State Air Pollution Rule Update (CSAPR Update).[56] The rule is intended to eliminate the significant contribution of air pollution from upwind states to their downwind neighbors.[57] To address that problem, the rule establishes "NO_x emission budgets" reflecting maximum level of NO_x emissions for each state's power sector. To determine individual state budgets for 2017, EPA first had to project each state's NO_x emissions for that year. EPA did so using the IPM-modeled "policy case" for the CPP—the model's projection of what the grid will look like given the CPP.[58] Since the CPP policy case projects numerous units will close in 2016 as a result of that rule, the NO_x emissions budgets calculated in EPA's CSAPR Update analysis are more stringent than they would otherwise be. In other words, EPA proposed stringent emission limitations in the CSAPR

[56] Harvey at ¶29, n.5 & ¶38, n.6. Harvey insists in footnote six that, despite the use of the CPP modeling results in crafting the CSAPR Update rule, the CPP "modeling results for the early years are not meaningful with respect to any specific units." Harvey at ¶38, n.6. But Harvey's only attempt to explain why he continues to hold that belief in spite of the use of the modeling results in the proposed CSAPR Update rule is that EPA's proposal remains open for comment. *Id.* In making this argument, Harvey cites a document that EPA placed into the CSAPR Update docket two days before it filed its Response here. *Id.* (citing Memorandum to Docket, Inclusion of the CPP in the baseline for the proposed Cross-State .Air Pollution Rule Update for the 2008 Ozone NAAQS (December 1, 2015) (EPA-HQ-OAR-2015-0500)). This memorandum says EPA is taking comment on whether the CPP modeling results should be used in the final CSAPR Update, but that's not what EPA actually said in the regulatory preamble to that rule. The regulatory preamble says, "The EPA will use [the CPP modeling results] for its modeling analysis for the final rule." In any event, open for comment or not, EPA's use of its CPP modeling results to craft the proposed CSAPR Update rule confirms that EPA does not believe the 2016 results are, as Mr. Harvey would have it, essentially worthless.

[57] 80 Fed. Reg. 75706, 75707 (Dec. 3, 2015).

[58] *Id.* at 75739.

Update rule in reliance on the 2016 CPP-caused retirements it now disavows for litigation purposes.

29. An example helps illustrate this result. As I showed in my report, the IPM projects that two units in Wisconsin, South Oak Creek 7 and Columbia 1, will retire in 2016 as a result of the CPP.[59] In the CSAPR Update rule, because EPA uses the CPP policy case to project NO_x emission in 2017, those units, totaling 848 MW of coal generation, are assumed to have retired by then.[60] The NO_x emissions from those two units, therefore, are eliminated from the inventory of emissions that EPA assumes Wisconsin utilities will emit in 2017. This provides a lower starting point for EPA's CSAPR Update rule analysis in determining the amount of NO_x emissions Wisconsin utilities can cost-effectively eliminate and therefore what Wisconsin's NO_x budget should be. As a result, EPA set a lower NO_x budget for Wisconsin than would be the case had EPA not assumed the CPP would cause those units to retire in 2016.

[59] *See* EVA Report at 62.

[60] *See* Parsed File: 5.15 Ozone Transport Base Case, 2018 (EPA-HQ-OAR-2015-0500-0162) (cells W6130 & W16674, indicating that the South Oak Creek 7 and Columbia 1 coal generation units, respectively, will retire by 2018) (available at www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2015-0500-0162). Although EPA claims that the reason it did not provide parsed results of the CPP modeling for 2018 is because those results "would not be useful or meaningful at the unit level," *see* Harvey at ¶29, EPA did provide parsed results for that exact same modeling run in support of the CSAPR Update Rule. *Id.*

30. EPA stated that it used the CPP policy case (IPM v.5.15) as its starting point for establishing the CSAPR Update budgets because it considered that modeling to be highly accurate:

> The EPA used IPM v.5.15 for developing the proposed state NOX emissions budgets discussed in Chapter 4 of this RIA, and for analyzing the proposed rule's cost, benefits and impacts. The EPA relied on IPM v.5.15 for these analyses so that the baseline for this RIA would reflect all on-the-books policies, including the CPP, as well as the most current power sector modeling data. *Using IPM v.5.15 for these analyses provides EPA with the best information available to develop the proposed rule* and to provide the public with the most current information possible.[61]

31. The bottom line is that EPA has proposed to impose more stringent NO_x emission reduction requirement under the CSAPR Update rule—a rule that will take effect in 2017—by relying on the specific modeling results that EPA now seeks to disclaim as meaningless. If, as EPA claims, the early retirements identified in the CPP modeling results are inaccurate, then it is unclear why EPA has also relied on them to establish binding emission reduction obligations in another rule. EPA's disavowal of its own IPM modeling results for litigation purposes is disingenuous.

[61] CSAPR Update Rule Regulatory Impact Analysis at 5-5, available at http://www.epa.gov/airmarkets/proposed-cross-state-air-pollution-update-rule (emphasis added).

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

Seth Schwartz

Dated: December 22, 2015

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

State of West Virginia, et al., Petitioners, **v.** **United States Environmental Protection Agency, et al.,** Respondents.	Case No. 15-1363 (and consolidated cases)

DECLARATION OF JARED SNYDER, ASSISTANT COMMISSIONER NEW YORK STATE DEPARTMENT OF ENVIRONMENTAL CONSERVATION

I, Jared Snyder, hereby declare:

1. I am the Assistant Commissioner for Air Resources, Climate Change, and Energy at the New York State Department of Environmental Conservation ("Department"). I have served in this role since joining the Department in 2007. My responsibilities as Assistant Commissioner include oversight of the Department's regulations implementing the Clean Air Act ("Act"), including submission of State Implementation Plans ("SIPs") and state plans to the U.S. Environmental Protection Agency ("EPA"), and coordination and implementation of state programs and policies to reduce greenhouse gas emissions. Part of my duties currently include coordinating the Department's response to EPA's final

Clean Power Plan rule under Section 111(d) of the Act, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule*, 80 Fed. Reg. 64,662 (Oct. 23, 2015) ("Clean Power Plan"). This involves evaluation of state plan options under the Clean Power Plan, outreach with stakeholders regarding the State's implementation of the Clean Power Plan, and ultimately the submission of a state plan to EPA to comply with the Clean Power Plan.

2. I have personal knowledge and experience regarding the Clean Power Plan, the Regional Greenhouse Gas Initiative ("RGGI"), and New York State's SIP submissions to EPA under the Act. This includes following the development and finalization of the Clean Power Plan rule, providing information and comments to EPA regarding the Clean Power Plan, working with representatives of other states on the development and implementation of the RGGI program,[1] and serving as the Department's primary official responsible for oversight of SIP submissions to EPA. I also currently serve as a Director on the RGGI, Inc. Board of Directors, and will serve as the Vice Chair of the RGGI, Inc. Board of Directors in 2016.

3. The purposes of this declaration are to: (i) briefly summarize existing state programs to reduce greenhouse gas emissions from the electric power sector;

[1] In addition to New York, the other states currently participating in RGGI are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, Rhode Island, and Vermont (collectively the "RGGI States").

(ii) describe activities the Department and the State have taken to evaluate the Clean Power Plan; (iii) provide examples of prior instances in which the Department has implemented regulatory programs applicable to the energy sector, prepared and submitted state planning documents to EPA under the Act, and collaborated with other states and entities such as the New York Independent System Operator ("NYISO"); and (iv) explain the State's readiness and ability to comply with the administrative and procedural requirements of the Clean Power Plan.

I. Existing State Programs to Reduce Greenhouse Gas Emissions

4. The State is already experiencing the impacts of climate change, and has recognized the urgent need to reduce the greenhouse gas emissions that contribute to climate change. For example, heat waves, coastal flooding, and riparian flooding will continue to threaten the State's environmental, social, and economic systems. The State has already been subject to an increase in extreme precipitation, with the Northeast experiencing a greater increase in extreme precipitation than any other region in the nation. Sea-level rise along New York's Atlantic coast has exceeded 18 inches since 1850. In 2011, Hurricane Irene and Tropical Storm Lee ravaged New York. A year later, Hurricane Sandy killed at least 61 New Yorkers and caused more than $50 billion in damage. Researchers estimate that sea-level rise since 1900 alone resulted in the flooding of

approximately 80,000 additional residents from Sandy, and sea-level rise alone will increase the costs from storms like Sandy in the future.

5. As a result of these impacts and for other reasons, New York State is committed to reducing greenhouse gas emissions, including by limiting those emissions from the electric power sector. The electric power sector is the largest source of greenhouse gas emissions across the country, and one of the largest sources of those emissions in the State.[2]

6. New York State has long supported federal efforts to limit greenhouse gas emissions, including through EPA regulation of the electric power sector under the Act. For example, as far back as 2008, the Department submitted comments to EPA on the Advance Notice of Proposed Rulemaking, *Regulating Greenhouse Gas Emissions under the Clean Air Act*, 73 Fed. Reg. 44,354 (July 30, 2008). More recently, even before EPA proposed the Clean Power Plan, New York joined the RGGI States in submitting comments to EPA supporting the regulation of greenhouse gases from the electric power sector under Section 111(d) of the Act.

7. In the absence of federal limits on greenhouse gas emissions from power plants, the State has implemented various programs to reduce those

---

[2] See U.S. Greenhouse Gas Inventory Report: 1990-2013, available at: http://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html; New York State Greenhouse Gas Inventory and Forecast: Inventory 1990-2011 and Forecast 2012-2030, Final Report April 2014, Revised June 2015, available at: http://www.nyserda.ny.gov/-/media/Files/EDPPP/Energy-Prices/Energy-Statistics/greenhouse-gas-inventory.pdf.

emissions from the electric power sector. For example, in 2012 the Department adopted regulations limiting carbon dioxide ("CO_2") emissions from new and expanded power plants. See *CO_2 Performance Standards for Major Electric Generating Facilities*, N.Y. Comp. Code R. & Regs. (NYCRR), tit. 6, Part 251, ("Part 251"). In addition, the State participates in RGGI, which is a multi-state market-based program that has set a limit on CO_2 emissions from both new and existing power plants since 2009. The Department implemented RGGI in New York through adoption of and revisions to its *CO_2 Budget Trading Program*, 6 NYCRR Part 242, ("Part 242") regulations.

8. New York has implemented these and other programs to reduce greenhouse gas emissions from the electric power sector without significant negative impacts to the economy or electric system reliability. In fact, CO_2 emissions from power plants covered by RGGI in New York have decreased by approximately 45% since 2005, while the state economy has grown by 8%. And according to independent analyses, the RGGI program has provided close to $700 million in economic benefits to the State, saving electricity consumers more than $200 million, and saving the State more than $400 million dollars in avoided fuel costs.[3]

[3] See The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States, Review of the Use of RGGI Auction Proceeds from the First Three-Year Compliance Period, Nov. 15, 2011, available at:

9. I coordinate with officials from other New York State agencies and authorities, including the New York State Public Service Commission and Department of Public Service (collectively "PSC") and New York State Energy Research and Development Authority ("NYSERDA"), to implement New York State's policies to reduce greenhouse gas emissions. These policies are in furtherance of the State's overall goal of reducing greenhouse gas emissions by 80 percent from 1990 levels by 2050. In addition to Part 251 and RGGI, this includes existing programs to transition to a clean energy economy and reduce greenhouse gas emissions from the electric power sector, such as:

a. PSC's Reforming the Energy Vision ("REV") initiative, which aims to achieve wholesale changes in the regulatory and market structures of the State's energy system, including to promote cleaner and more distributed sources of energy, increase resiliency and reliability, and empower consumers with additional choice.

b. The State Energy Plan, which establishes the State's clean energy goals for 2030, including: (i) achieving a 40% reduction in greenhouse gas emissions from 1990 levels from the energy sector; (ii)

---

http://www.dec.ny.gov/docs/administration_pdf/ag11rggi.pdf; The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States, Review of RGGI's Second Three-Year Compliance Period (2012-2014), July 14, 2015, available at: http://www.dec.ny.gov/docs/administration_pdf/ag15rggi.pdf.

generating 50% of electricity from renewable energy sources; and (iii) decreasing energy consumption in buildings by 23% from 2012 levels.

10. I am currently collaborating with PSC and NYSERDA regarding the implementation of REV, the State Energy Plan, and the Clean Power Plan. This collaboration will provide the State with the ability to implement the Clean Power Plan in conjunction with its other programs and policies regarding the electric power sector.

II. Evaluation of Clean Power Plan and Options for States

A. Development of Clean Power Plan

11. I have followed the development of the Clean Power Plan since at least 2013. For example, prior to EPA's proposal of the Clean Power Plan, I worked with representatives of the RGGI States to develop and submit comments supporting EPA's regulation of greenhouse gases from the power sector under Section 111(d) of the Act. These pre-proposal comments also included recommendations to EPA about such a regulation, such as providing flexibility to states to determine the appropriate compliance mechanism, allowing for the use of mass-based compliance approaches, and encouraging the use of multi-state programs.

12. I reviewed EPA's proposed Clean Power Plan, 79 Fed. Reg. 34,830 (June 18, 2014) ("Proposal"). The Proposal included many of the

recommendations the RGGI States made in the pre-proposal comments, including providing flexibility to states to build their own plans, allowing for mass-based programs, and facilitation of regional programs that include multiple states working together.

13. I worked with officials from the RGGI States to evaluate the Proposal, and to develop and submit comments to EPA on the Proposal. In their comment letters, the RGGI States supported the basic structure of the Clean Power Plan and provided recommendations to EPA to strengthen the final rule. See RGGI States' Comments on Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (Nov. 5, 2014), Document ID EPA-HQ-OAR-2013-0602-22395; RGGI States' Supplemental Comments on Proposed Clean Power Plan (Dec. 1, 2014), Document ID EPA-HQ-OAR-2013-0602-24208.

14. In addition to working together with the RGGI States, I worked with other New York State officials to evaluate the Proposal and its potential impacts on the State. Together with PSC and NYSERDA, the Department submitted comments to EPA on the Proposal. See New York State Comments on Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources (Dec. 1, 2014), Document ID EPA-HQ-OAR-2013-0602-23627. In addition to generally supporting the Proposal, New York State's comments included recommendations

to EPA regarding the methodology used by EPA to calculate the State's CO_2 emission goal.

B. Final Clean Power Plan Rule

15. The State has completed a review of the final Clean Power Plan and associated rulemaking documents. This includes my own review and assessment of the rule, evaluation of the final rule by other Department staff, collaboration with PSC and NYSERDA regarding the final rule, and discussions with NYISO, entities that would be subject to the state plan, and other stakeholders.

16. As a result of the State's prior efforts to evaluate and comment on regulation of greenhouse gases under Section 111(d) and the Proposal, as well as other activities, the State had an understanding of the basic structure of the Clean Power Plan even before EPA finalized the rule. This includes that EPA would set state-specific CO_2 emission goals that each state must meet, based on CO_2 emission performance rates reflecting the "best system of emission reduction" for existing fossil-fueled power plants as determined by EPA. Moreover, the final rule specifies guidelines for states to use in developing, submitting, and implementing state plans to achieve the rule's CO_2 emission goals. The final Clean Power Plan provides states with flexibility in developing their plans, including utilizing allowance trading programs like RGGI, working with other states, and other

measures. EPA did not significantly change this basic structure of the Clean Power Plan between the Proposal and the final rule.

17. EPA did, however, constructively address many of the issues raised by the RGGI States in their comments and by New York State in its own comments. The final Clean Power Plan, for example, includes state-specific CO_2 emission goals that better reflect progress already made by states like New York in reducing emissions, as well as additional emission reduction opportunities achievable in other states. Moreover, consistent with comments made by the RGGI States and New York, the final Clean Power Plan includes mass-based compliance options for states, facilitates the use of emissions trading for compliance, and clarifies certain issues regarding interstate collaboration.

C. Other Options Available to States

18. The Clean Power Plan provides states with the option of not submitting a state plan. In that case, EPA would not impose any sanctions on the state, such as the withholding of federal funds from the state. 40 C.F.R. § 60.5736. Instead, EPA would impose a federal plan, which is currently available for public comment. <u>See</u> *Federal Plan Requirements for Greenhouse Gas Emissions from Electric Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations; Proposed Rule*, 80 Fed. Reg. 64,966 (Oct. 23, 2015) (“Proposed Federal Plan”).

19. The Proposed Federal Plan also includes model rule language. This model rule language can be adopted by states for their own state plans under the Clean Power Plan. The model rule language may also be tailored by states in development of their state plans. This is similar to the processes described below, in which the RGGI States each adopted individual state regulations within approximately 24 months of the issuance of a final RGGI Model Rule in 2007, and adopted revisions to individual state regulations within approximately eleven months of the issuance of a revised RGGI Model Rule in 2013.

20. Because of the availability of the Proposed Federal Plan and associated model rule language, states do not need to devote significant time or resources to developing a state plan under the Clean Power Plan. Instead, states have the option of being subject to a federal plan, or of using model rule language contained in the Proposed Federal Plan.

21. Even for states that become subject to a federal plan, the Clean Power Plan still provides flexibility for states. For example, even after a federal plan has been implemented in a state, the federal plan will be withdrawn if and when EPA approves a plan submitted by the state. See 40 C.F.R. § 60.5720(b).

III. Examples of Prior Power Sector Regulations and Planning Efforts

22. The Department has extensive experience developing and implementing regulations applicable to the energy sector. This includes, for

example, the promulgation of Part 242 and Part 251 regulating CO_2 emissions from power plants, as well as regulations for other non-greenhouse gas pollutants. Before implementing these types of regulations applicable to the energy sector, the Department collaborates with entities such as NYISO, PSC, and NYSERDA, discussing, among other things, any issues regarding potential impacts to reliability or electricity cost. This experience will provide a useful framework for collaboration regarding electricity planning and utility regulation as the State develops and implements a plan to comply with the Clean Power Plan.

A. RGGI Implementation and Program Review

23. RGGI is one example of a program the State has developed and implemented to reduce greenhouse gas emissions from the power sector. RGGI is a market-based program to reduce CO_2 emissions from power plants, and is a cooperative effort amongst the RGGI States.

24. RGGI was initially developed through a collaborative process amongst the RGGI States. This included dialogue amongst the states, coordination amongst the environmental and energy agencies within each state, discussions with NYISO and the other relevant regional organizations, modeling of the electricity sector under various scenarios, and interaction with stakeholders and experts to obtain input regarding the design of the RGGI program.

25. The RGGI program is grounded in each state's own statutory and regulatory authorities. Following the initial development process, the RGGI States collectively drafted a Model Rule containing model regulatory language that could be used to implement the RGGI program in each state. The RGGI States issued a final Model Rule with technical corrections on January 5, 2007. See Regional Greenhouse Gas Initiative Model Rule, Final with Corrections, available at: http://www.rggi.org/docs/model_rule_corrected_1_5_07.pdf.

26. Each of the RGGI States then used this Model Rule as the basis for developing its own regulation and implementing RGGI through its own statutory and/or regulatory processes. As a result, each state established a "CO_2 Budget Trading Program" regulation that contained substantially similar provisions.[4] These regulations became effective in each state by the end of 2008, or within approximately 24 months of the release of the final corrected Model Rule. During the interim period between the release of the Model Rule and the adoption of individual state regulations, as part of individual state rulemakings, New York and other states participating in RGGI worked together with relevant independent

[4] See Conn. Agencies Regs. § 22a-174-31; Del. Admin. Code tit. 7, ch. 1147; 06-096 Me. Code R. 156; Md. Code Regs. 26.09; 310 Mass. Code Regs. 7.70; N.H. Code Admin. R. Env-A 4600, 4700; N.Y. Comp. Codes R. & Regs. tit.6, § 242; R.I. Code R. 25-4-46:46; Vt. Code R. 12-031-002.

system operators and public utility commissions to assess electricity cost and reliability issues.

27. The primary requirement of the RGGI program, as implemented by each state's CO_2 Budget Trading Program, is for each power plant subject to the program to obtain a tradeable CO_2 allowance for each ton of CO_2 it emits over a compliance period. RGGI's first three-year compliance period began on January 1, 2009, within just a few months of when each of the RGGI States established its individual CO_2 Budget Trading Program. At the end of the compliance period, each power plant must make such CO_2 allowances available to the Department, or to the environmental agency in the relevant RGGI state, for permanent deduction.

28. Collectively, the RGGI States' CO_2 Budget Trading Programs establish a declining cap on CO_2 emissions from the power sector within the RGGI States. Since 2005, CO_2 emissions from power plants covered by RGGI have decreased by approximately 45% across the RGGI States.

29. After the initial three-year compliance period (2009-11) of effective program operation, the RGGI States conducted a comprehensive Program Review in 2012. This Program Review assessed the benefits and impacts of the program to date, and evaluated potential options for changes to the RGGI program. The 2012 Program Review included many of the same components as the initial development of the RGGI program, including coordination amongst the environmental and

energy agencies of each state, outreach to stakeholders, and electricity sector modeling.

30. Following this 2012 RGGI Program Review, the RGGI States established a new regional CO_2 emissions cap of 91 million short tons, a 45 percent reduction from the original regional cap. Moreover, under the program changes following the 2012 Program Review, the cap will decline by 2.5 percent each year from 2015 through 2020.

31. To implement these and other changes to the RGGI program, the RGGI States first collectively developed revisions to the RGGI Model Rule. The RGGI States issued a revised Model Rule on February 7, 2013. See RGGI Model Rule, Issued February 7, 2013, Revised December 23, 2013, available at: http://www.rggi.org/docs/ProgramReview/_FinalProgramReviewMaterials/Model_Rule_FINAL.pdf. Each state then revised its own CO_2 Budget Trading Program through state-specific statutory and/or regulatory processes. In New York State, the Department proposed amendments to its Part 242 regulation on July 10, 2013, and adopted such amendments effective on January 1, 2014. The RGGI States all successfully adopted regulatory changes in time for the new lower regional cap to be in place for 2014, or within approximately eleven months of the release of the revised RGGI Model Rule.

32. Therefore, on two separate occasions, the State has successfully worked with other states to develop and implement a cooperative regulatory program for reducing greenhouse gas emissions from power plants. On both occasions, this included many of the same elements that may be required for states to develop and implement state plans under the Clean Power Plan, such as electricity sector modeling, collaboration with environmental and energy agencies, outreach to stakeholders, interaction with Independent System Operators/Regional Transmission Organizations, and individual state legislative and/or regulatory processes. Moreover, many of the steps taken by the RGGI States to design the RGGI program may not be necessary for states developing a state plan under the Clean Power Plan, because of the availability of existing regulatory language and other materials for states under the Clean Power Plan.

33. New York State's experience in developing, implementing, and revising the RGGI program provides a useful framework for potential collaboration by other states in submitting a plan for compliance under the Clean Power Plan. It also demonstrates the ability of states to develop common regulatory language, and then independently implement such language expeditiously though each state's own statutory and regulatory processes.

B. SIP Submittal and Federal Regulatory Review

34. The Department has decades of extensive experience developing plans for submittal to EPA under the Act. Most notably, this includes the development and submittal of SIPs to meet and maintain relevant National Ambient Air Quality Standards ("NAAQS") for criteria pollutants under the Act. The process for developing SIPs and submitting SIPs to EPA for approval shares many similarities with the process for developing and submitting a state plan to EPA for approval under the Clean Power Plan. At the same time, certain elements of many SIP processes will not be part of the state plan development process under the Clean Power Plan, such as complex ambient air quality modeling analyses.

35. Part of the SIP process includes working with EPA to understand federal regulatory requirements. For example, Department staff frequently discuss applicable requirements with EPA staff, and then incorporate any feedback from these discussions into SIP submittals. This is similar to the ongoing process with EPA staff regarding the Clean Power Plan, in that Department staff are engaged in an ongoing dialogue with EPA staff regarding specific provisions of the Clean Power Plan, which in turn informs evaluation of state plan options under the Clean Power Plan.

36. The SIP process typically includes the promulgation of regulations by the Department as well as emissions inventory projections and complex ambient

air quality modeling analyses. As part of SIPs, the Department commonly promulgates new regulations, or revises existing regulations, applicable to the electric power sector. Moreover, the establishment of such regulations is often subject to a timeline established by EPA, which is sometimes shorter than that provided for state plan submittal under the Clean Power Plan.

37. Department staff routinely evaluate changes to federal standards under the Act, including standards applicable to the electric sector. This evaluation includes an assessment of the impact of any federal regulation on the State's electric power system, and frequently involves coordination with PSC, NYSERDA, and NYISO.

38. In addition to regulatory changes to meet or maintain a NAAQS and submit a SIP, the Department routinely promulgates regulations to implement other federal standards under the Act. The process of responding to new EPA regulations, including by making changes to Department regulations, is therefore familiar to me and to Department staff.

39. The Department's familiarity with SIP preparation and review of federal regulations will serve to facilitate its response to the Clean Power Plan. The processes the Department undertakes to prepare SIPs and respond to other relevant EPA regulations are similar to what the Department is currently undertaking in response to the Clean Power Plan.

C. Other Planning Efforts and Regional Collaboration

40. The State has conducted numerous analyses of the electric power sector in support of various policies and regulations. In addition to modeling and other analyses to support RGGI and SIPs, this also includes analyses in support of other air regulations, clean energy policies such as the REV initiative and State Energy Plan, and other programs. These efforts have been ongoing for years and will help inform evaluation of options for the State under the Clean Power Plan.

41. The Department has also worked effectively with its counterpart agencies in other states to develop coordinated regulatory programs implicating the laws of multiple states. In addition to RGGI, this also includes participation in the Ozone Transport Commission and development of SIPs in collaboration with other states. For example, the Department regularly coordinates SIP submissions for ozone and fine particulate matter (PM 2.5) non-attainment with the neighboring states of Connecticut and New Jersey. This coordination includes inventorying of emissions and projections, air quality modeling, and emission reduction strategies reflected in individual state rulemakings.

IV. New York's Ability to Develop a State Plan

A. Coordination with Other Policies

42. While the Clean Power Plan requires states to submit plans to EPA for compliance, actual regulatory requirements under a state plan will be applicable

to owners or operators of affected electric generating units, and not states, environmental or energy agencies, or other organizations. In this respect, the Clean Power Plan is similar to other air emission regulations applicable to the electric power sector.

43. Moreover, because of this similarity to other air emission regulations and for other reasons, I do not expect the Clean Power Plan to interfere with the State's other energy and environmental policies, including other programs to reduce greenhouse gas emissions from power plants. The Department's ongoing coordination with PSC, NYSERDA, and NYISO regarding the implementation of policies applicable to the electric power sector will enable the State to allocate staff resources efficiently.

44. Furthermore, many of the State's other policies, such as the REV initiative and the State Energy Plan, are intended to help serve some of the same objectives as the Clean Power Plan. For example, many of these other policies are aimed, in part, at reducing greenhouse gas emissions, accelerating the transition to cleaner and renewable energy sources, and reducing other air pollutants. In this way, the Clean Power Plan is complementary to the State's existing efforts under State law.

B. State Plan Timing and Submittal

45. The Clean Power Plan requires that, by September 6, 2016, states submit to EPA either a final state plan or an initial submittal requesting an extension. 40 C.F.R. § 60.5760. In order to be granted by EPA, an initial submittal requesting an extension must contain only minor and non-binding information, including: (1) an identification of the final plan approaches under consideration and a description of progress made to date; (2) an explanation of why additional time is necessary to submit a final state plan; and (3) a description of the opportunities for public comment and meaningful engagement with stakeholders during preparation of the initial submittal, and plans for engagement during development of the final plan. See id.; id. § 60.5765; EPA Memorandum from Stephen D. Page to Regional Air Directors, Initial Clean Power Plan Submittals under Section 111(d) of the Clean Air Act, October 22, 2015, available at: http://www3.epa.gov/airquality/cpptoolbox/cpp-initial-subm-memo.pdf. For those states granted an extension, a final state plan must be submitted to EPA by September 6, 2018. 40 C.F.R. §§ 60.5760, 60.5765. Therefore, states have almost three years from the finalization of the Clean Power Plan to the extended deadline for final state plan submittal. For the reasons described in this declaration, the Department can readily meet the initial and final submittal deadlines.

46. In addition to the availability of this almost three-year period for final state plan submittal to EPA, the final CO_2 emission goals in the Clean Power Plan do not need to be achieved until 2030. See 40 C.F.R. §§ 60.5770, 60.5855. Furthermore, the final rule establishes less stringent state-specific interim CO_2 emission goals, which must be achieved on average or in aggregate over the eight-year interim period from 2022-2029. See id. States therefore have flexibility in determining the pace of emission reductions over the interim period. In other words, actual requirements on affected power plants will not become effective until 2022 under the Clean Power Plan, and even then will only be based on a phased-in interim goal that is less stringent than the final goal for 2030.

C. Development of State Plan

47. The State has already begun its efforts to develop a state plan for compliance with the Clean Power Plan. In addition to evaluation of the various plan approaches available to states under the Clean Power Plan, these efforts include stakeholder outreach, ongoing modeling and other analyses of the electric power system, collaboration with NYISO, PSC, and NYSERDA, and discussions with officials representing the RGGI States.

48. The State is conducting two parallel stakeholder outreach processes. These include:

a. New York State-specific outreach, including discussions with entities that would be subject to the state plan to comply with the Clean Power Plan, NYISO, non-governmental organizations, and environmental justice communities. The Department has already held initial focus group meetings with two of these groups to discuss development of the state plan and implementation of the Clean Power Plan, including on November 2, 2015 with representatives of entities that would be subject to the state plan, and on November 20, 2015 with non-governmental organizations. The Department plans to hold a webinar with representatives of environmental justice organizations on December 11, 2015, which will also include discussion of plans for additional engagement with communities across the State.

b. Stakeholder outreach together with the RGGI States. The outreach by the RGGI States began with a meeting in New York City on November 17, 2015, and included discussion of electricity sector modeling, key topics regarding RGGI program review, and potential compliance under the Clean Power Plan. This includes the potential for compliance together with other states, such as through the addition of new RGGI participating states, naming additional trading partners, or the so-called "trading ready" mechanism under the Clean Power Plan. The RGGI States also released materials explaining plan options available under the Clean Power Plan, describing key items for RGGI program review, listing draft assumptions for electricity sector modeling, and providing an anticipated schedule of additional stakeholder outreach. See November 17 Meeting Materials, available at: http://www.rggi.org/design/2016-program-review/rggi-meetings.

49. The RGGI States are currently conducting electricity sector modeling and other analyses to support review of the existing RGGI program and potential compliance options under the Clean Power Plan. This includes the use of modeling to project emissions, CO_2 allowance prices, electricity prices, and other variables under various Clean Power Plan compliance scenarios.

50. In addition to this electricity sector modeling being conducted by the RGGI States, New York is conducting its own modeling and other analyses to support electricity sector planning, which will inform consideration of state plan options under the Clean Power Plan. This includes the State Resource Planning effort, which is a collaborative study that includes participation by staff from the Department, NYSERDA, and PSC, in addition to participation of NYISO and regulated utilities. This effort is intended, in part, to assess the State's electricity system to ensure that it meets various public policies and regulations by 2030, including the Clean Power Plan, while maintaining reliability with the least

economic impact to consumers. This effort is complementary to the State Energy Plan and other ongoing state programs, and will be able to accommodate considerations regarding the State's implementation of the Clean Power Plan.

51. The Department collaborates with NYISO on an ongoing basis regarding the implementation of certain of its environmental regulatory programs. For example, Department staff periodically attend meetings (either in-person or via teleconference) of NYISO's Electric System Planning, Market Systems, and Installed Capacity Working Groups. Department staff also meet with the New York State Reliability Council every two months, which includes participation by NYISO. This also includes collaboration with NYISO regarding the development and implementation of RGGI and regarding the Clean Power Plan. The Department has already begun discussions with NYISO regarding state plan options under the Clean Power Plan, including on November 19 and 20, 2015 at NYISO's Environmental Advisory Council's Fall Meeting. Based on my discussions with NYISO representatives, my understanding is that NYISO has reviewed the final Clean Power Plan and has preliminarily concluded that EPA addressed many of the key concerns NYISO raised in its public comments on the Proposal.[5]

---

[5] See, e.g., NYISO, EPA Clean Power Plan, Preliminary Assessment of Impact on New York, October 27, 2015, available at: http://www.nyiso.com/public/media_room/publications_presentations/index.jsp.

D. Department's Ability to Meet Clean Power Plan Deadlines

52. The Department has sufficient staff, time, and resources to evaluate options for the State under the Clean Power Plan, conduct relevant coordination and stakeholder outreach activities, perform appropriate analyses, and ultimately prepare its initial submittal. Based on the three required components of an initial submittal, as described above, the Department will, at a minimum, be in a position to obtain the two-year extension for submittal of a final state plan.

53. The Department has the ability to conduct the activities necessary to develop and implement a final state plan under the Clean Power Plan. This is partly because of prior experiences by the Department in implementing similar programs applicable to the electric power sector, such as the preparation of SIPs.

54. Based on my personal knowledge and experience, and the State's prior experience, I am confident that the State will be able to meet the deadlines established for state submittals under the Clean Power Plan. At a minimum, this includes the filing of an initial submittal by September 6, 2016, and a final state plan by September 6, 2018.

E. Impacts of Potential Stay

55. The ability of the State to effectively coordinate the Clean Power Plan with other energy sector policies and planning efforts could be negatively impacted by any stay of the Clean Power Plan. This is partly because a stay may not

ultimately result in postponement of the submittal or compliance deadlines under the Clean Power Plan, and the State is currently working towards meeting those deadlines.

56. Any stay may also delay actions that other states or affected power plants would otherwise have taken to prepare for compliance with the Clean Power Plan. This could interfere with states' energy planning efforts that may be accounting for the Clean Power Plan, delay actions that would otherwise reduce greenhouse gas emissions, or make it more costly for states and affected power plants to comply with the rule.

57. Any stay of the Clean Power Plan would also impair opportunities for multi-state collaboration. This is because states would not be able to fully assess their options for state plan approaches under the Clean Power Plan. For example, part of a state's consideration of plan approaches may depend on the compliance paths being pursued by other states, such as whether a state intends to be "trading ready" under the Clean Power Plan. If states do not provide an initial indication of the plan approach or approaches under consideration, then states may not be able to accurately conduct electricity sector modeling or other analyses of Clean Power Plan implementation.

58. Any delay in reducing greenhouse gas emissions, such as a delay that might result from a stay of the Clean Power Plan rule, will have negative impacts

on the State. This is because of the urgent need to reduce greenhouse gas emissions from the nation's power sector. The State has long supported federal efforts to limit greenhouse gas emissions, as such action is essential to limiting the impacts of climate change.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct. Executed on December 4, 2015.

Jared Snyder
Assistant Commissioner for Air Resources, Climate Change, and Energy
New York State Department of Environmental Conservation

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

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et. al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY Respondents.	Case Nos. ________

DECLARATION OF STUART SPENCER, ASSOCIATE DIRECTOR, OFFICE OF AIR QUALITY, ARKANSAS DEPARTMENT OF ENVIRONMENTAL QUALITY

I, Stuart Spencer, declare as follows:

1. I am the Associate Director of the Office of Air Quality at the Arkansas Department of Environmental Quality ("ADEQ"). I have been employed at the ADEQ for approximately five years. As part of my duties, I supervise a staff of approximately eighty employees. The ADEQ Office of Air Quality has received all delegable air programs, including the Title V program for major sources of pollutants, from Region 6 of the United States Environmental Protection Agency

(EPA). These programs include the New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), Prevention of Significant Deterioration (PSD) and the State Implementation Plan (SIP). By working closely with businesses and industries, the ADEQ Office of Air Quality issues permits that help maintain and improve the air quality for all citizens in the State. The Office of Air Quality has four branches; Program Support, Planning and Air Quality Analysis, Permits, and Compliance Monitoring. I have personal knowledge and experience to understand the steps that the State of Arkansas has taken and will need to undertake in response to the EPA's Section 111(d) Rule.

2. Based on my experience, I have determined that implementing the Section 111(d) Rule will be a complicated and time-consuming endeavor. The Section 111(d) Rule is unlike any other Clean Air Act implementation undertaken by the State of Arkansas. Specifically, the Section 111(d) Rule's reliance on measures that require the reduction of demand for a particular source of energy - building blocks 2 and - are entirely unprecedented. The State of Arkansas will be required to expend a large number of resources to design a State Plan that incorporates these building blocks.

3. Already, six employees have expended approximately 300 hours on understanding the Section 111(d) Rule and preparing for its implementation, including, but not limited to:

a. Reading the rule and associated technical documentation;

b. Attending briefing sessions with State officials;

c. Participating in group calls and webinars on the final rule;

d. Participating in states' groups discussions on the final rule;

e. Preparing presentations on the final rule for various state and local groups;

f. Outreach and communications with affected facilities and stakeholders;

g. Preparation for press events and initial stakeholder meeting post-final rule; and

h. Preparing for and hosting a 111(d) stakeholder meeting on October 9, 2015 at ADEQ headquarters.

4. Absent a stay from this Court, it is not practical for the State of Arkansas to wait to continue work on its State Plan. It is already doubtful that the ADEQ can design a State Plan in time to comply with the EPA's deadlines. Waiting until the litigation concludes will make compliance with the EPA's deadlines impossible. And any delay in designing a State Plan will risk the State of Arkansas's ability to comply with the EPA's deadlines. ADEQ foresees that the preparation of a State Plan will entail a lengthy process. The usual timeline to

develop a SIP averages 18 months, which would include (in regards to preparing a state "Clean Power Plan"):

a. research and development of a State Plan and accompanying regulation language, including requisite analyses under Arkansas Act 382 of 2015, which mandates that any State Plan must be approved by the Arkansas General Assembly prior to submission to the EPA. Additionally, Act 382 requires that any State Plan must be supported under state law by a number of analyses, including economic, rate payer and reliability impact assessments;
b. internal review of draft language;
c. submission of any proposal to the Governor and legislature;
d. rulemaking initiation with the Arkansas Pollution Control and Ecology Commission (hereinafter "APC&EC");
e. submission of rulemaking packet to Legislative Committees for approval;
f. adoption of rulemaking with the APC&EC;
g. final development of draft § 111(d) State Plan;
h. public notice and public comment period;
i. response to comment (time can vary according to the number and comments received); and

j. submittal of the State Plan to EPA.

(See also attached Rule 111(d) Plan Development and Submission Timeline)

Plans including controversial issues or multistate efforts can reasonably be expected to take longer. Considering all these steps necessary to develop a State Plan, the State of Arkansas will require significant resources and time, which are not available at the state level, to develop and implement an approvable plan.

i. In addition, it is uncertain whether any State Plan will be approved by the EPA and implemented in time for utilities to comply with the Section 111(d) Rule's interim goals, making any delay in expending resources impractical. Waiting until litigation is complete to begin work on a State Plan would make it impossible for the State of Arkansas to meet the Section 111(d) Rule's interim and final compliance goals, and any delay in designing a State Plan will risk the State of Arkansas's ability to comply with the EPA's deadlines.

ii. Absent a stay from this Court, planning and compliance for the Section 111(d) Rule, including designing a State Plan, will require an unprecedented amount of ADEQ resources, the expenditure of which will begin immediately. The Section 111(d) Rule gives the State of Arkansas until September 6, 2016, to submit certain elements of its State Plan. If EPA approves, the State will have until September 6, 2018, to submit a final State Plan. Preparation of a a timely plan will require several dedicated ADEQ staff members, as well as significant resources from other state agencies, stakeholders, and the legislature.

The ADEQ and the Arkansas Public Service Commission (APSC) initiated the post-final Clean Power Plan rule stakeholder process via a meeting held at the ADEQ headquarters on October 9, 2015. The October 9th meeting was attended by approximately two dozen primary stakeholders, as well as a room full of interested individuals, entities and organizations. Several ADEQ staff members attended the meeting and undertook more than 85 cumulative hours of preparation and presentation time. The objective of the stakeholder gathering was to gauge the primary issues of concern and interest and to set the framework for further meetings. At this point in time, all options are on the table and under consideration, as long as they achieve the directive ADEQ has received from Arkansas's Governor to seek the lowest cost option for compliance.

The ADEQ is currently mapping out its strategy for future stakeholder engagement. At a minimum, it is estimated that we will hold at least ten meetings, including educational listening sessions, over the next year. It is estimated that staff will expend at least 600 cumulative hours in preparation for attendance at those meetings.

iii. Absent a stay from this Court, if the State of Arkansas chooses to adopt a multi-state approach to complying with the Section 111(d) Rule, the State of Arkansas may need to enter into either a memorandum of understanding or agreement with the other states. The State of Arkansas has limited experience in pursuing this type of agreement with other states, and anticipates that a significant amount of time would be required to negotiate and reach consensus on the content of such an agreement with other state agencies.

iv. Undertaking these measures will seriously disrupt the State's sovereign priorities, which would otherwise be devoted to addressing other pressing issues of public concern. The ADEQ has already identified a number of concerns with the final rule that will require State resources to address. The fundamental areas of concerns are potential economic impacts and the timing associated with implementation of the rule (specifically, artificial time constraints imposed by the rule). The ADEQ also is concerned with ensuring that our electric generating units that are currently in operation are allowed to run the course of their "remaining useful lives." Premature closure of a plant will result in stranded assets, the costs of which will be borne by electric consumers. Moreover, we want to ensure that the State is given proper credit for projects currently underway that are already part of the utility integrated resource planning (IRP) process. Additionally, at this point, there is uncertainty as to what a federal plan will look like (it is proposed). Failure to act or plan could result in a federal plan which does not allow sufficient flexibility to meet load demand, protect natural resources, and assure lowest cost energy. It is difficult to weigh options (i.e., state plan or federal plan), if the parameters of the federal plan are as yet undefined. The final rule also raises concerns about certainty and predictability of energy supply and costs critical to new load demand and economic development.

I have prepared the above and foregoing statements and they are true and correct to the best of my knowledge and belief.

IN WITNESS WHEREOF, I hereunto set my hand this 16th day of October, 2015.

Stuart Spencer
Associate Director, Office of Air Quality
Arkansas Department of Environmental Quality

SUBSCRIBED AND SWORN TO before me, a Notary Public, this 16th day of October, 2015.

Sarah Martin
Notary Public

My Commission Expires:

9-7-2024

SARAH MARTIN
FAULKNER COUNTY
NOTARY PUBLIC - ARKANSAS
My Commission Expires September 07, 2024
Commission No. 12400461

"Clean Power Plan"/111(d) Plan Development and Submission Timeline

2015

August 3	Federal	EPA releases final "Clean Power Plan" rule and proposed Federal Plan
Mid-October	Federal	Projected publication of the final "Clean Power Plan" rule in the Federal Register
October	State	ADEQ/PSC convene stakeholder roundtable meeting/develop stakeholder meeting schedule
December/January 2016	State	Complete development of assumptions/scenarios in order to run models required by Arkansas Act 382 (process will involve stakeholders, state agencies [ADEQ, PSC, AEDC] and possibly contracted consultants)

2016

January -May	State	Conduct and complete Arkansas Act 382-required analyses of utility-costs-impact, environmental -impact, and economic-impact
May-June	State	Develop 111(d) "Initial Plan"
July	State	Brief Governor's Office/General Assembly with draft 111(d) "Initial Plan"
Sept. 6	Federal	Extension request/"Initial Plan" due to EPA.
September-September 2018	State	Rulemaking/State Plan development/stakeholder engagement/inter-agency engagement (subject to legislative and Governor's approval).

2017

September 6	Federal	State's "Progress Report" on "Initial Plan" due to EPA.

2018

September 6	Federal	State's Final Plan due to EPA.*

*September 6, 2018 deadline is subject to EPA approval of state's September 6, 2018 extension request and "Initial Plan".

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

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ______

DECLARATION OF PATRICK STEVENS,
WISCONSIN DEPARTMENT OF NATURAL RESOURCES

I, Patrick Stevens, declare as follows:

1. I am the Division Administrator of the Environmental Management Division at the Wisconsin Department of Natural Resources ("WDNR").

2. I have personal knowledge and experience to understand what steps the State of Wisconsin has taken and will need to undertake in response to the EPA's proposed *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units*, 79 Fed. Reg. 34, 830 (June 18, 2014) ("111(d) Rule").

3. Based on my experience in this position, I have determined that implementing the 111(d) Rule will be a complicated and time-consuming endeavor. In terms of scope and level of effort, the 111(d) Rule is unlike any other Clean Air Act implementation activity undertaken by the WDNR in recent

history. Already, WDNR employees have expended over 3200 hours understanding the proposed rule and evaluating potential implementation options, including outreach to numerous stakeholders[1] in Wisconsin, organizing individual and joint stakeholder meetings and listening sessions, participating in regional collaborative efforts with other states and industry participants such as Midcontinent States Environmental and Energy Regulators and the Midwest Power Sector Collaborative, attending EPA listening sessions and conference calls, and in-depth analysis of the impact of the 111(d) Rule on the state and regional systems.

4. WDNR also expended significant resources to understand how the proposed 111(d) Rule would impact energy providing utilities, including investor-owned utilities, municipal utilities, and co-operative utilities. WDNR, together with the Public Service Commission of Wisconsin ("PSCW") has studied each utility's unique fleet of electric generating units, interactions among the different utilities, interactions between in-state and out-of-state facilities of an individual utility, and the interaction of Canadian hydro-electric power with the state and regional system.

5. Much of the time and energy invested in understanding and evaluating the proposed rule is irrelevant to the final 111(d) Rule. The final 111(d) Rule is significantly different, which means WDNR staff has begun another intensive investigation into the requirements of the Rule and start over with evaluation of compliance paths. Similarly, if the Rule is not stayed and the Rule is altered or vacated, much of the time and energy invested in understanding and compliance planning for the final 111(d) Rule may have been wasted.

6. State government resources necessary for implementation of the 111(d) Rule are expected to be even greater than what has already been expended. The 111(d) Rule gives the state until September 6, 2016, to submit an initial state plan, with a two-year extension available. In the event Wisconsin decides to prepare a state plan, preparing and submitting a timely plan will require several dedicated WDNR staff members, as well as significant resources from other state agencies, stakeholders,

[1] Stakeholders include regulated utilities, merchant-owned EGUs, municipal utilities, utility cooperatives, environmental groups, industry groups, residential and small business representatives, MISO, M-RETS, and representatives from other entities interested in or impacted by the 111(d) Rule.

and the legislature. Though the time to submit a plan was extended in the final rule, the emissions reduction goals must still be met by 2030. Therefore, absent a stay, compliance planning and implementation must both begin immediately in order to meet the final goal. Any delay in submitting a final plan for approval will only reduce the amount of time Wisconsin has to implement that plan. If the rule is not stayed during litigation, and is ultimately vacated or amended, significant time and resources will be wasted on compliance planning and implementing the current 111(d) Rule.

7. Both the proposed and the final 111(d) Rule include measures that are not within the direct control of either utilities or the WDNR, and will require large scale changes to environmental regulation in Wisconsin. The final rule sets a rate for existing plants that is not achievable absent measures taken outside of the plant's boundaries. WDNR's current authority is limited to regulation of stationary sources, as well as some mobile sources, of emissions. In order to have the ability for WDNR to directly regulate and enforce in-state compliance options of the plan that are outside of the fence-line of the stationary sources, such as energy efficiency and increased reliance on renewable energy, the Wisconsin Legislature will have to re-write state statute to fundamentally change the WDNR's authority. Furthermore, it is unknown how the Legislature would react to any such proposal. These complications highlight the difficulty of creating an enforceable compliance path either as an individual state or as a region since many of the carbon-reduction measures are not within the direct control of the regulated utilities. Legislative changes would be most appropriate after the rule is fully adjudicated.

8. More specifically, the process to create a state plan for the 111(d) Rule includes several required steps and will take three or more years to complete. The 111(d) Rule describes at least six potential compliance plan options available to the states. EPA identifies seven specific elements that every state plan must include, not including additional demonstrations that a state has considered electric system reliability in developing its plans and that the state engaged all stakeholders potentially impacted by the plan. In addition, EPA specifies certain additional components that certain plans must include, including a demonstration that the plan's reductions are quantifiable, non-duplicative, permanent, verifiable, and enforceable. Some compliance options could require additional legislative changes. The

111(d) Rule should be stayed during litigation because a policy change this significant should not be pursued until the legality of the 111(d) Rule is definitively determined.

9. Demonstrating that Wisconsin's 111(d) state plan meets all necessary components will require Wisconsin to develop and finalize new state rules and potentially acquire statutory changes by September 6, 2018, assuming Wisconsin receives a two-year extension. WDNR estimates that a simple, noncontroversial state rule takes at least 27½ months to complete all steps required under Wis. Stat. ch. 227, Subchapter II. In my experience, the complex and contentious 111(d) Rule will take significantly longer than the timeframe for a simple, non-controversial rule because of the stakeholder input required for such a comprehensive regulation of the entire electric generating system. In addition, the federal requirements for adoption and submittal of state plans at 40 C.F.R. 60.23 also include requirements for public hearing and opportunity for comment. In my opinion, it will be difficult and will require dedicated resources for Wisconsin to complete a state plan within the timeframes allowed in the 111(d) Rule. Absent a stay of the Rule, these state law changes may ultimately need to be reversed or otherwise changed again once litigation is complete.

10. In the absence of a stay, it is not practical for WDNR to wait for the completion of litigation to begin working with utilities on compliance. It is already doubtful that the state plan will be approved and implemented in time for utilities to comply before the first interim goal compliance period in 2022. Waiting until litigation is complete to begin that work would make it impossible for Wisconsin to meet interim goals, and even more costly and difficult to meet the final 2030 goal. In the event the state chooses to participate in certain compliance options involving a multi-state plan, the state may need to enter into either a memorandum of understanding or agreement with the other states. For example, under certain multi-state planning scenarios, EPA requires states to agree upon a joint emissions reduction goal equivalent to the individual goals of each participating state and to document the analytic process, tools, methods, and assumptions used to calculate the joint multi-state goal. The state has limited experience in pursuing this type of agreement with other states, and anticipates that a significant amount of time would be required to negotiate and reach consensus on the content of such an agreement with other state

agencies. This time-consuming process would be a waste of resources if the 111(d) Rule is ultimately changed or vacated. Even a minor adjustment in goals for participating states, compliance options available, or compliance time could dramatically change the compliance plan. Given the lengthy planning process for writing, submitting, and approval of a plan, and associated state law changes, it is likely it would not be practical to re-submit a new compliance plan within the 111(d) timeframes if litigation alters the final 111(d) Rule but does not stay compliance during litigation. Utilities affected by the state's originally submitted compliance plan will likely have already made adjustments to their operation, rendering a successful legal challenge useless.

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

Executed on 10/16/15

Patrick Stevens

366A

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

State of West Virginia, *et al.* Petitioners, v. United States Environmental Protection Agency, Regina McCarthy, Administrator, United States Environmental Protection Agency, Respondents.	)	No. 15-1363 (and consolidated cases)

DECLARATION OF MICHAEL I. STORCH

I, Michael I. Storch, declare as follows:

1. I submit this declaration in support of this Response in Opposition to Petitioners' Motions for Stay by Respondents-Intervenors.

2. I am Michael I. Storch. Executive Vice President , Chief Company Development Officer, Enel Green Power North America, Inc. I am responsible for commercial activities including all mergers and acquisition related activities in the "Americas" with a heavy focus on creative structurs, tax optimization,

negotiations and other commercial activities related to renewable energy projects. I have a Bachelor of Business Administration degree from Baruch College, New York and am a certified public accountant.

3. I have worked for twenty-eight years in the renewable energy space and have extensive expertise in all aspects of project finance, tax investor transactions, power purchase agreements and project development.

4 My declaration is based on my direct experience as a professional responsible for mergers and acquisitions, management of operations, project financing and structured tax financings, administration, investor relations and strategy and business development work.

5. I am supplying this declaration at the request of movant-intervenors the American Wind Energy Association ("AWEA") and Solar Energy Industries Association ("SEIA").

6. The purpose of my declaration is to provide information to the court relating to the question of whether the wind and solar energy industries might suffer harm if a stay were granted of the U.S. Environmental Protection Agency's ("EPA") Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 80 Fed. Reg. 64,662 (Oct. 23, 2015) ("Clean Power Plan").

7. In preparation for this declaration, I have become familiar with: (a) the Clean Power Plan; (b) the Petitions for Stay; and (c) the declarations thereto. In addition, I am acquainted with the other documents cited in this

declaration.

8. Petitioners have requested a stay of the Clean Power Plan. Petitioners claim that their affected industries will be immediately harmed by the Clean Power Plan. I do not believe that the Clean Power Plan will cause significant retirements or investments during the litigation period given the uncertainty about state plans and the long lead-time available. But to the extent Petitioners' claims of harm are correct, AWEA and SEIA's members face a reciprocal harm from the grant of a stay because wind and solar energy are a substitute for coal-fired power plants.

9. In recent years, wind and solar energy have made significant gains and have achieved historic levels of deployment. The United States has an installed wind capacity of 69,471 MW with over 13,250 MW of wind currently under construction and an additional 4,100 MW in the advanced stages of development. Likewise, the United States has an installed solar capacity of 22,700 MW with over 5,200 MW of solar under construction and an additional 11,400 MW in the advanced stages of construction. Respondent, Enel Green Power North America, Inc. currently operates approximately 28.4 MW of solar in Nevada, and 2.5 MW of solar in Vermont. Across the wind industry, nearly 3,200 MW of wind projects have not yet started construction but have secured long term PPA agreements for at least a percentage of the project's capacity. Approximately 560 MW of wind projects have been announced to proceed under direct utility ownership. Nearly 400 MWs of additional wind capacity have placed firm turbine orders but do not currently have an offtake agreement

secured. Therefore, a total of 17,400 MW of wind projects are either under construction or are in the advanced stages of project development. These projects are reasonably expected to be completed in the near term. This investment in wind is being driven primarily by the improved economics of wind energy.

10. Last year, more than $8.5 billion was invested in new wind and $17.8 billion was invested in new solar energy projects in the U.S. Wind project debt provided totaled $2.7 billion. Tax equity investments totaled $5.8 billion. These investments were made by domestic and foreign financial institutions (banks, insurance companies etc.), energy companies, other corporations, and hedge funds. Most, if not all, of the investors in renewable energy projects invest capital around the world. Policy uncertainty results in business and investment uncertainty. The uncertainty regarding the form of state plans is clouding the investment outlook from the Clean Power Plan. By delaying the development of state plans, a stay would further extend this period of uncertainty. Investors do not like uncertainty and can take their capital and invest it elsewhere in response, which will harm the domestic renewable energy industry by making it more difficult to find affordable project-level debt and equity, including construction loans, project debt, and project equity, which are essential to getting projects, including those with signed power purchase agreements, from development into construction and then operations.

11. Currently, American wind power supports 73,000 well-paying jobs, including nearly 20,000 manufacturing in one of the fastest-growing U.S. manufacturing

sectors.[1] Likewise, American solar power supports over 200,000 well-paying jobs, including nearly 32,500 in manufacturing. Wind and solar power support jobs in all 50 states, including sought-after manufacturing jobs at more than 1150 factories in 48 states. At the same time, the costs of wind energy have decreased by more than two-thirds over the past five years. In light of these domestic developments in the US, as well as the international context, including the United Nations Framework Convention on Climate Change negotiations, investors are increasingly focused on renewable energy.

12. The Clean Power Plan will further incentivize the U.S. to continue the transition to renewable and other clean energy sources. While there are many ways that the Clean Power Plan will do so, the final rule includes a new program, the Clean Energy Incentive Program, designed to incentivize near-term development of renewable energy sources, as well as certain demand-side energy efficiency projects. Also known as the CEIP, the program will reward developers that are able to complete certain eligible renewable energy facilities during the two-year period before the Clean Power Plan's compliance period goes into effect in 2022. It is important to note that the litigation before the D.C. Circuit is expected to conclude before developers start to make investments that may receive CEIP credits. This means that CEIP investments will not cause competitive harm to movants before the case has been resolved.

13. The Clean Power Plan sets forth a basic framework for how the CEIP can incentivize early investments in renewable energy projects. Under the CEIP,

---

[1] AWEA PTC White Paper at p. 6 (2014).

the EPA will provide additional credits to developers of certain types of renewable projects that commence after states submit a final plan. Specifically, under the CEIP, a developer of an eligible wind or solar power project will receive one emissions-reduction credit from the state and one matching credit from the EPA for every 2 megawatt-hours that the project generates in 2020 or 2021.

14. Under the CEIP, the EPA will provide matching credits up to an amount that represents the equivalent of 300 million short tons of carbon dioxide emissions. These credits will be tailored to work within the state programs, regardless of whether they are using rate- or mass-based standards. The EPA indicated in the final rule that it intends to reserve a portion of this pool for eligible wind and solar projects; however, the EPA has not yet determined how the pool will be divided.

15. States interested in participating in the CEIP must meet certain requirements. Such states must include in their initial state plan submittals, due on Sept. 6, 2016, a nonbinding statement of intent to participate in the program, regardless of whether that submittal details a final plan or seeks an extension for doing so. States can also submit final plans as early as Sept. 6, 2016 and as late as Sept. 6, 2018. The EPA plans to allocate all federal matching credits by Sept. 6, 2018.

16. Information provided by the EPA to date on the CEIP suggests that the program will provide a meaningful incentive for renewable project developers to undertake new projects in participating states. While project developers may need to wait several years before they can reap the rewards of the CEIP,

developers are already engaging the EPA and state policy makers to ensure that the program is designed and implemented to increase early investment in renewables. In fact, renewable project developers are already positioning themselves to take advantage of CEIP incentives.

17. For the many renewable energy developers, such as Enel Green Power North America, Inc. that are looking to take advantage of the CEIP program, it is critical that the program not be postponed by being stayed. If a stay were granted, the date for a state to elect to participate in the CEIP could be deferred. As there is likely to be at least 300 million short tons of early action credits for renewable projects, a postponement of the date on which states indicate if they want to participate in the CEIP could have serious consequences for renewable energy investment, sending a cloud of uncertainty if projects would ultimately be developed to meet the demand created by this program. Moreover, given the requirement that CEIP-eligible projects cannot commence construction until a final state compliance plan is submitted to the EPA (which can be as late as September 2018), project developers and other industry participants would also be harmed because it would delay the amount of time in which they would have to become operational in order to be online in time to earn the matching credits from the EPA in the eligible years of 2020-2022. In other words, if a stay lasts too long, it could be difficult for project developers to complete construction before the start of the period for accruing credit under the CEIP.

18. A stay would frustrate financier efforts to invest in these projects as well as

developer efforts to negotiate Power Purchase Agreements over the next couple of years as potential buyers may put decisions on hold pending more policy certainty. Respondent, Enel Green Power North America, Inc., and other renewable energy developers—not Petitioners—bear the financial risk of developing wind and solar projects. In Respondent's experience, site identification to commercial operation of a wind energy project can take from three to four years and cost approximately 1.7 million dollars per installed megawatt. It is crucial that sites are prepared and plans are developed for renewable energy projects that can help states comply with their future obligations under the Clean Power Plan. A stay would decrease the pipeline of projects under development and would make future compliance with the emissions targets required by the Clean Power Plan much harder. It could also frustrate industry efforts to retain employees in anticipation of this program.

19. The scope of these job losses could have impacts on the broader US economy as well. An analogy can be made to job losses that are related to uncertainty in tax policy with respect to wind energy. After the expiration of the Production Tax Credit in 2012, there was a drop from 80,700 wind-energy related jobs in 2012 to 50,500 jobs in 2013. This contributed to the close of two utility-scale blade manufacturing facilities and two turbine nacelle facilities during 2014. In addition, wind energy costs rose immediately thereafter as it took time for the industry to make up for these loses. There is reason to assume that the same would occur if a stay were granted.

20. Decarbonization of the electric grid is possible and the Enel Group has already made that a reality in Europe. As Italy's largest power company and Europe's second listed utility by installed capacity, the Enel Group is a leading integrated player in the power and gas markets of Europe and Latin America. It overseas power generation from a net installed capacity of almost 90 GW, distribution of electricity and gas through a network of over 1.8 million km, and delivery of energy to approximately 61 million customers. Over 47% of the power generated by Enel in 2014 was carbon free. Enel's low carbon commitments include: (1) by 2020, cutting CO2 emission intensity by 25% with respect to 2007 levels; (2) achieving carbon neutrality before 2050; (3) investing significantly in RES (more than 11 Bn€ of capex for over 9 GW of additional capacity during the period 2015-2019); and (4) researching and developing new environmentally friendly technologies. As the Enel Group has shown, with the right mix of low carbon investments, utilities and electric systems can be decarbonized without halting economic growth.

21. In conclusion, the grant of a stay would likely harm movant-intervenors, AWEA and the wind industry, through an interruption of the development of renewable energy resources that would occur if the Clean Power Plan is stayed, and this could have a broader impact to the U.S. economy.

that the foregoing is true and correct. Executed this 7th day of December, 2015, in

Andover, Massachusetts.

Signature

Michael I. Storch
Executive Vice President
Enel Green Power North America, Inc.

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

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ______

DECLARATION OF TED THOMAS, CHAIR, ARKANSAS PUBLIC SERVICE COMMISSION

I, Ted Thomas, declare as follows:

1. I am the Chair of the Public Service Commission of Arkansas ("APSC"). I have been Chair of the APSC since January, 2015 and was previously employed at the APSC as an administrative law judge for 7 years. As part of my duties, I have authority to monitor, track, and interact with stakeholders and regulators on the development and implementation of state and federal environmental rules impacting public utilities. The primary responsibility of the APSC is to set just and reasonable rates for utility service provided by regulated

utilities in Arkansas. Rates are based on the cost to provide service and regulations have a substantial impact on costs.

2. I have personal knowledge and experience to understand what steps Arkansas has taken and will likely need to take in response to the EPA's Section 111(d) Rule, including future resource planning for system reliability. In general, the Section 111(d) Rule could dramatically transform the way electric power will be generated and transmitted to consumers in Arkansas and throughout the United States. The ultimate cost of the rule will be determined by future price movement of natural gas, renewable energy resources, energy efficiency products and other commodities and products used in the generation and transmission of electric energy. The Rule could have devastating effects on consumers of electricity and on economic development investment necessary to create jobs. The Rule may require the construction of new power plants and associated infrastructure, the updating or decommissioning of existing power plants that are not fully depreciated, and the reduction in overall energy consumption by every single current and future consumer of electric power. In short, the Section 111(d) Rule will transform the American energy economy, and may devastate the economy.

3. Based on my work experience and position, I have determined that implementing the Section 111(d) Rule will be a complicated, time consuming, and

expensive endeavor, which will require the expenditure of substantial State resources, immediately, over the next calendar year and into the future.

4. Significant APSC resources have already been invested to understand and evaluate the proposed 111(d) Rule. APSC employees have spent hundreds of hours understanding the rule and preparing for implementation, including outreach to all Arkansas stakeholders, organizing stakeholder meetings and listening sessions, participating in regional collaborative sessions such as Mid-Continent States Environmental and Energy Regulators with other states and industry participants, attending EPA listening sessions and conference calls, and in-depth analysis of the impact of the Section 111(d) Rule on the state and regional systems. I estimate that since I have assumed my current position that 10%-15% of my time has been spent on issues related to the 111(d) Rule.

5. APSC employees have spent hundreds of hours modeling and reviewing modeling results for the likely compliance scenarios, and will spend additional time and resources modeling the changes made from the proposed to the final Section 111(d) rule. The purpose of this model is to forecast the cost of the changes in the MISO and SPP wholesale electricity markets to try to determine the cost to comply with the Section 111(d) Rule, and to compare the option of a state-only compliance plan with the option of a regional compliance plan. With input from stakeholders, engineers from the APSC assisted in building a model using the

"Electric Generation Expansion Analysis System (EGEAS)". Several model runs were completed, analyzed, and presented with our comments to the EPA. We also presented the modeling results in several different conferences with numerous stakeholders.

6. Based on my knowledge and experience, the Section 111(d) Rule represents an unprecedented infringement by the EPA on the traditional authority of the State of Arkansas to manage energy resources within our jurisdiction because the mandates of the Section 111(d) require APSC to undertake specific changes to how energy is provided to consumers or face devastating potential cost consequences. The Section 111(d) Rule also disrupts the well-settled division of authority over electricity markets under the Federal Power Act, and raises significant uncertainty about the role of the Federal Energy Regulatory Commission to ensure the reliability of electricity through the wholesale market.

7. Absent a stay from this Court, compliance planning must begin immediately. The system-wide changes necessary for compliance must be gradual to preserve reliability of the electric grid. Because compliance is calculated based on a rolling average, the longer Arkansas waits to begin compliance, the more expensive and difficult it will be to meet the requirements of the Rule.

8. Absent a stay from this Court, evaluation of specific compliance measures, such as new facilities or retirements, must also begin immediately. The

lengthy application and approval process for utilities to construct, upgrade, or retire facilities to comply with the Section 111(d) Rule, as well as the in-depth evaluation of public necessity and convenience for each facility, requires utilities to plan and submit applications for upgrades almost immediately after publication of the final Section 111(d) Rule in order to have equipment constructed, upgraded, or decommissioned before the compliance period begins in 2020. The Section 111(d) Rule also requires decisions to be made on future price projections which exposes Arkansas ratepayers to great risk should prices be different that the projections.

9. Absent a stay from this Court, the APSC will need to spend hundreds if not thousands of hours and tens of thousands of dollars over the next calendar year as a direct result of the Rule. The expenditure of these resources must begin immediately.

10. Arkansas utilities are members of two Regional Transmission Organizations ("RTOs") that exist to plan and manage the electric transmission grid. The planning and construction process for new transmission infrastructure is 5 to 7 years. The 2018 plan submission deadline, the 2020 early action benefit deadline and the 2022 plan implementation deadline all require beginning of action if new transmission infrastructure procured by existing processes is to be included in an implementation plan. The time required to plan and construct new transmission assets also pushes forward the time that price estimates must be made,

further increasing the risk to consumers of unexpected prices. Regulators are faced with a choice of requiring utilities to invest large sums of money on trasmmission infrastructure based on projections of prices in 5-10 years, or delaying approval of transmission investment which takes some generation options off the table. Absent a stay from this Court, the Section 111(d) Rule places significant risk on Arkansas consumers if the best estimates of future prices turn out to be wrong. The Section 111(d) Rule could also severely threaten reliability and increase the cost of electricity by forcing Arkansas to move immediately toward reliance on a limited number of fuel sources based on the best guess of what prices will be. The risks associated with this type of system-wide transformation will begin in the next year and require decisions to be made earlier based on longer term forecasts unless the Rule is stayed.

11. Changes made for the sake of compliance with the Section 111(d) Rule immediately and over the next calendar year could be irreversible and will impact the electric grid for decades. Alternatively, the State of Arkansas can wait on the outcome of litigation and find that some compliance options are foreclosed because there is insufficient time to construct transmission assets. This "catch-22" places substantial risk on Arkansas ratepayers. System planning is typically based on the 30-40 year lives of generation and transmission facilities. Building, redesigning, and adjusting power generation facilities takes years, and decisions

made in these areas are often irreversible once they are made. For example, the decision to prematurely retire an electric generating unit could have significant consequences for system reliability and may unnecessarily increase costs to ratepayers for decades to come.

12. Absent a stay from this Court, various options for implementation of the Section 111(d) Rule will require legislative and constitutional changes on the state level that may permanently alter the daily operation of utilities. Specifically, the Section 111(d) Rule includes control measures outside of the physical location and control of electric generating units, such as end-use energy efficiency (reduced energy use by electricity consumers), demand response (usage changes according to instantaneous market and load-profile changes), and increased distributed generation (such as small residential renewable installations). Arkansas would have to immediately set in motion the chain of events, including statutory changes, larger investment in customer-side behavior, and further rate restructuring, in order for these compliance options to contribute to the Section 111(d) Rule's emission reduction targets. Alternatively, Arkansas could wait and not pursue statutory and constitutional changes and later discover that it was disadvantaged by the delay because of the movement of future prices and the extended planning periods for large scale utility operations.

13. To attempt to comply with the Section 111(d) Rule, Arkansas will seek a path forward as if each of a number of alternative suppliers of energy will turn out to be the least cost to Arkansas ratepayers. Arkansas will attempt to remove any non-price barrios for new natural gas units and infrastructure, solar facilities and necessary transmission facilities, wind facilities and transmission facilities, combined heat and power, demand response, energy efficiency targeted to low income areas as required by a part of the Section 111(d) Rule, and any other such options made available by technological improvements. Each will require review of current law and possible legislation or constitutional amendment relating to governmental financing or other incentive programs. Undertaking these measures will seriously disrupt the State's sovereign priorities, which would otherwise be devoted to addressing other pressing issues of public concern.

14. The State of Arkansas is required under Section 111(d) Rule to make significant changes to what sources are used to provide electric energy and how it regulates providers of electric energy. These decisions will necessarily involve a large capital investment, eminent domain issues associated with major transmission investment, significant statutory revisions and reliance upon projections of costs of numerous products and commodities. Absent a stay from this Court, these decisions will be made in an atmosphere of uncertainty in which the initial decisions will impact and limit later decisions. Options might be

impaired by the passage of time and commitments made too soon might prove to be poor choices. The most if not all of the financial risk associated with the decisions will be borne by the ratepayers of Arkansas.

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

Executed on 10/22/2015

Ted Thomas

ACKNOWLEDGMENT

STATE OF ARKANSAS

COUNTY OF PULASKI

On this the 22nd day of October, 2015, before me, Karen R. Wesson, the undersigned officer, personally appeared Ted Thomas, known to me to be the person whose name is/are subscribed to the within instrument and acknowledged that he/ executed the same for the purposes therein contained.

In witness whereof, I hereunto set my hand and official seal.

Karen R. Wesson

Notary Public

Printed Name: Karen R. Wesson

My Commission Expires:

KAREN R. WESSON
Notary Public-Arkansas
Jefferson County
My Commission Expires 09-16-2024
Commission # 12400984

9-16-2024

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

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ________

Declaration of Brandy Wreath
Public Utility Division
Oklahoma Corporation Commission

Pursuant to 28 U.S.C. § 1746, I, Brandy Wreath, declare and state that the following is true and correct and is based on my own personal knowledge.

1. I am the Director of the Public Utility Division (the 'Division") of the Oklahoma Corporation Commission ("OCC"), a position I have held since 2012. In this position, I am responsible for administering and enforcing the State's regulation of public utilities, including electric utilities, and for advising the OCC on matters relating to the regulation of electric utilities and electric service. A primary responsibility of the Division is assuring reliable utility service at the lowest reasonable cost. Division staff investigates and makes recommendations on matters such as establishment of rates or rate adjustments, changes in terms of services, and transfers of utility ownership.

2. The OCC is currently expending substantial resources-in terms of money, personnel, effort, and administrative focus-to comply with EPA's proposed regulations for existing power plants under Section 111(d) of the Clean Air Act (the "EPA Power Plan").

3. OCC staff participates in meetings regularly to coordinate regulatory responses to the EPA Power Plan with other components of the Oklahoma government, including the Oklahoma Secretary of Energy and Environnlent, and the Oklahoma Department of Environmental Quality. This coordination is necessary because the EPA Power Plan touches practically every aspect of electricity production, distribution, and consumption and therefore reaches across agency jurisdictional boundaries. As far as I am aware, this required degree of coordination to accommodate a federal rule affecting the utility sector is unique, and it is, with respect to the activities required of OCC, unprecedented.

4. OCC staff participates in stakeholder meetings regularly with persons and entities affected by the EPA Power Plan, including utilities and groups representing energy consumers.

5. OCC staff is working continuously with the Southwest Power Pool ("SPP"), which is the regional transmission organization for Oklahoma and surrounding states, to evaluate the actions necessary to accommodate the EPA Power Plan, to plan infrastructure projects that will be necessary to accommodate the EPA Power Plan, and to coordinate other activities respecting the EPA Power Plan. Currently, three full time equivalent Division employees spend all or nearly all of their time working with the SPP on these activities in addition to the other transmission related issues.

6. Oklahoma utilities are engaged currently in planning to accommodate the EPA Power Plan, and the Division is working closely with them to ensure that their contemplated actions satisfy Oklahoma law, are properly coordinated with other actions affecting power supply and delivery, satisfy all relevant reliability requirements, and provide good value to ratepayers. Oklahoma utilities, as well as other power suppliers to Oklahoma consumers, are contemplating and making decisions currently regarding infrastructure changes necessary to respond to the EPA Power Plan that will be difficult or impossible to reverse once these

decisions have been made.

7. Compliance with EPA environmental plans has already been a topic of at least one recovery hearing before the OCC. Recovery hearings determine which expenditures utilities may charge to ratepayers. Recovery hearings generally involve numerous intervenors-including environmental organizations-and weeks-long hearings before an Administrative Law Judge. Months of work, in terms of person-hours, is required to prepare for this type of hearing. OCC's fees for outside experts alone amount to hundreds of thousands of dollars for these types of hearings.

8. Any OCC rule or order that reflect measures to accommodate the EPA Power Plan will impose costs on the Division for years to come, due to its monitoring and enforcement roles.

9. Numerous OCC personnel and outside contractors are currently involved in activities regarding the EPA Power Plan. This includes multiple in-house experts with expertise in accounting, economics, financial analysis, and law. I personally spend numerous hours per week working on matters relating to the EPA Power Plan. The time that OCC personnel spend on matters relating to the EPA Power Plan is time that they are unable to devote to other agency priorities; as a result, OCC has been unable to devote the manpower that it would like to other priorities.

10. At the same time, being aware that the manpower necessary to accommodate the EPA Power Plan will balloon in coming months, OCC has assigned personnel to complete tasks that would be due in those months ahead of schedule. This too limits the OCC's ability to address other responsibilities.

11. Division staff has attended and will continue to attend numerous conferences regarding the EPA Power Plan so that the OCC is best able to meet the challenges of the EPA Power Plan. This comes at a cost to the OCC, in tens of employee time and travel expenses.

12. OCC has no choice but to begin activities now to accommodate the EPA

Power Plan. This is due to the EPA Power Plan's aggressive and unrealistic deadlines, the extent of the activities that will be required to accommodate the EPA Power Plan, the long lead time required to make and execute decisions regarding electric infrastructure, and the magnitude of the changes.

13. For example, determining the need for additional or new transmission capacity is a years-long process involving numerous stakeholders, and once that need is identified, another six to eight years is typically required for major projects to reach completion and be integrated into the grid.

14. If the OCC were not taking such actions at this time to prepare for the EPA Power Plan, it would not be able to accommodate anything like the EPA Power Plan anywhere close to the schedule.

15. The same is true of the utilities regulated by the OCC. Currently they are engaged in planning and other activities, as well as making investment decisions, to attempt to comply with or accommodate the EPA Power Plan.

16. Uncertainty relating to the EPA Power Plan has complicated the planning and execution of infrastructure projects. For example, the EPA Power Plan places investments in transmission capacity at risk because plant retirements due to the EPA Power Plan may render that capacity unnecessary. Similarly, the EPA Power Plan has made power plant owners reluctant to perform upgrades at this time, due to the risk that those plants may have to be retired to accommodate the EPA Power Plan.

17. The Division is concerned deeply about the EPA Power Plan's impact on the health and welfare of Oklahoma residents. The EPA Power Plan's heavy emphasis on natural gas comes at the expense of fuel diversity, and lack of diversity increases the risk and impact of supply disruptions and price volatility. As part of its public mission, the OCC is attempting to address this issue, which EPA has ignored.

18. On August 3, 2015, the EPA announced the Final Rule under which it intends to implement its Clean Power Plan. I have reviewed that Final Rule and have concluded that it confirms the necessity for the actions I have described above, by making firm all compliance

requirements, including emissions-reduction targets, state options and deadlines for state action and, as a result, increases the amount of State resources that have to be expended, as State agencies pursue the time-consuming work of evaluating and responding to the final terms of the EPA Clean Power Plan.

I declare under penalty of perjury under the laws of the United States of America that the above and foregoing is true and correct to the best of my knowledge.

Executed on this 11th day of August, 2015.

Brandy Wreath

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

State of West Virginia, et al., Petitioners, **v.** **United States Environmental Protection Agency, et al.,** Respondents.	Case No. 15-1363 (and consolidated cases)

**DECLARATION OF CRAIG A. WRIGHT,
DIRECTOR OF AIR RESOURCES DIVISION, NEW HAMPSHIRE
DEPARTMENT OF ENVIRONMENTAL SERVICES**

I, Craig A. Wright, declare:

1. I have been employed at the New Hampshire Department of Environmental Services ("DES") in the field of air pollution control since January 1988. Since September 2013, I have served as the Director of the Air Resources Division ("Air Director") at DES. My educational background consists of a B.S. in Chemical Engineering from the University of New Hampshire.

2. During my career at DES, I have become very familiar with the federal Clean Air Act and its regulation of stationary sources of air pollution, including Sections 111(b) and 111(d). My specific job assignments at DES have

included working as a Permit Engineer, Permit Bureau Administrator, Environmental Programs Manager (Deputy Director) and currently serving as the Air Director. I have been directly involved in the planning, development and implementation of state plans under the Clean Air Act, including state implementation plans under Section 110 to comply with the National Ambient Air Quality Standards and also Section 111(d) State Plans for other source categories, including Municipal Waste Combustors (MWCs), Commercial/Industrial Solid Waste Incinerators (CISWI) and Hospital/Medical/Infectious Waste Incinerators (HMIWI).

3. In my current capacity as DES Air Director, I am responsible for the oversight and implementation of federal Clean Air Act programs on behalf of the State of New Hampshire. In addition, I have been directly involved in the state's activities as part of the Regional Greenhouse Gas Initiative ("RGGI"), including the 2012 "program review" of RGGI that resulted in a number of policy changes to the program. DES is ultimately responsible for the day-to-day mechanics of implementing the RGGI Program in New Hampshire, including interactions with RGGI, Inc. For example, I oversee and manage the DES program staff that participates in RGGI Program Committees conference calls and work sessions. I, on occasion, serve on behalf of the DES Commissioner as an "alternate director" on the RGGI Executive Committee. I also routinely consult with DES

Commissioner Thomas S. Burack and Public Utilities Commission ("PUC") Commissioner Robert R. Scott, both members of the RGGI Board of Directors, on RGGI program and policy matters.

4. Ultimately, DES will be responsible for development and implementation of a State Plan to comply with the United States Environmental Protection Agency's ("EPA") final rules regarding greenhouse gas emissions from existing power plants under Section 111(d) of the Clean Air Act (the "Section 111(d) Rule"), otherwise known as the Clean Power Plan.

5. The purpose of this declaration is to provide my understanding of New Hampshire's and the RGGI states' readiness to comply with the administrative and procedural requirements of the Section 111(d) Rule.

Addressing Climate Change Pollution in New Hampshire

6. New Hampshire residents are already experiencing the effects of a changing climate on our environment: more intense rainstorms that wash out roads and culverts, and that damage homes, businesses, and wastewater and drinking water facilities; and gradual warming that supports larger tick populations that infect people and wildlife with disease and that negatively affects our cold-weather industries and maple-syrup producers. In addition to adapting to a changing climate we must also take concrete steps to reduce carbon emissions from all

sectors, including the electric utility sector which represents about one-third of carbon dioxide emissions in the United States, according to EPA.

7. To address the causes and impacts of climate change, former NH Governor John Lynch created the Climate Change Policy Task Force in December 2007. The Task Force was chaired by DES Commissioner Burack and composed of 29 members, who represented a variety of geographic regions as well as interests, and possessed a significant amount of experience in energy, climate and policy issues. The Task Force oversaw the development of the 2009 NH Climate Action Plan, which expresses a vision for the state's energy, environmental, and economic development future and includes recommendations for maximizing energy efficiency, increasing use of renewable fuels, protecting natural resources, and adapting to existing impacts of our changing climate. The plan recommendations were selected to support the goal of reducing greenhouse gas emissions to 80 percent below 1990 levels by 2050 while providing significant economic opportunities across the state.

8. More recently, Governor Margaret Wood Hassan announced that New Hampshire would sign onto the Under 2 MOU, a global compact among cities, states, and provinces worldwide to limit the increase in global average temperature to below two degrees Celsius.

Section 111(d) Rule

9. I have closely followed the development of the Clean Power Plan since its original proposal in June of 2014. Since that time, my direct involvement includes reading significant portions of both the proposed and final rules, as well as reading EPA guidance materials and technical support documents. In addition, I have participated in numerous conference calls with EPA, the RGGI States, Environmental Council of the States, and the Georgetown Climate Center on various aspects of both the draft and final versions of the Clean Power Plan. I have participated directly in the drafting and filing of comments on the proposed rule by DES, RGGI, and the Georgetown Climate Center. These efforts included participating in conference calls, providing comments on draft language and consulting with DES leadership and the Governor's Office on various aspects of the Clean Power Plan. Finally, I have attended and participated in several meetings with other RGGI states' staffs to discuss various aspects of the Clean Power Plan and its implementation.

10. I have reviewed the final Section 111(d) Rule. The rule establishes carbon dioxide (CO_2) emission performance rates for reducing emissions at electric generating units. It also specifies guidelines for states to use in developing, submitting, and implementing state plans to achieve the rule's emission rate goals.

In the final rule, EPA promulgated subcategory-specific CO_2 emission performance rates that reflect the "best system of emissions reductions… adequately demonstrated" (BSER) from the power sector. The final rule also sets out state rate-based and mass-based CO_2 goals to provide states with flexibility in developing their plans, including utilizing allowance trading programs and other measures. New Hampshire's rate-based goal for 2030 is 858 pounds-CO_2 per megawatt-hour by 2030, and its mass-based goal for 2030 is about 4 million short tons of CO_2 per year, which is about 14% below 2012 power sector emissions.

11. The Section 111(d) Rule requires that states submit compliance plans or initial submittals requesting an extension to EPA by September 6, 2016. States that are granted an extension must submit their compliance plans by September 6, 2018. The Section 111(d) Rule also permits states to join together and submit joint compliance plans in lieu of state-specific plans. The compliance period begins January 1, 2022, giving states seven years from now to prepare to comply. The Section 111(d) Rule also provides for considerable flexibility in the setting of states' interim goals, including the opportunity to achieve the final 2030 goals at a pace that each state finds appropriate.

Regional Greenhouse Gas Initiative

12. The Regional Greenhouse Gas Initiative ("RGGI") is a market-based program to reduce greenhouse gas emissions from the electric power sector. RGGI

is a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont (together, the "RGGI States").

13. The program requires power plants to possess a tradable CO_2 allowance for each ton of CO_2 they emit. The program was developed under a Memorandum of Understanding signed by initial member state governors in December 2005, followed by issuance of a model rule in August 2006. All states completed their legislative and regulatory processes by the end of 2008, allowing for implementation by the RGGI States in 2009.

14. In New Hampshire, former Governor Lynch signed the RGGI Memorandum of Understanding on December 20, 2005. RGGI authorization legislation (HB 1434) was introduced on January 2, 2008, approved by the NH General Court on June 5, 2008 and signed into law by Governor Lynch on June 11, 2008. DES initiated the formal rulemaking process on August 21, 2008 and adopted interim regulations implementing RGGI on October 1, 2008 and final regulations on April 3, 2009. In all, approximately 16 months elapsed from the time the legislation to adopt RGGI was proposed until the law was enacted and the implementing regulations were adopted.

15. RGGI is grounded in each state's own statutory and regulatory authorities. Each state's laws and regulations establish "CO_2 Budget Trading

Programs" that limit emissions of CO_2 from electric power plants, create CO_2 allowances, determine appropriate allowance allocations, and provide for participation in CO_2 allowance auctions. In New Hampshire, RGGI is grounded in statute and regulations. N.H. REV. STAT. ANN. § 125-O:20-29; N.H. CODE ADMIN. R. ENV-A 4600, 4700, 4800.

16. Under contracts with the RGGI States, RGGI, Inc., a non-profit corporation, administers regional auctions to sell CO2 allowances. States sell nearly all emission allowances through auctions and invest most of the proceeds—over $2 billion through March 2015—in energy efficiency, renewable energy, and other consumer benefit programs. See Press Release, CO2 Allowances Sold for $6.02 in 29th RGGI Auction; Total Proceeds for Reinvestment Now Exceed $2 Billion, September 11, 2015, at http://www.rggi.org/docs/Auctions/29/PR091115_Auction29.pdf

17. Collectively, the states' CO_2 Budget Trading Programs establish an annually declining cap on CO_2 emissions from the power sector within the RGGI States. The RGGI program, in conjunction other state clean energy polices and other energy market factors, has helped the RGGI States reduce carbon dioxide emissions by approximately 40 percent since 2005.

2012 Program Review

18. The RGGI States completed a two-year comprehensive program review in 2012. Following the review, the states established a new regional CO_2 budget that lowered the cap on emissions to 91 million tons in 2014, a reduction of 45 percent from the original cap. Under the program changes, the cap will decline 2.5 percent each year from 2015 to 2020. To implement the newly lowered cap, the RGGI States then revised their own CO_2 Budget Trading Programs through their state-specific legislative and regulatory processes.

19. New Hampshire and the RGGI States successfully adopted statutory and regulatory changes in time for the lower regional cap to be in place for 2014 regional auctions. In New Hampshire, RGGI revision legislation was introduced as a non-germane amendment to existing House Bill 306 on February 26, 2013 and passed the NH House on March 20, 2013. The NH Senate passed the bill with amendments on May 23, 2013. The NH House subsequently concurred with the Senate amendments on June 5, 2013 and the bill was signed into law by Governor Hassan on July 15, 2013. The revised statutory changes authorized the lowering of the state share of the regional cap, adoption of a revised price protection mechanism, and additional offsets categories. DES subsequently initiated the formal rulemaking process on September 9, 2013 and received final approval from the Joint Legislature Committee on Administrative Rules (JLCAR) on November

22, 2013 with a rule effective date of January 1, 2014. *See* N.H. REV. STATS. ANN. §§ 125-O:20-29; N.H. CODE ADMIN. R. ENV-A 4600, 4700, 4800.

20. As when RGGI was adopted, New Hampshire successfully implemented the 2012 Program Review changes, despite the irregular calendar (generally only in session from January through June in any given calendar year) of the New Hampshire legislature.

21. The RGGI States' successful 2012 program review demonstrated their ability to work together to set new goals for regional emissions reductions while timely amending their individual state programs to reflect those goals. *See* Press Release, RGGI States Make Major Cuts to Greenhouse Gas Emissions from Power Plants, Jan. 13, 2014, *at* http://www.rggi.org/docs/PressReleases/PR011314_AuctionNotice23.pdf.

RGGI States and the Section 111(d) Rule

22. In their comment letters on the proposed Section 111(d) Rule, the RGGI States offered their support of the rule's framework, which provides states with flexibility to craft plans to meet state-specific emissions targets. The RGGI States also lauded the provisions of the proposed rule encouraging states to work together to develop multi-state compliance plans. *See* RGGI States' Comments on Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (November 5, 2014); RGGI States' Supplemental

Comments on Proposed Clean Power Plan (Dec. 12, 2014); *see also* NH State Comments on Proposed Clean Power Plan (Dec. 1, 2014).

23. Under the final Section 111(d) Rule, states will be required to demonstrate compliance by January 1, 2022, and states may set their own interim goals between 2022 and 2029. The RGGI States are working together to consider submitting one multi-state compliance plan or individual state plans that rely on RGGI as a compliance mechanism. The RGGI States currently have a plan for completing this multi-state effort in a timeframe that will allow for timely submission of state plans.

24. For example, DES has already held a stakeholder meeting on November 20, 2015 to gather public input on implementation of the Clean Power Plan. As part of the outreach process, DES provided public notice of the stakeholder meeting via a newspaper of statewide circulation and the DES and RGGI, Inc. websites. In addition, DES provided direct notification to affected power plants, towns where power plants are located, selected additional towns that have vulnerable, low income or minority communities (per the environmental justice requirements of the Clean Power Plan), sister governmental agencies, state legislators and other potentially interested parties. In addition, DES also participated in a regional RGGI stakeholder meeting on November 17, 2015 hosted by RGGI, Inc. DES and RGGI, Inc. have provided stakeholders with materials via

the RGGI, Inc. website on key items for discussion including: State Plan Approaches, Post 2020 CO_2 Emissions Reductions, RGGI Flexibility Mechanisms, RGGI Regulated Sources, Promoting Renewable Energy and Energy Efficiency, and Broadening the RGGI Market/Trading Partners. See http://www.rggi.org/docs/ProgramReview/2016/11-17-15/Key_Discussion_Items_11_17_15.pdf. Finally, DES has provided briefings on the final Clean Power Plan to a number of interested parties including environmental interest groups, professional engineering organizations, legislative oversight committees, biomass interests, and the NH Congressional Delegation. The RGGI states plan to hold at least two other stakeholder meetings to ensure that at least one meeting will be held in each of the regional transmission organizations (ISO-NE, NYISO and PJM) located within the RGGI States.

25. The RGGI State environmental agencies, including DES, have in place the necessary authorities and administrative procedures to assure timely compliance with federal Clean Air Act rules, including the Section 111(d) Rule. In this regard, each of the RGGI States has decades of experience complying with other federal Clean Air Act rules that require comprehensive state planning to achieve compliance, including state implementation plans to achieve the National Ambient Air Quality Standards for criteria air pollutants. *See* 40 C.F.R. Part 52, Subpart EE (New Hampshire).

26. New Hampshire has a demonstrated history of successfully adopting a program to regulate and reduce carbon dioxide pollution from the electric generating sector and subsequently amending the program. As noted above, New Hampshire successfully implemented the RGGI program in 2008 and significant program amendments in 2013. Both of these events required both legislative approval and a formal administrative rules adoption process. As noted above, the NH Legislature is only in session for approximately six months (typically January through June) per calendar year and with very limited bill filing windows. Despite these limiting factors, New Hampshire has in the past been successful in adopting policies (in the form of statutes and implementing regulations) consistent with or similar to the Clean Power Plan.

27. Based on the New Hampshire's experience complying with federal Clean Air Act rules and New Hampshire's and the RGGI States' successful implementation of the RGGI program, I am confident that New Hampshire and the RGGI States are well equipped and will be able to comply with the state planning requirements of the Section 111(d) Rule in a timely fashion. I believe that under the Clean Power Plan, EPA has provided states with sufficient time to adopt a compliant and approvable state plan.

28. New Hampshire, working with the other RGGI States will likely file an initial submittal with a request for extension by September 6, 2016, as provided

for in the Clean Power Plan. I believe that New Hampshire will be well positioned to obtain an extension from EPA as we are actively working on evaluating state plan options with respect to a multi-state approach, undertaking a significant public outreach effort including consideration of environmental justice communities, and planning to utilize the additional time to complete necessary plan components, including revised legislation and administrative rules, as needed. As a final note, I anticipate that New Hampshire will be able to comply with the Clean Power Plan by submitting an approvable final plan to EPA by September 6, 2018.

Executed on this 1st day of December 1, 2015.

Craig A. Wright

____

Craig A. Wright, Director