No. 05-848

IN THE

Supreme Court of the United States

ENVIRONMENTAL DEFENSE, ET AL.,
Petitioners,
v.

DUKE ENERGY CORPORATION,
Respondent.

On Writ of Certiorari to the United States Court of Appeals for the Fourth Circuit

BRIEF *AMICI CURIAE* OF THE AMERICAN PUBLIC POWER ASSOCIATION AND THE NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION IN SUPPORT OF RESPONDENT DUKE ENERGY

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All parties consent to the filing of this brief.[1]

STATEMENT OF INTEREST OF *AMICI CURIAE*

Created in 1940 as a non-profit, non-partisan organization, *amicus curiae* the American Public Power Association (APPA) is the service organization for the nation's more than

[1] No party or its counsel authored this brief in whole or in part nor made a monetary contribution to *amici* for the preparation or submission of it. This brief is filed with the written consent of all parties pursuant to Rule 37.3(a). Copies of the requisite consent letters have been filed with the Clerk.

2,000 community-owned and community-operated electric utilities that serve more than 43 million Americans in 49 states or approximately 14 percent of the nation's electricity customers. 1,400 of the 2,011 public power systems in the United States serve communities with populations of 10,000 or fewer. Thirty percent or 29,175 MW [2] of APPA's members' power generating capacity is coal-fired.

Although the vast majority of the public power systems is owned by cities and towns, a number of counties, public utility districts and even a handful of states have public power systems. Most public power systems, especially the smaller ones, are governed by a city council, while others are overseen by an independently elected or appointed board.

Public power has a strong environmental protection record and a reputation for reliable and affordable power service. APPA's mission is to assist its members in ensuring that adequate, reliable electricity is available to their customers at a reasonable price while protecting the environment.

Amicus curiae the National Rural Electric Cooperative Association (NRECA) was formed in 1942 by the nation's rural electric cooperative leaders dedicated to electrifying vast regions of the country and providing reliable and affordable electric power through electric cooperative entities. Today, NRECA serves as the national service organization for 930 not-for-profit rural electric cooperatives that provide electric service to 39 million Americans in 47 states. Each electric cooperative is incorporated as a private entity in the state in which it resides and has a legal obligation to provide

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[2] "Megawatt" or "MW" is used to describe the electric generating (output) capacity of a facility. Another measure of capacity used by utility engineers describes the capability of a unit to burn fuel (*i.e.*, its heat input capacity) and is expressed in terms of million British Thermal Units (mmBtu) per hour. Because unit emissions are directly related to the amount and type of fuel burned in that unit, a unit's capacity to emit is directly related to the unit's heat input capacity.

reliable electric service to its customer-members. Collectively, cooperatives serve all or portions of 2,500 of the nation's 3,128 counties and their service areas cover 75 percent of the U.S. landmass.

The scarcity of reliable and affordable electric power in many regions of the United States in the late 1960's created a need for cooperative self-generation of electric power. Today, sixty-five rural electric generating and transmission cooperatives (G&Ts), which are owned by the distribution cooperatives they serve, generate and transmit power to 670 of the 865 distribution cooperatives. Overall, cooperative G&T generation produces 41 percent of all distribution cooperative needs. The need to provide reliable, primary (baseload) and affordable electric power effectively dictated coal as the fuel of necessity rather than natural gas and nuclear power. Presently, 80 percent of NRECA's members' cooperative generation or 23,000 MW is coal-fired. The remaining distribution cooperatives receive power directly from other generation sources within the electric utility sector, a significant portion of which also originates from coal-fired generation.

NRECA's cooperative members are dedicated to offering their member-consumers a broad array of electric generation choices including "green power." Today, about two-thirds of the cooperatives offer a green or renewable power option. The majority of this generation is by wind or biomass.

Amici curiae, who are owned by their communities or customers, represent smaller electric generating entities.[3] Collectively, *amici curiae* comprise a significant portion of the electric generation and distribution industry which, in turn, serves over 25 percent of electricity customers and over 80 percent of the landmass in the United States. For this

[3] Over 95 percent of the members of APPA and NRECA are considered "small entities" under the Small Business Regulatory Enforcement Fairness Act of 1996, 5 U.S.C. 801 *et seq.*

reason, *amici curiae* provide a unique and invaluable perspective on the effect that the Environmental Protection Agency's (EPA's) enforcement interpretation of New Source Review (NSR) can have on the ability to supply reliable and affordable electric service throughout the United States.

SUMMARY OF ARGUMENT

Requiring NSR permitting under EPA's NSR enforcement interpretation when a small electric utility merely takes a boiler offline to undertake the repair or replacement of a broken component without increasing the unit's permitted capacity to emit (*i.e.*, its emissions rate, unaffected by hours of operation, or its hourly maximum achievable emissions rate) is inconsistent with the Clean Air Act, 42 U.S.C. 7401 *et seq.* (CAA). [4] It also would be costly, potentially financially crippling and environmentally unnecessary for small public and rural electric generating systems that service a significant portion of the U. S. population and landmass. Accordingly, to ensure that these smaller utilities can continue to meet their duty to provide reliable and affordable electric service, this Court should affirm the decision of the United States Court of Appeals for the Fourth Circuit in *United States v. Duke Energy Corp.*, 411 F.3d 539 (4th Cir. 2005).

[4] *Amici curiae*'s primary purpose in filing this brief is not to repeat the reasons why EPA's position is inconsistent with the letter and the spirit of the CAA. Instead, *amici curiae* can provide the Court with insight into the practical effect of the position advocated by Petitioners and EPA.

ARGUMENT

I. REQUIRING NSR PERMITTING, A LENGTHY AND COSTLY PROCESS, FOR REPAIRS THAT DO NOT INCREASE A FACILITY'S ACHIEVABLE HOURLY EMISSIONS RATE WOULD SERIOUSLY IMPEDE THE ABILITY OF PUBLIC AND RURAL COOPERATIVE GENERATING SYSTEMS TO SUPPLY RELIABLE AND AFFORDABLE ELECTRIC POWER.

A. Public Power and the Nation's Electric Cooperatives Have a Duty to Provide Reliable and Affordable Electric Service.

Public power and electric cooperatives have a duty to provide reliable and affordable electric service to their customers. That duty to serve their constituents comes from state statutes and common law that require the public power systems [5] and cooperatives [6] to provide an adequate, dependable and economical supply of electric power.[7]

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[5] *See, e.g.*, Ga. Code Ann. §46-3-125 (public power authority is charged with taking all "necessary or desirable action in order to provide or make available an adequate, dependable, and economical supply of electric power and energy and related services"), Miss. Code Ann. §77-5-703(c)(municipalities owning electric generation and/or distribution systems have obligation to provide most adequate, reliable and economical source of electric power), Neb. Rev. Stat. §70-1403 (public power has obligation to provide adequate, reliable and economical source of electric power).

[6] *See, e.g.*, Conn. Gen. Stat. Ann. §29-20-108 (municipal electric utilities can form cooperative public corporations to provide efficient, low cost and reliable electric power), La. Rev. Stat. Ann. §33-4545-2 (power authority authorized to cooperate with electric power cooperative associations to ensure an adequate, reliable and economical supply of electric power), Mass. Gen. Laws ch. 164,

B. Small Electric Generating Systems Often Rely On Just a Few Units and Must Be Able to Make Repairs to a Unit Without Taking that Unit Offline For an Extended Period of Time.

Many factors affect the amount of actual electric generation produced by steam from a boiler or "emissions unit" of a coal-fired electric generator – seasonal fluctuations in electric demand, the availability of other units in the system, the cost of one unit's generation relative to other units, the cost of electricity from other producers and even the annual rainfall, which affects the availability of electricity from hydroelectric power plants, which, in turn, affects the demand for electricity from fossil fuel electric generating units. A planned or forced[8] outage at one unit in the system will require immediate increased production at another unit within the system or region.

From time to time, public power and the electric cooperatives must take a unit offline to make a repair. Such a repair characteristically involves replacing a failed or worn component with a new or refurbished one. Typical examples of repair work to a coal-fired electric generating boiler are replacing steam tubing, water pumps and valves. These types of repairs allow the generating unit to maintain its full, legal, operational capabilities. EPA's position in the case before this Court is that many common (and often minor)

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§47C (municipal plant may form cooperative to provide efficient, low cost and reliable electric power).

[7] The cooperatives also have additional duties to serve originating from service agreements with consumers, corporate bylaws and articles of incorporation and, for those who acquire financing from the federal government, provisions in associated loan agreements.

[8] Forced outages are unanticipated and/or unplanned periods when a boiler is brought offline to perform necessary repairs.

repairs to units trigger NSR because they are physical changes that allow the facility to increase its hours of operation to levels that the unit was capable of achieving or had achieved in the past.

Although the larger electric generating systems have dozens of units that are subject to the CAA's NSR program, public power and rural electric cooperative power systems frequently have only a single commercial-sized coal-fired unit that serves thirty to fifty percent (or in some instances 100 percent) of the system's electric load. For example, 75 percent of all cooperative generators have a single coal unit that represents over twenty percent of all the electricity sold. Twenty-five percent of all cooperative generators have a single unit that represents thirty-three percent of all electricity sold. These small systems cannot take a unit offline a moment longer than necessary to make a repair without incurring potentially huge financial impacts if substitute power must be purchased on the wholesale market.

C. Requiring NSR Permitting For Repairs That Do Not Increase Achievable Hourly Emission Rates Would Present Small Utilities With a Hobson's Choice.

A forced outage in an electric generating system requires fast and deliberate action. The stakes are particularly high for smaller systems because, as noted above, a major portion of the system's ability to provide electric power to its consumers is no longer available. Unfortunately, under the position advocated by Petitioners, when a small system makes a repair that does not increase the unit's achievable hourly emissions rate but may allow the unit to increase utilization of existing capacity within permit limits, it will be faced with three equally untenable choices: (1) Obtain an NSR permit which takes on average 18 months, which would not be a feasible response to an immediate forced outage;

(2) Go through a CAA permitting process and obtain a "synthetic minor" permit[9] that effectively imposes permanent legal limits on the unit's operations, which process also cannot be completed expeditiously;[10] or (3) Conclude that no NSR permit is required (for example through a complicated and uncertain "actual-to-projected actual" emissions increase analysis) and risk enforcement action including massive civil liability to the utility and potential personal criminal liability to the responsible owner and/or operator if, after retrospective review, the regulatory agency believes that NSR was applicable.

Under EPA's enforcement interpretation, during any planned or forced outage, an operator must determine if a repair will trigger NSR applicability. In many cases, even with a planned outage, the actual physical repairs required are not ascertainable until the unit is actually offline and the internal parts exposed and examined by utility personnel. This NSR applicability determination can be extremely time-consuming, complex and uncertain, given varying interpretations posited by EPA over the years as well as in this case.

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[9] A CAA permitting process in which a utility obtains a synthetic minor permit is a process in which the unit's operator voluntarily imposes new lower legal limits on the unit's allowable emissions, which in most cases results in limiting the total number of hours the unit is allowed to operate in a year.

[10] A unit may be forced to accept a permit limit on its hours of operation because the approval and installation of Best Available Control Technology (BACT) emission controls is not a feasible response to a forced outage that needs immediate repair. Although usually shorter than the 18 or more months required to obtain an NSR BACT permit, depending on the jurisdiction, such a synthetic minor permit still requires a minimum 30 – 180 day public review period.

1. The NSR Permitting Process is Expensive, Time-consuming and Often Not Feasible.

The NSR review process consists of the preparation and submission of a permit application by the owner/operator of the unit, followed by an extensive review of the application by the state and/or federal permitting authority. The application includes an assessment of the air quality impact of the proposed major modification, an assessment of its potential effect on national parks or wilderness areas and an assessment of retrofitted pollution controls called the best available control technology (BACT) analysis. This review can take up to two years or more. Many states, in implementing Federal Clean Air Act requirements,[11] provide for a 30-day application completeness review, a 60-day agency technical review, a 30-day public comment period and a 30-day period for a public hearing. In some instances, the 30-day completeness review re-starts if application deficiencies are later identified. The BACT determination is one of the most complex portions of the NSR process involving a technical feasibility evaluation of alternative emissions control technologies, cost evaluations of each technology alternative and an assessment of the environmental and energy impacts of each alternative. Thus, the time period from submission of the application to approval of the permit is typically 18 to 22 months. *See, e.g.*, *Alaska Department of Environmental Conservation v. EPA*, 540 U.S. 461, 515 (2004)(process took 18 months). Even EPA in its report to President Bush on NSR admitted that the entire NSR permit process typically lasts between 7 to 22 months. *EPA New Source Review: Report to the President* (2002).

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[11] These requirements are implemented through CAA State Implementation Plans (SIPs).

This period does not include the time necessary to prepare the application (which can take six months or more) or to install any resulting controls, which could take years. Even a NSR non-applicability determination typically takes 18 months. If, in order to undertake common repair and replacement projects, a small utility is faced with the time it takes to prepare an NSR application, complete the permitting process, defend legal challenges to the permit and retrofit any required controls, that small utility may be unable to serve its customers and, accordingly, may have to forgo such projects.

The NSR permitting process is not only expensive[12] and time-consuming, but the resulting controls can add tens of millions of dollars in capital installation and annual operating costs to a system. Moreover, during NSR applicability determinations and permitting review, a public or cooperative utility may not be able to provide electricity to its consumers with existing generating capacity within its system, and thus may be forced to buy substitute power from others at uncertain and usually high wholesale market rates.

For all of these reasons, *amici curiae* are extremely concerned because repairs that only maintain a unit's full operational capabilities, but do not increase a unit's maximum hourly achievable emission rate would require NSR permitting under the position now advocated by EPA and Petitioners. It is difficult to believe that, by means of a technical amendment in 1977, Congress intended to expand the NSR program so radically and to create such a regulatory obstacle to the supply of reliable and affordable electricity to millions of households across the nation. Indeed, EPA's own interpretation and implementation of the program for nearly two decades never suggested that NSR could be triggered by common repairs that merely maintained a facility's operating

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[12] The air permitting application can cost as much as $500,000, including an assessment of BACT that can cost between $15,000 and $50,000.

capabilities without increasing the facility's maximum hourly emissions rate.

2. Obtaining a Synthetic Minor Permit is Not a Rational, Economically Feasible or Financially Prudent Alternative.

Petitioners suggest that one viable option to avoid the full NSR permitting process is to limit future potential annual emissions to significant emissions increase levels[13] above representative past emissions by obtaining a synthetic minor permit. This approach is not at all viable. Avoiding the lengthy NSR permitting process by artificially limiting unit utilization would be an enormously expensive and unwise alternative and is not contemplated by EPA's regulations. *See Wisconsin Elec. Power Co. v. Reilly*, 893 F.2d 901, 917 n.13 (7th Cir. 1990).

Generating units are utilized or "dispatched" in order of lowest to highest unit operating costs. Even "baseload" coal-fired utility units rarely operate at more than 80% of annual capacity factor.[14] Lesser utilized or "intermediate load" units operate at lower annual capacity factors but must be available to meet increasing electric demand during times of peak usage within the year or long-term outages of baseload units. In addition, many electric generating units are designed to meet both current and future customer electricity demands on utility systems and thus may not be operated at full operational capacity for a number of years until electricity demand grows. In such cases, these intermediate load units

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[13] The NSR definition of a significant increase for SO2, NO_x and volatile organic compounds (VOC) is 40 tons but other significance levels vary. 40 C.F.R. §52.21(b)(23).

[14] "Capacity factor" is the ratio of actual MWH generated in a year by the unit to the MWH that would be generated if the unit operated continuously at maximum output.

will be ramping up to baseload use. Likewise, some units may go for years with very minimal operation in areas of the county where hydro-electric power is the baseload economic choice and rainfall is adequate for years or even decades.

Under Petitioners' formulation, each time an operator makes a repair and accepts a synthetic minor NSR permit limit, it would have to restrict annual future usage based on its recent historic levels of operations to avoid the full NSR permitting process. Under the most recent NSR permitting process, typically a unit's future operation under a synthetic minor permit would be limited to an annual average emission based on the 24 consecutive months of highest operation over the previous five years. Thus, a small system with a unit under a synthetic minor permit limit loses its ability to use its needed and otherwise available and already permitted excess capability, and faces financially difficult choices in replacing that lost generation.

Taking a synthetic minor permit in response to a physical change in lieu of full NSR permitting may appear to be the most expedient option. This alternative, however, is typically very expensive. To demonstrate, NRECA aggregated for all cooperative coal-fired generating units the difference between their presently permitted electric generation (including annual emissions) and their generation (including annual emissions) if each unit were limited to its annual generation average of the highest 24 consecutive months within the five years from 2000 to 2004 using U.S. Department of Energy, Energy Information Administration (EIA) official data (Form 767). Summing this information for all cooperative units results in a combined generation loss of 18.28 percent. Stated differently, of the 23,089 MW of NECRA member cooperative coal-fired capacity legally available, the synthetic minor limitations would result in the

equivalent of over a 4,220 MW loss,[15] which equates to effectively eliminating over seven large commercial generating units, representing over $7 billion in replacement coal-fired generation.[16] This lost generation capacity would be enough to provide electricity to over 3.3 million residential homes.[17]

This loss of over 18 percent of cooperative generation capacity that would result if Petitioners' view of NSR were the law simply is not a viable option for small electric systems and cannot be justified to the customers of a public power system or to the members of a not-for-profit cooperative. The diminished unit availability would impact capital cost recovery, negatively affect financial credit ratings, and increase rates as additional generation facilities or the purchase of substitute power would be needed to make up for the lost generation capacities. Thus, synthetic minor permitting is not a rational, economically feasible or financially prudent alternative for the communities that own public power and for the consumers that own cooperative systems. This result certainly could not have been what Congress intended.

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[15] Technically, the loss is not one of capacity (MW), but one of generation output, best expressed in a megawatt-hour (MWh) metric. The MW capacity loss cited here is derived by dividing the MWh loss by 8,760, the total number of hours in a year.

[16] The replacement generation cost estimate of $1,700/KW (kilowatt) installed capacity is based on Department of Energy, Energy Information Administration (EIA) estimated "overnight cost" of new coal-fired generating adjusted to include a 10 percent contingency factor reflecting change orders in contracts during construction, a 4 percent real dollar increase in materials and labor, and a 7 percent cost of financing during five years of construction.

[17] This calculation is based on average sales to residential consumers based on EIA Electric Sales Revenue and Price, 2004 publication.

3. For Even a Short Period, the Cost of Replacement Power During NSR Permitting Could Be Crippling For Many Public Power and Rural Cooperative Systems.

The cost of replacement power purchased on the spot wholesale electricity market can be considerably more expensive than the power produced by a utility's own generating facilities because the price of substitute generation is market-based. The difference between the small utility's own generation cost and the price of substitute generation purchased on the wholesale market is especially exacerbated at times of peak demand such as during summer or winter because the wholesale market price of electricity is based on the cost of the last and most expensive generation, *i.e*., the last to dispatch in the region. One large APPA member in the West has seen the market price of wholesale electricity range from $50 to $400 per MWH during summer hours or other high load periods – a 700% price differential.

To illustrate the financial impact of the high cost of replacement power, for every twenty-four hour day a baseload commercially sized 600 MW unit is offline, the difference between the cost of replacement power and the cost of power generated by the unit can easily amount to $576,000 per day, over a 330% increase.[18] Taking a

[18] This result comes from standard engineering calculations assuming 80% annual capacity usage of the 600 MW unit and 8,760 hours in a year. Baseload generation costs of $15/Mwh, a realistic conservative average, and replacement power costs of $65/MWh were used. The replacement power cost is also a conservative estimate based on the average future prices derived from the five regional electricity trading hubs of PJM, Cinergy, Entergy, ERCOT, and Palo Verde over the twenty-month forward period beginning on August 2006. This information is provided by the energy brokers Amerax, Preban and TFS; and pricing reports in Platt's Megawatt Daily and NYMEX. Transmission costs, which can be very substantial, were excluded from this calculation.

synthetic minor permit for the unit assuming an 18% loss of capacity, a likely reduction discussed earlier, would cost the small utility over $70 million for the first 18 months for substitute power. This last figure, however, ignores the costs of supplying power after the initial 18-month period. To replace the 18% loss of capacity quickly, in 18 months, gas generation would likely be constructed or purchased, resulting in an additional cost of almost $69 million,[19] making the combined costs of supplying substitute generation while other generation is built plus the new generation total $139 million. Thus, in taking a commercial unit offline in a public power or cooperative system for even a few months while that system seeks an NSR permit, an NSR applicability determination or even a synthetic minor permit, the system would have to purchase replacement power at significantly higher prices and, ultimately, a significant rate increase could be necessary to cover the higher cost of purchased power and potentially building new power. Depending on the relative financial impact, credit ratings and potentially even the financial stability of these small systems could be very negatively affected.

Thus, during the 18-month NSR permitting process (or even in the synthetic minor permitting process), the small system would be forced to purchase replacement power in the wholesale market, which, depending on the prevailing rates, could spell severe economic problems for the system. Moreover, accepting an artificial cap on operations by means of a synthetic minor permit and operating well below

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[19] This calculation assumes combined cycle gas generation capital costs of $625/KW based on the EIA 2006 Annual Energy Outlook. The unit could be permitted in an expedited process as a Clean Air Act minor source and built in only 18 months. The calculation does not reflect the actual cost of power generation from this type of gas unit; it reflects only construction cost. Considering historically high natural gas prices, the overall cost of generating power from this unit operation would be considerably higher than the coal–fired generation it would replace.

capacity - - which systems might be forced to do - - would significantly impair the capital of the system.

Faced with these obstacles, under Petitioners' view, small generating systems would find it difficult, if not impossible, to meet their obligation to provide reliable and affordable electric service. Congress hardly could have intended to require small systems to undergo the lengthy and costly NSR permitting process every time they made a repair to a unit that did not increase its maximum achievable hourly emissions rate, and EPA could not have done so in its regulations without disclosing the extraordinary expansion of the NSR program it was contemplating and assessing the equally extraordinary economic impact of such an expansion. Yet, when it promulgated the 1980 NSR Rules, EPA's economic assessment showed no such expansion. *See* 45 Fed. Reg. 52,676, 52,729 (Aug. 7, 1980).

4. Requiring NSR Permitting For Repairs That Do Not Increase a Unit's Achievable Hourly Emissions Rate Would Subject Small Utilities to Constant NSR Permitting or Compromise of Capacity.

The problems generated by subjecting units to the NSR permitting process for repairs that do not increase the unit's maximum achievable hourly emissions rate are multiplied by the frequent shifts in generation loads or hours of operation of a unit within a small system. As set forth above, numerous planned and unplanned factors, including seasonal demand, forced outages and rainfall, affect the usage of a unit. If small utilities are required to go through the NSR review process for common repairs, such as those targeted by EPA in the NSR enforcement initiative, small utilities will be in a constant NSR permitting cycle.

Under EPA's enforcement interpretation, every repair or replacement of a component such as a tube assembly, pump

or valve - - which occurs frequently over the life of a generation unit - - would put the operator in the same predicament – undergo a lengthy NSR permitting process and install controls or limit capacity. If the utility chooses the more expedient option of a synthetic minor permit, it will find itself in a downward spiral, successively limiting its operations further and further below its permitted, full operational capabilities.

The dilemma faced by a small electric system contemplating repairs to a unit is exacerbated by the methodology for determining whether an annual emissions increase would occur if that methodology requires a "projection" of likely future utilization within permitted capacity. Such a projection is, at best, fraught with complexity, subjectivity and uncertainty.[20]

In the enforcement cases, EPA posited an outcome-determinative methodology that assumes that whenever a component that caused forced outages in the past is repaired, the repair will inexorably lead to "recovered" utilization and thus an increase in hours of operation and, therefore, emissions. This approach is in contrast to the NSPS maximum hourly emissions test, which is purely an engineering evaluation of the fuel burning (and therefore emitting) capacity of the unit in question.

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[20] Any emissions increase test that is based on projected utilization requires seer-like knowledge because it must be applied at the time of the proposed project and prior to post-project operation, when it is impossible to predict all future unit operational parameters that may affect emissions. For example, fuel characteristics such as inherent sulfur concentrations can vary unpredictably over time, resulting in annual unit emissions increases unrelated to any physical change; and seasonal generation demands on the unit due to weather or unit outages can force a greater operational burden on the unit than predicted. Additionally, many other unforeseeable factors can cause subtle unit emission increases unrelated to any physical change.

Thus, small utilities in particular will face significant uncertainty and expense because an NSR applicability determination implicates systems having only several units whose annual production and operating hours vary considerably as these units experience differing maintenance outage times and production rates to meet dispatch obligations on a year-to-year basis. The position advocated by EPA and Petitioners, which is not consistent with the requirement for a "modification" as determined under the New Source Performance Standards (NSPS), will make it impossible for small electric utilities to maintain their units as required or make desirable efficiency improvements. Operators will hesitate to take units offline to replace components to maintain unit performance because of the complicated analysis that would have to be performed to make an educated guess as to the risk that the repair will trigger NSR review - - a complicated analysis that is always subject to second-guessing because no one can accurately predict how the myriad of factors that affect the utilization of one unit within the system will change in the future.

Certainly, Congress could not have intended to subject small electric systems to such expense and uncertainty every time a unit undertakes the type of projects targeted in EPA's enforcement initiative. Yet, this will be precisely the result so long as the test required for NSR applicability is not keyed to a repair that actually increases a unit's maximum achievable hourly emissions rate.

5. The Potential Liability For Public Power and Cooperatives is Great.

If an operator errs in forgoing NSR permitting, the potential CAA liability is $32,500 per day per occurrence (i.e., per pollutant). If sulfur dioxide (SO_2) and nitrogen oxides (NO_x) triggered NSR review but the utility failed to

realize it for a year [21], the potential liability for noncompliance is $23,725,000 (365 x 2 x $32,500). 42 U.S.C. §7413(b). The utility could also face injunctive relief, including the cost of BACT, as well as potential personal liability.

Subjecting small utilities to the NSR applicability process for a mere increase in hours of operation after a common repair creates uncertainty over whether NSR permitting is required. Cooperatives and public power systems selecting any one of the Hobson's alternatives would face significant financial burdens because of loss of ability to utilize full generation capabilities of units that have required very significant capital investments, as well as additional costs to provide substitute generation to avoid abrogating their duty to their customers to provide reliable and affordable electric service.

II. USE OF THE NSPS DEFINITION OF "MODIFICATION" WILL NOT CIRCUMVENT CONGRESS' INTENT TO REQUIRE EMISSIONS REDUCTIONS NECESSARY TO MEET CAA HEALTH, WELFARE AND ENVIRONMENTAL GOALS.

Contrary to Petitioners' claims, rejection of EPA's enforcement interpretation will not circumvent Congress' intent to require emissions reductions necessary to meet CAA health, welfare and environmental goals. A significant portion of public power and cooperative coal-fired generation already meets NSPS requirements and/or has been through

[21] As discussed in *Alabama Power v. Costle*, 636 F.2d 323, 401 (D.C. Cir. 1979), a facility's "net" emissions across all the units at a facility over a five-year contemporaneous period are considered. *See also, New York v. EPA*, 413 F.3d 3 (D.C. Cir. 2005).

New Source Review, and is equipped with modern pollution controls.

Over 60 percent of public power's coal-fired generation already meets applicable NSPS requirements under the CAA. Likewise, over 50 percent of cooperative coal-fired generation already meets applicable NSPS requirements under the CAA. Additionally, 20 percent of all cooperative generation has gone through NSR.

Moreover, even those units that have not been through any form of new source review are well-regulated and will continue to be subject to other, increasingly stringent CAA programs that ensure that these facilities are well-controlled without interfering with their duty to serve. For example, due to subsequent CAA regulatory mandates effectively forcing pollution control retrofits on the remaining and older cooperative units, 90% percent of cooperative generation using high sulfur coal is equipped with flue gas desulfurization (FGD) units to control sulfur dioxide (SO_2) emissions, the primary pollutant associated with coal-fired generation.[22] In addition, virtually all cooperative generating capacity in the Eastern United States, equaling about 6,000 MW, is also retrofitted with state-of-the-art nitrogen oxides (NO_x) controls, Selective Catalytic Reduction (SCRs), because of EPA's NO_x SIP Call requirements promulgated in 1998[23], to control Eastern ozone. Almost all cooperative coal-fired generation is also equipped with low-NO_x burner technology regardless of where the units are located.

Thus, even though much of cooperative and public power coal-fired generation is newer and/or equipped with state-of-the-art pollution controls, electric cooperative generation and public power units would still be subject to the lengthy and costly NSR applicability process under EPA's NSR

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[22]This number includes one commercially sized unit where the FGD retrofit is ongoing.

[23] *See* 63 Fed. Reg. 57356 (Oct. 27, 1998).

enforcement interpretation, which would jeopardize their ability to provide reliable and affordable electric service.

CONCLUSION

Under Petitioners' view of NSR, the operator of a small electric utility who merely needs to replace a broken part would be forced to endure a lengthy NSR process and to navigate through a test that is so complex, confusing and fraught with subjectivity that it has gone through years of EPA iterations, interpretations and court battles. For the foregoing reasons, the judgment below should be affirmed.

Respectfully submitted,

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