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Modeling the Effects of Changes in New Source Review on National SO_2 and NO_x Emissions from Electricity-Generating Units

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RESOURCES FOR THE FUTURE

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Abstract

The Clean Air Act establishes New Source Review (NSR) programs that apply to the construction or modification of major stationary emissions sources. In 2002 and 2003, the U.S. Environmental Protection Agency revised its rules to narrow the applicability of NSR to facility renovations. Congress then mandated a National Research Council study of the effects of the rules. We used an electricity-sector model—the Integrated Planning Model (IPM)—to explore the possible effects of the equipment replacement provision (ERP), the principal NSR change that was to affect the power-generation industry. Although our analysis cannot predict effects on local emissions, assuming that the Clean Air Interstate Rule (CAIR) is implemented, we find that stringent enforcement of the previous NSR rules would likely lead to no or limited decreases in national emissions compared to policies such as ERP. Our results indicate that tighter emissions caps could achieve further decreases in national emissions more cost-effectively than NSR programs.

Key Words: New Source Review, NSR, CAIR, electricity, air pollution, emissions trading, Clean Air Act

JEL Classification Numbers: Q25, Q4, L94

Contents

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Introduction

The Clean Air Act includes a pair of programs that are together known as New Source Review (NSR). These are the Part D NSR and Prevention of Significant Deterioration programs. These programs require operators of new or modified large stationary sources to use advanced pollution-control technology. In addition, these sources must neither interfere with attaining national ambient air quality standards in “nonattainment” (dirty air) areas nor violate a set of increments designed to protect air quality from deterioration in “attainment” (clean air) areas.

While the applicability of NSR to new sources is relatively clear, controversy has arisen about which facility renovations constitute modifications. The Clean Air Act defines a “modification” as a physical or operational change that increases air pollution. In the late 1980s, EPA announced that a multifactor test, which includes consideration of the nature, extent, purpose, frequency, and cost of the work, would be applied to determine whether a renovation constitutes a modification or “routine maintenance” (*Wisconsin Electric Power v. Reilly* 1990). In addition, the agency has maintained that an alteration increases air pollution if it would raise annual emissions, even if the source’s maximum hourly emissions would not change.

In the late 1990s, EPA launched an enforcement initiative by filing legal action against some electricity-generating units (EGUs) that had renovated plant equipment, alleging that the renovations should have gone through the NSR permitting process (U.S. Department of Justice

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2002). The defendants have responded that these renovations (1) were exempt from NSR as routine maintenance and (2) did not increase emissions because each plant's maximum hourly emissions did not rise. Some of these enforcement actions are still pending; others have resulted in settlement agreements that include emissions restrictions at the system and/or boiler level as well as surrender of some emissions allowances so that emissions do not increase elsewhere (Ibid.).

In 2002 and 2003, EPA altered its rules to narrow NSR's coverage of modifications. For EGUs, the most important of these changes was the adoption in 2003 of the Equipment Replacement Provision (ERP). Under ERP, an equipment replacement costing less than 20 percent of the source's initial construction cost is generally defined as routine maintenance and exempted from NSR.

These rule changes, like EPA's enforcement initiative, incited controversy. In 2003 and 2004, Congress required EPA to contract with the National Academy of Sciences (NAS) for a study of the effects of the changes. This study has recently been published (NRC 2006). Some of us were members of the NAS committee, while another acted as an expert consultant.

The NAS committee used the Integrated Planning Model (IPM) to simulate the likely effects of ERP on national emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from EGUs (EPA 2005a). In this paper, we summarize the methods employed and the conclusions gleaned from these simulations and the related analysis.

We focused on EGUs, and in particular on coal-fired EGUs, for two reasons. First, coal-fired EGUs are important contributors of these pollutants, accounting for approximately 70 and 20 percent of national SO_2 and NO_x emissions in 2004, respectively (EPA 2005b). Second, the shares of total capacity of large coal-fired EGUs that lack flue-gas desulfurization (FGD) to control SO_2 and selective catalytic reduction (SCR) to reduce NO_x emissions are 62 and 63 percent, respectively (EPA 2004). Our modeling accounts for the impact of EPA's later decision to promulgate the Clean Air Interstate Rule (CAIR), which requires a phased reduction in emissions of these pollutants from EGUs in the East and the Midwest (EPA 2005c). CAIR, like its predecessors—the Title IV SO_2 program and the NO_x State Implementation Plan (SIP) Call—is a cap-and-trade program under which EGUs are given a fixed annual amount of emissions allowances that they can trade or bank for use or sale in the future. The goal of allowance trading is to reach emissions targets at least cost.

During the committee's study, ERP was invalidated by the D.C. Circuit Court of Appeals (*New York v. EPA* 2006). (EPA and some EGUs have requested that the U.S. Supreme Court review this decision.) Action also occurred on the issue of how to define whether emissions would increase. In *United States v. Duke Energy Corp.* (2005), the court ruled in favor of the EGU's position that an emissions increase has occurred only if the renovation has increased the maximum hourly emissions at the plant. (The Supreme Court is currently considering a challenge to this decision.) In response, EPA proposed to allow EGUs to use the hourly emissions approach to determine whether emissions will increase (EPA 2005d). Our model simulations of the ERP routine maintenance exemption are also applicable to the hourly emissions approach. The practical effect of both would be the same, since EGUs are very unlikely to trigger NSR under either method for determining the applicability of NSR. As a result, our analysis remains relevant until the fates of both ERP and the hourly emissions approach are decided.

Methods and Assumptions

Our modeling effort builds on the work done by EPA as part of its regulatory impact analysis (RIA) of ERP (EPA 2003). Our analysis examines a wider range of potential influence on generation-investment decisionmaking of the prerevision NSR regulations (we define "prevision" regulations as those that the ERP revisions were intended to modify). In addition, we analyzed potential interactions of NSR with CAIR; the RIA did not consider CAIR because it had not yet been proposed.

Description of IPM

For this modeling exercise, we used Version 2.1.9 of IPM, which was released in 2004 (EPA 2005a). IPM, a deterministic model of the electricity sector, uses linear programming to find the least-cost pattern of EGU dispatch and generating-capacity investment and retirement to meet peak demands and regional reserve requirements. The least-cost approach is equivalent to the simulation of a perfectly competitive market in which all market participants have perfect information and demand is perfectly inelastic. Other simulation models, which are used to analyze the effect of regulatory changes on the power sector, have also adopted this approach (Energy Modeling Forum 2001).

IPM divides the continental U.S. electricity sector into 26 regions and allows for interregional power trading within the bounds of interregional transmission capacity, subject to transmission losses. Price-responsive fuel supplies are modeled using stepped supply curves for natural gas and coal. The model incorporates regulatory restrictions on emissions of air pollutants from EGUs. In the case of a cap-and-trade program such as CAIR, IPM finds the lowest-cost approach to comply with the program.

The model requires assumptions about the representation of decisionmaking in the industry, values of important parameters, and relevant environmental policies and enforcement actions. Other national power-sector models share most of these assumptions and the resulting limitations. EPA has subjected IPM's input assumptions to extensive stakeholder and peer review and has conducted validation tests of IPM short-term outputs. EPA studies indicate that IPM can reasonably approximate electricity-generating sector operations on a regional scale (as reported in NRC 2006).

We ask the reader to keep in mind the adage that "all models are wrong, but some are useful." Although models necessarily simplify reality, they can yield useful insights about the general response of a system to regulatory changes. Given the extensive reliance that EPA and others have placed on IPM-type models and their demonstrated usefulness in projecting the qualitative effects of previous policy changes, the committee concluded that IPM is the only practical tool available at this time to explore the possible effects of the NSR rule changes on national emissions.

Several structural assumptions have important implications for the results of this analysis. First, computational limitations require that existing generating capacity be aggregated into a limited number of model plants. Even with this aggregation, the number of decision variables in IPM is typically on the order of one million or more. Aggregation means that the model does not usually provide direct results for generation or emissions at the plant or local level. Similarly, given the aggregation of generators over space, the model lacks intraregional constraints and institutional barriers such as those associated with vertically integrated electricity firms. In general, omitting such constraints means that electricity cost estimates are biased downward.

Second, the model does not explicitly represent maintenance or life-extension options of the sort that could trigger NSR, nor their costs or effects on unit performance. As a result, it is difficult to directly analyze the effects of NSR rule changes on these types of investments. Instead, we must do it through a scenario-based approach.

Third, the model assumes that all EGUs have perfect foresight with respect to changes in electricity prices, fuel and other costs, and environmental policies. This means that the model is unable to reflect the impact of risk aversion or imperfect information on EGU decisions. In addition, the model typically assumes that parameters are realized at their estimated means. Sensitivity analysis can assess the effect of input uncertainty, but time and budgetary constraints limited the number of alternative scenarios that we could analyze.

Fourth, as explained in the next subsection, we simulated the effect of NSR regulations that the ERP revisions were intended to modify (the prerevision NSR). To simulate their effect, we defined a constraint that forces a given fraction of existing coal-fired capacity either to retire or to retrofit NSR-compliant generation or emissions-control technology. IPM then chooses the least-cost set of plants for such retirements or retrofits, recognizing the value of the resulting emissions reductions under emissions trading. We used this least-cost assumption for modeling convenience. Simulating other ways of choosing EGUs for possible retrofit would have been desirable because EPA or Department of Justice enforcement of prerevision NSR rules would not necessarily be based on a least-cost criterion. An example might be a selection criterion based on size or amount of emissions from generation units. Such a criterion, however, would likely result in a pattern similar to the lowest-cost assumption because retrofits would probably be the least costly for the larger units.

Definition of Scenarios

The IPM scenarios are specified on three dimensions. One consists of different versions of EPA policy, which governs the breadth of the routine maintenance exemption from NSR along with varying assumptions about the exemption’s effects on EGU decisions. A second dimension represents assumptions about whether CAIR and other recent air-pollution regulations will be in place. The third dimension consists of alternative scenarios about investment costs for renewable and advanced electricity-production technologies. The IPM runs are described in the following subsections and summarized in Table 1.

Dimension 1: Strictness of NSR Policy

First, we simplified the NSR policies into two basic alternatives—the enforcement of the prerevision NSR multifactor approach and ERP (the “base case”). For the prerevision NSR rules, we defined two general variants: (1) “avoid,” in which generators are generally able to avoid triggering NSR but at the cost of worsening performance (as assumed by EPA in its RIA for ERP [EPA 2002]); and (2) “R/R/R,” where a given quantity of coal-fired capacity must either retrofit pollution controls, repower with NSR-compliant generation technology, or retire. Economic, policy, and legal uncertainties are too great to determine which variant is most likely to be correct, so we adopted this scenario approach to explore and bound the consequences of alternative assumptions.

We used the EPA RIA results to represent the avoid variant of the prerevision rules. This variant anticipates that prerevision NSR would cause generator owners to avoid undergoing NSR by deferring maintenance. The assumed consequence of this anticipated behavior is a steady 0.1 percent per year deterioration in efficiency and capacity. This deterioration yielded higher generation costs but essentially the same temporal pattern of NO_x and SO_2 emissions as the ERP scenario. Emissions caps would therefore determine the total emissions in the avoid variant. Consequently, if the prerevision NSR rule results in all generators avoiding NSR, the national NO_x and SO_2 emissions differences between the prerevision rule and the proposed ERP would be minor.

The R/R/R variant posits that enforcement of the prerevision NSR rules would cause some capacity without FGD or SCR to install these controls or retire. Subvariants assume different lower bounds on the amount of capacity (defined as a fraction of 2004 capacity) that must retrofit, repower, or retire in each year. These restrictions become increasingly expensive to achieve as the share of capacity yet to comply with the R/R/R requirement diminishes over time. The low R/R/R variant assumes that capacity equivalent to 2 percent of the 188.5 gigawatts (GW) of coal-fired capacity without FGD as of 2004 (190.4 GW of capacity without SCR) is subject to R/R/R in each year from 2007 through 2020. As a result, a minimum of 2 percent of coal-fired capacity has either been retrofitted, repowered, or retired by 2008; 4 percent by 2009; and so forth, reaching a lower bound of 26 percent in 2020 and every year thereafter. The two other variants assume 5 and 7.5 percent retrofit rates per year, respectively. The 5 percent/year scenario (the middle variant) implies that at least 65 percent would be subject to R/R/R by 2020; the 7.5 percent/year scenario (the high variant) reaches 97.5 percent by 2020. Thus, by 2020, the high R/R/R scenario results in 50 percent more forced retrofits than the middle R/R/R variant. The rate of retrofit adoption suggested by the high variant is unlikely because some fraction of uncontrolled generation is probable (to avoid NSR by deferring maintenance). Nevertheless, we did analyze the high scenario, treating it as a bounding case.

Some might even find the rate of NSR applicability under the lower R/R/R scenarios implausibly high. EPA has recently been paying attention to alleged violators, though, which may influence EGU owners to conclude more often that NSR is applicable to a particular maintenance project. Expectations about the probability of enforcement have likely risen, as well as expectations of the size of the penalties that sources may face for noncompliance. (Violations at a single plant have led to penalties requiring pollution control retrofits at numerous other plants.) Keohane et al. (2006) show that plants responded to the possibility of being subject to enforcement action by lowering their 1999 SO_2 emissions rates to avoid regulatory scrutiny. Admittedly, this effect may be ephemeral. In the long run, sources may simply avoid the types of investments that attracted EPA's attention. If this hypothesis holds true, net NSR-induced retrofits may not increase at all. Bushnell and Wolfram (2006) present evidence supporting this hypothesis, noting that plants in states with tighter regulations and those more likely to be subject to NSR have avoided making large maintenance investments. These investigators, however, find that reduced capital investment has not had a negative impact on the fuel efficiency of these plants.

The three R/R/R scenarios of EPA's prerevision NSR approach represent different assumptions about the pace and effectiveness of enforcement. When estimating the costs of implementing the specified fraction of R/R/R, IPM yields an estimated lower bound on cost because the model chooses the lowest-cost method of meeting the constraint. As we noted previously, EPA may not choose EGUs for enforcement actions in this way, so actual costs of complying with NSR might be higher. Another important assumption concerns the number of allowances that are surrendered as part of enforcement actions. In several NSR settlements, electric generators have surrendered allowances as a penalty for noncompliance. Our R/R/R scenarios assume no further allowance surrenders. Additional surrenders might be possible under the prerevision NSR rule; however, because it is uncertain how many may occur, we did not model them.

In contrast to these prerevision scenarios, ERP is assumed to be embodied in the EPA IPM base cases (EPA 2005e). Essentially, the assumption is that ERP has such a negligible or unidentifiable effect that the IPM ignores the incentives it generates. The ERP base-case runs are compared to the R/R/R runs to assess possible emissions, cost, and technology effects of ERP under the assumption that retaining the prerevision NSR approach would force a substantial amount of coal capacity without FGD to face the R/R/R decision. We did not compare the base cases to the avoid variants because the IPM runs from the 2002 ERP RIA are based on an earlier set of economic and technological assumptions (EPA 2002).

Dimension 2: CAIR and Other Regulations

To consider how the R/R/R characterizations of NSR may interact with different caps on NO_x and SO_2 emissions, we identified two alternative regulatory backdrops. Under one alternative, the "without-CAIR" case, the only federal regulations in place are the 1990 Title IV acid rain control program and the 1998 NO_x SIP Call. The Title IV program consists of a national cap-and-trade program for SO_2 from large coal-fired power plants. (Title IV also contains a program that reduced the allowable NO_x emissions rate of these plants, but it is of little consequence to our analysis.) Annual allocations under the SO_2 cap-and-trade program were essentially constant from 1995 until 2000, when they fell as the program went into its second phase. These allocations will essentially be constant in the future, but annual emissions are expected to decline over time as allowances banked in the early part of the program are drawn down at a declining rate. The NO_x SIP Call, which became fully effective in 2005, is a cap-and-trade program affecting summertime (May through September) emissions in 19 eastern states.

The other regulatory baseline alternative, referred to here as the "with-CAIR" case, assumes that CAIR is implemented along with the Clean Air Mercury Rule (CAMR) and the best available retrofit technology (BART; or Clean Air Visibility Rule [CAVR]). CAMR caps nationwide mercury emissions from coal-fired boilers and the BART rule (or CAVR) reduces emissions that threaten visibility around national parks and wilderness areas (EPA 2005f, 2005g). Note that CAIR, which begins in 2010 and is fully implemented by 2015, does not replace the Title IV regulations (although in addition to applying annual caps it does replace the SIP Call with a similar seasonal program). In fact, Title IV allowances are used to implement the SO_2 control element of CAIR. Sources affected by CAIR must hold 2.86 Title IV allowances per ton of SO_2. Therefore, national SO_2 emissions are still subject to a cap, although a subset of the affected sources must hold more allowances per unit of emissions.

The with-CAIR baseline analysis from EPA (2005e) serves as the ERP simulation under the CAIR rule. We compared this analysis to the R/R/R with-CAIR scenarios. We did not compare the avoid-prerevision variant with the base ERP/CAIR case. Such a comparison is unnecessary because CAIR makes it highly unlikely that emissions would increase if facilities were to avoid NSR. By making the aggregate emissions caps stricter in the East and the Midwest and, in the case of NO_x, broader in geographic and temporal scope, CAIR raises the cost of maintenance deferrals or other measures that would increase emissions at individual facilities.

Dimension 3: Alternative Economic, Market, and Technology Scenarios

We conducted two sensitivity analyses. In the first, we considered whether alternative plausible assumptions about the cost of new-generation technology might result in more coal-capacity retirement. We focused on the high R/R/R case under the CAIR scenario in those analyses where we thought the pattern of retrofit and retirement would be most sensitive to these changes. The first additional run lowered investment costs for renewable-energy plants, including wind, solar, landfill gas, biomass, and geothermal, by 20 percent. Further, it lowered investment costs for new integrated gasification combined cycle (IGCC) plants, generating cost reductions of 15 percent in 2010, 20 percent in 2015, and 25 percent in 2020 and 2026. In addition, the capital cost of repowering coal steam to IGCC was lowered by 20 percent.

In the second sensitivity analysis, we took the annual national NO_x and SO_2 emissions results achieved in the high R/R/R scenario and calculated the lowest-cost means of achieving the associated emissions reductions in each simulation year. This approach, which simulates using a policy of caps with allowance banking to achieve the same national emissions levels, indicates how cost-effective the prerevision NSR might be for accomplishing incremental reductions in national emissions (compared to a policy of tightening emissions caps further).

Results

Emissions-Reduction Strategies

We first review the differences in generation and investment patterns among the solutions. The IPM runs show that coal-fired EGUs nearly always respond to an assumed mandate to retrofit, repower, or retire by retrofitting emissions controls. Imposition of even the high (7.5 percent) R/R/R scenario results in less than 2 percent of the uncontrolled capacity repowering or retiring. Further, a comparison across the different scenarios shows relatively little difference in the national share of coal-fired generation. Coal-fired EGUs, however, use coals with different sulfur content in response to the varying strictness of the R/R/R scenarios. Essentially we are assuming that once a source undergoes NSR, it is under no obligation to also use coal with lower sulfur content or whatever coal type it was using before retrofitting. As a consequence, in 2007 without CAIR, coal production in the Appalachian and Interior regions of the United States, where coal has higher sulfur content, is about 9 percent greater in the high (7.5 percent) R/R/R scenario compared to the ERP case. In 2020 this difference is 39 percent. With CAIR, these differences in Appalachian and Interior coal production between the ERP base case and the high R/R/R scenario are only 2 percent in 2007 and 23 percent in 2020. With each regulatory baseline and in each simulation year, there is a roughly commensurate reduction in the production of western coals. (Note that such incentives are not associated with NO_x emissions control. IPM assumes, as is generally the case, that NO_x emissions rates are relatively unaffected by the type of coal consumed.)

Figure 1 shows the trends in the cumulative amount of capacity with FGD after 2007 for the R/R/R and ERP solutions. Absent CAIR, the amount of capacity with FGD increases linearly in each scenario. But with CAIR, the R/R/R constraints bind (i.e., actually increase FGD capacity relative to the base-case ERP) only in the later years, and then only in the middle and high R/R/R scenarios. In earlier years, and for all years with the low R/R/R scenario, high allowance prices under the tight CAIR emissions caps motivate more retrofits than the R/R/R constraints require.

Temporal Distributions

The temporal pattern of emissions of each prerevision R/R/R scenario differs between SO_2 and NO_x. Figures 2 and 3 present the total U.S. emissions levels in tons for those scenarios, as well as for the base case (which we interpret as representing implementation of either ERP or the hourly emissions test proposed by EPA). For reference, the figures also show the historical SO_2 and NO_x emissions by U.S. EGUs.

All R/R/R scenarios yield some emissions decreases compared to ERP, assuming that only Title IV and the NO_x SIP Call caps are in place (Figure 2). In the most extreme case (the high R/R/R scenario), NO_x emissions in 2020 are 54 percent of the emissions in the base case, because there is no broad cap-and-trade program for reducing national NO_x emissions. The temporal emissions pattern for SO_2 shows some changes for the middle R/R/R scenario, but the anticipated 2 percent emissions decrease in 2010 is more than matched by a predicted increase of 10 percent in 2007, with only negligible changes in total emissions from 2007 to 2020. However, if we expect that damages realized in the near future are valued more than those incurred in the distant future, and that marginal damages increase with emissions, this temporal shift in emissions likely raises realized damages (although we ignore the effect of any spatial changes in emissions). Only the high R/R/R scenario causes SO_2 emissions to fall significantly below Title IV allocations, and then only in 2020. By that year, nearly all coal capacity has FGD, and SO_2 emissions fall to 41 percent of the base-case 2020 levels. If CAIR is not implemented, then, prerevision NSR rules could significantly affect national emissions compared to the ERP or the proposed hourly emissions approach.

We turn now to solutions that assume the implementation of the tighter caps for SO_2 and NO_x under CAIR (Figure 3). The low and middle R/R/R scenarios indicate that, except for NO_x in the year 2020, the prerevision NSR rules would not pull national emissions below the CAIR caps. NO_x from CAIR-affected sources falls 10 percent below the cap in 2020 in the middle R/R/R case. The total decrease in NO_x relative to the CAIR ERP base case, though, is considerably smaller than if only Title IV and the NO_x SIP Call were in place (Figure 2).

In contrast, the high R/R/R scenario under CAIR illustrates some surprising interactions among the prerevision rules and the emissions caps. In particular, the SO_2 decrease in 2015 and 2020 in the high scenario is matched almost ton for ton by increases in 2007 and 2010. The 2007 and 2010 emissions are higher than in the ERP with-CAIR scenario because of the availability of banked SO_2 allowances from Title IV. As the amount of installed FGD increases in later years in response to the high R/R/R policy, it becomes easier to comply with the constraint on national emissions imposed by CAIR. Consequently, the price of emissions allowances falls, there is less incentive for sources to hold allowances for later use, and emissions rise in the earlier years. As a result, the main effect of the high R/R/R scenario is to redistribute SO_2 emissions over the period from 2007 to 2020 relative to the base case, but not to reduce the total. If marginal health and other damages are increasing with emissions and any positive discount rate is used to evaluate damages, this redistribution is undesirable. It is possible, however, that emissions in 2025 and later years will be lower under the high R/R/R scenario than under the ERP base case if emissions caps are not tightened further after 2020.

The pattern of NO_x emissions in the high R/R/R scenario under CAIR does not present the intertemporal shift exhibited with SO_2. Instead, no emissions increases are seen in earlier years relative to the base case, and emissions are lower by 7 percent in 2015 and 34 percent in 2020. Thus, in the case where the prerevision NSR rule is assumed to compel nearly every coal-fired generator to engage in R/R/R by 2020, the prerevision NSR rules have NO_x emissions-reduction benefits relative to ERP even under CAIR. Those benefits, though, largely or completely disappear under the more-realistic low or middle scenarios.

The different temporal patterns of national NO_x and SO_2 emissions are partly the result of the greater flexibility that generators have to alter SO_2 emissions. These emissions can be adjusted by switching to coal with a different sulfur content as well as by installing postcombustion controls and changing generation dispatch so that cleaner facilities are operated more often. Once FGD is installed, a coal-fired generator that previously burned low-sulfur coal may switch to less- expensive, higher-sulfur coal to keep its costs down, thereby diminishing the ultimate effect of the retrofit on total emissions of SO_2 from the facility. In contrast, options for reducing NO_x emissions are typically limited to pollution-control retrofitting or curtailment of operations.

Spatial Distributions

Because CAIR affects only eastern and midwestern states, we might expect that R/R/R constraints would affect emissions from sources within the CAIR region differently than sources elsewhere, relative to the ERP base case. We focus on the high R/R/R scenario because it is the only R/R/R case that yields noticeably different annual national emissions compared to ERP. The results indicate that most NO_x emissions reductions under the high R/R/R scenario (relative to the ERP with CAIR) occur at non-CAIR-affected units, although after 2015, emissions from CAIR-affected units are reduced as well. Yet SO_2 emissions reductions in 2015 and 2020 under the high scenario (relative to the CAIR base case) occur primarily at CAIR-affected plants.

This emissions pattern is explained by the interplay of emissions caps and the extent of equipment retrofits at CAIR versus non-CAIR plants. Once the NO_x cap is nonbinding and NO_x allowance prices fall to zero, which happens around 2010 in the high R/R/R scenario, EGUs see no financial benefit from freeing up allowances by installing R/R/R-mandated controls in the CAIR region. At the same time, low-cost NO_x controls will already have been installed in the CAIR region when the cap was binding before 2010. We might expect, then, that under the high R/R/R scenario, retrofits in later years would occur in western (non-CAIR) areas where low-cost retrofits were still available. This is indeed the case. The share of capacity with SCR retrofits at non-CAIR-affected coal-fired EGUs is 7 percent in 2015 and 2020 with ERP. (Non-CAIR-affected units comprise about 19 percent of total coal-fired capacity in the contiguous United States.) But under the high R/R/R scenario, 40 percent of non-CAIR-affected coal capacity would have SCR retrofits in 2015, rising to 92 percent by 2020.

In contrast, the existing share of non-CAIR-affected capacity that has FGD is already high under the ERP case, assuming CAIR is implemented. In part this is because, although these plants are outside the CAIR region, they are still part of the Title IV SO_2 cap-and-trade program. The share of non-CAIR sources with FGD is 59, 63, and 85 percent in 2007, 2010, and 2015, respectively, under both the ERP and high R/R/R scenarios. A noticeable difference is seen only in 2020, when 88 percent of the non-CAIR capacity has FGD under the ERP and 96 percent has FGD under the high R/R/R scenario. This difference is slight, however, relative to CAIR-affected coal-fired EGUs, where 64 percent have FGD in 2020 with ERP while 93 percent have FGD with the high R/R/R scenario. The benefit of installing FGD in the CAIR region when forced by the high R/R/R scenario is that sources can use less-expensive high-sulfur coal. EGUs thus benefit financially from installing controls in the CAIR region as long as the SO_2 cap remains binding and allowances have value.

Sensitivity Analyses of New-Generation Technology Costs

As described earlier, we ran the high R/R/R scenario under CAIR using assumptions of lower investment costs for renewables and IGCC. The results show almost no difference in emissions, the generation mix, and emissions controls through 2020. Renewable generation capacity goes up by about 15 percent in 2020 compared to the original high R/R/R analysis. However, because this increase is from a small base (14 GW, less than 5 percent of the amount of coal capacity), it has a negligible effect on emissions. Similarly, even though new IGCC capacity more than doubles compared to the original high R/R/R analysis (to 12.2 GW by 2020), this is only 3 percent of total coal capacity.

Efficiency of Different Regulatory Techniques for Reducing Emissions

Comparing the high R/R/R scenarios with and without CAIR provides one indication of the effectiveness of economic incentives to lower SO_2 and NO_x emissions by taking advantage of all abatement strategies. Those two solutions have similar amounts of FGD retrofits in every year (Figure 3). But CAIR SO_2 emissions are nearly 30 percent less than the Title IV/NO_x SIP Call results in 2007 and 2010 and 46 percent less in 2015. The story is similar for NO_x emissions. These solutions have similar levels of control retrofits but different emissions levels for two reasons. First, the tighter restrictions on NO_x and SO_2 emissions in the CAIR cases motivate installation of the control retrofits at locations where they are more cost-effective in reducing emissions. On the other hand, our R/R/R scenarios tend to lead to the installation of controls in order of lowest to highest cost per megawatt of capacity, regardless of cost-effectiveness.

Second, CAIR's tighter restrictions motivate fuel-switching and emissions-dispatch strategies for reducing emissions at generating units that are not retrofitted with controls. In contrast, strategies such as the emissions-control retrofits required by NSR provide no incentives to adopt such operating strategies for reducing emissions.

We now consider the cost-effectiveness in dollars per ton for each R/R/R case against the ERP base case for both the Title IV/NO_x SIP Call and the CAIR scenarios. In this context, we define "cost-effectiveness" as the increase in the present value of the total cost of electricity production divided by the reduction in emissions. For simplicity, NO_x and SO_2 reductions are weighted equally. Costs and emissions from 2007 through 2020 are considered; values for years between the simulation years (2007, 2010, 2015, and 2020) are obtained by linear interpolation. We calculate two cost-effectiveness measures for each R/R/R case: one based on discounting emissions reductions and the other considering a simple sum of reductions over those years. Discounting emissions reductions is equivalent to calculating a levelized cost per ton of emissions reductions, and, in essence, treats the benefits of emissions reductions as equivalent to the costs of achieving these reductions in the future. We assume a 5 percent per year discount rate.

The runs show that when the NSR R/R/R constraint yields emissions reductions compared to the ERP without CAIR, their cost is between $850 and $5,900 per ton (1999$).

With the CAIR emissions constraints, the incremental cost of any further emissions reductions associated with the prerevision rule would be between $2,900 and $53,000 per ton. When emissions (undiscounted or discounted) increase under the R/R/R scenarios (e.g., the high R/R/R scenario with CAIR), the cost-effectiveness is necessarily negative—both emissions and costs are higher. The cost per ton of reductions is highest in the scenarios where emissions are reduced only slightly (i.e., the middle R/R/R scenarios). For example, relative to the CAIR base case, the discounted total emissions reductions from the middle R/R/R scenario are 18,000 tons (+340,000 tons of SO_2 and –358,000 tons of NO_x; undiscounted figures are +383,000 and –707,000 tons) and the additional cost is $950 million, yielding an average reduction cost of $53,000 per ton. In contrast, under the high R/R/R case, the discounted reduction is about 700,000 tons (+789,000 tons of SO_2 and –1,480,000 tons of NO_x; undiscounted figures are +239,000 and –2,765,000 tons) with an incremental cost of $9.2 billion for an average reduction cost of $13,000 per ton.

We would not expect such a fluctuating pattern of cost-effectiveness, with average emissions-reduction costs rising and then falling as emissions decline, if we were instead tightening a national emissions cap. As an emissions cap is tightened, we would expect the average cost of emissions reductions to always rise. As we have modeled it, however, the R/R/R program does not target emissions, but rather the *amount* of capacity that is retrofitted or retired. With such a policy, there is no assurance that the boilers that are cheapest to retrofit with pollution controls are necessarily those that achieve the most cost-effective emissions reductions. Further, as we described previously, once emissions caps are binding in an intertemporal sense, forcing additional SCR and FGD retrofits results in substitution away from other abatement techniques such as fuel switching. This incongruence between the incentives of the NSR policy and the goal of reducing emissions in the presence of emissions caps is most pronounced in the middle R/R/R scenarios.

These costs per ton of reduction are large compared with the costs of achieving emissions reductions by using a cap alone. A first indication of this is the cost of the CAIR-induced reductions relative to the Title IV/NO_x SIP Call under the ERP, which is $470 per ton (undiscounted) to $730 per ton (discounted). CAIR's incremental cost per ton is smaller by an order of magnitude or more than the incremental cost of emissions reduction achieved by the NSR R/R/R scenarios we reported on earlier. A more relevant comparison would be the potential for cost savings if, rather than achieving further emissions reductions via prerevision NSR, they are achieved via tighter national caps on emissions. To make this comparison, we conducted a sensitivity analysis where the IPM was run without R/R/R limits but with constraints forcing national SO_2 and NO_x emissions in each of the solution years to be no more than the levels achieved in the with-CAIR high R/R/R scenario.

We found that the additional pollution-control costs under the hypothetical national emissions caps were less than the costs under the high R/R/R scenario. The cost-effectiveness of the incremental emissions reductions achieved by these national caps beyond the CAIR ERP base case is $960 per ton (undiscounted) and $2,600 per ton (discounted). Those costs are one-third and one-fifth, respectively, of the cost of the same emissions reductions obtained by relying on the prerevision NSR rule, assuming the high R/R/R scenario ($3,100 and $13,000, respectively). This shows that the prerevision NSR rule is not a cost-effective way to achieve national emissions reductions. Using emissions caps to obtain the reductions achieved by the high R/R/R scenario results in fewer FGD and SCR retrofits (30 percent fewer in 2020); more consumption of western low-sulfur coal (14 percent more in 2020) and natural gas; and more selective noncatalytic reduction (SNCR) controls. (SNCR is a postcombustion control technology for NO_x that costs less than SCR but reduces emissions by about a third as much.) The prevision NSR approach gives sources less flexibility by interfering with emissions trading. Sources are thus deprived of the opportunity to arrive at lowest-cost solutions (see NRC 2004) so that it becomes more expensive to achieve the same national emissions reductions.

Conclusions

We caution that economic and legal uncertainties are too great to determine precisely how generator decisions to retrofit, repower, or retire are affected under the prerevision NSR rules or under the 2003 ERP proposal (or its functional equivalent, the hourly emissions averaging proposal). Given these uncertainties, we have adopted a scenario approach to explore and provide bounds on the likely consequences of different potential stringencies of NSR applicability. We show that sectoral simulation models such as IPM can be helpful for projecting industry-wide responses to the ERP and analyzing its effects on national emissions; however, such models are insufficiently detailed to assess effects on local emissions or air quality.

The EPA RIA (2004) assumed that, under the prerevision NSR rules, generation owners would choose to avoid NSR by deferring maintenance. We examined a broader array of scenarios concerning the possible reaction of the power industry to the prerevision NSR rules. Depending on the stringency of emissions caps, our analysis shows that changing assumptions about industry response can alter the conclusions reached by comparing the prerevision NSR rules with ERP. Also, the potential effects of adopting ERP on national power sector emissions differ between SO_2 and NO_x and depend on whether CAIR is in place.

Unless controls become extensive enough to reduce emissions for both NO_x and SO_2 below their respective caps, the main effects of a prerevision NSR policy—which would force more facility retrofits or retirements—would be to increase power costs and spatially redistribute emissions. With the caps binding, emissions reductions associated with NSR at one facility free up allowances that permit emissions elsewhere to increase. Health effects could plausibly increase or decrease, depending on where and when emissions changes occur.

In contrast, if a prerevision NSR policy would change generator decisions sufficiently to pull emissions below the caps, the prerevision rules would yield lower emissions than ERP. But the cost of such incremental reductions with prerevision NSR is several times as high as the cost of achieving the same reductions by tighter cap-and-trade policies. We note, though, that NSR has additional goals, such as preventing local increases in air pollution, and that the IPM does not address those other goals.

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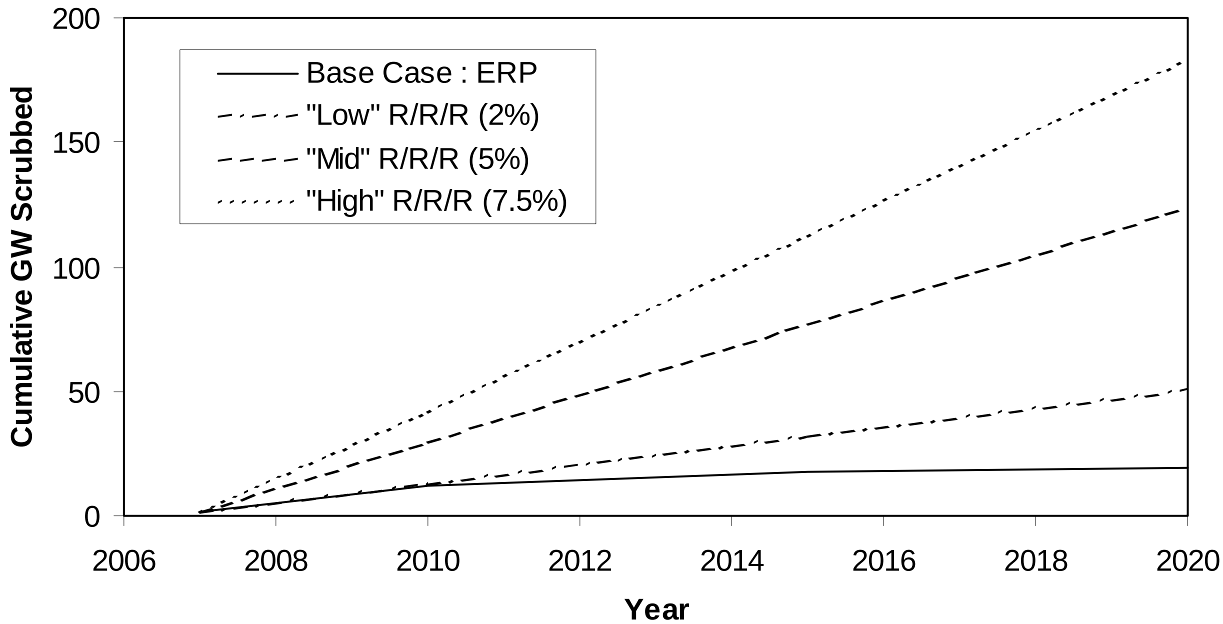
Figures and Tables

Figure 1. Cumulative FGD Retrofits for ERP and Prerevision R/R/R NSR Scenarios

(a) Title IV/NO_x SIP Call



(b) CAIR

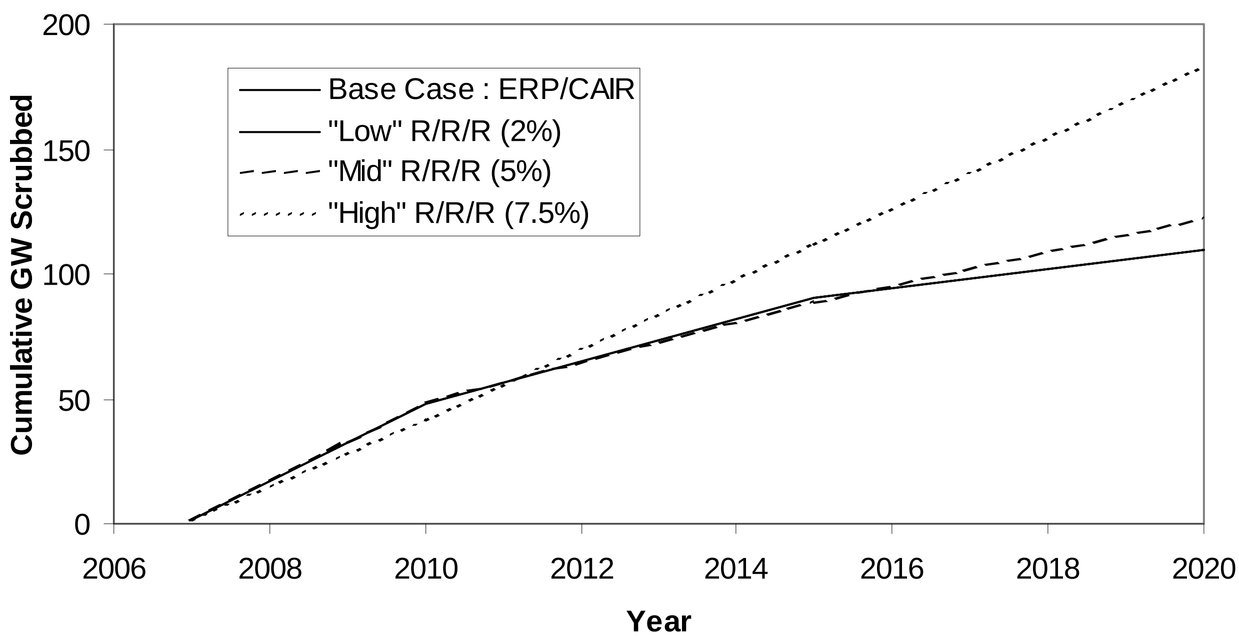


Figure 2. National SO_2 and NO_x Emissions, R/R/R and ERP (Base-Case) Scenarios without CAIR (Title IV/NO_x SIP Call)

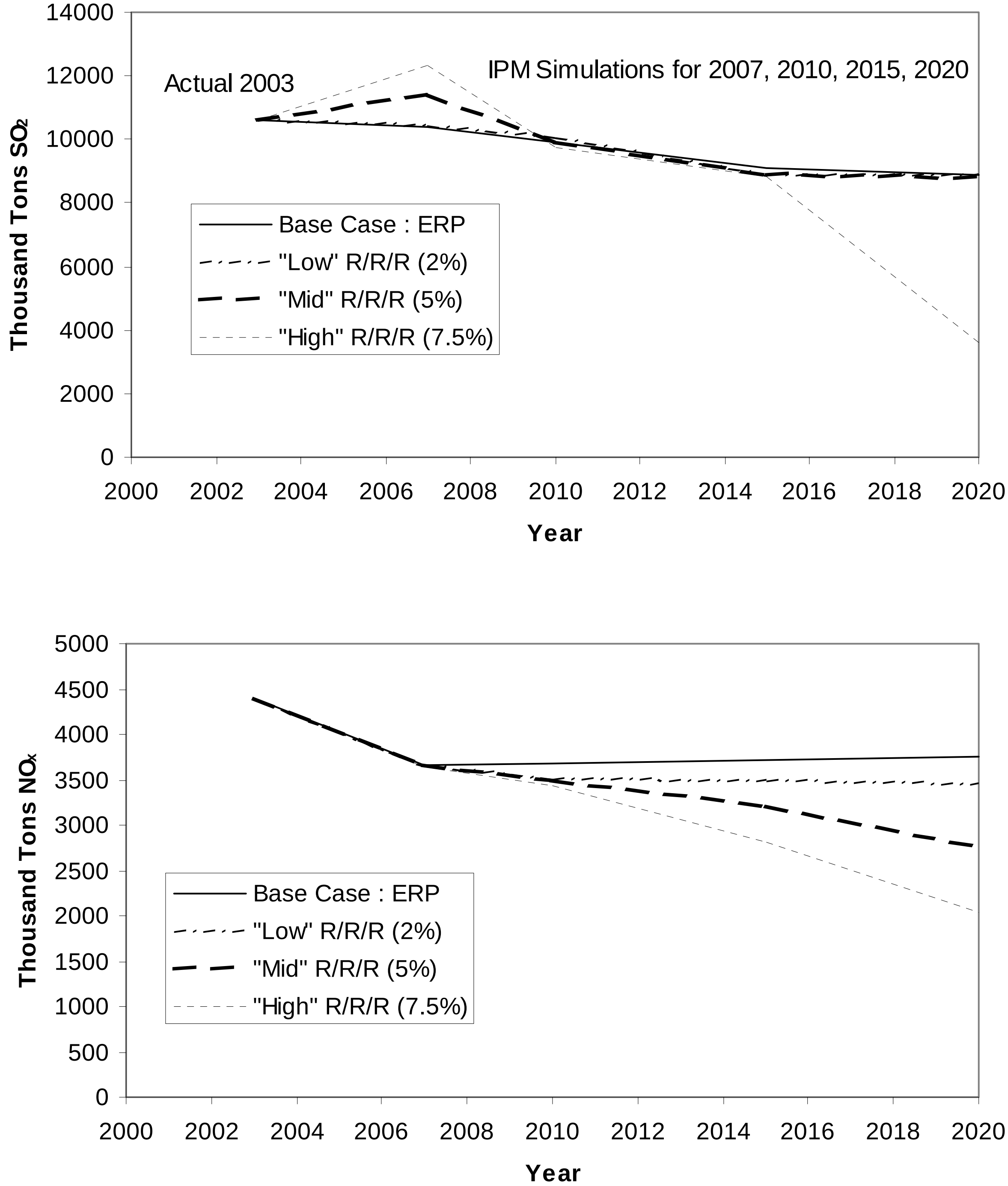
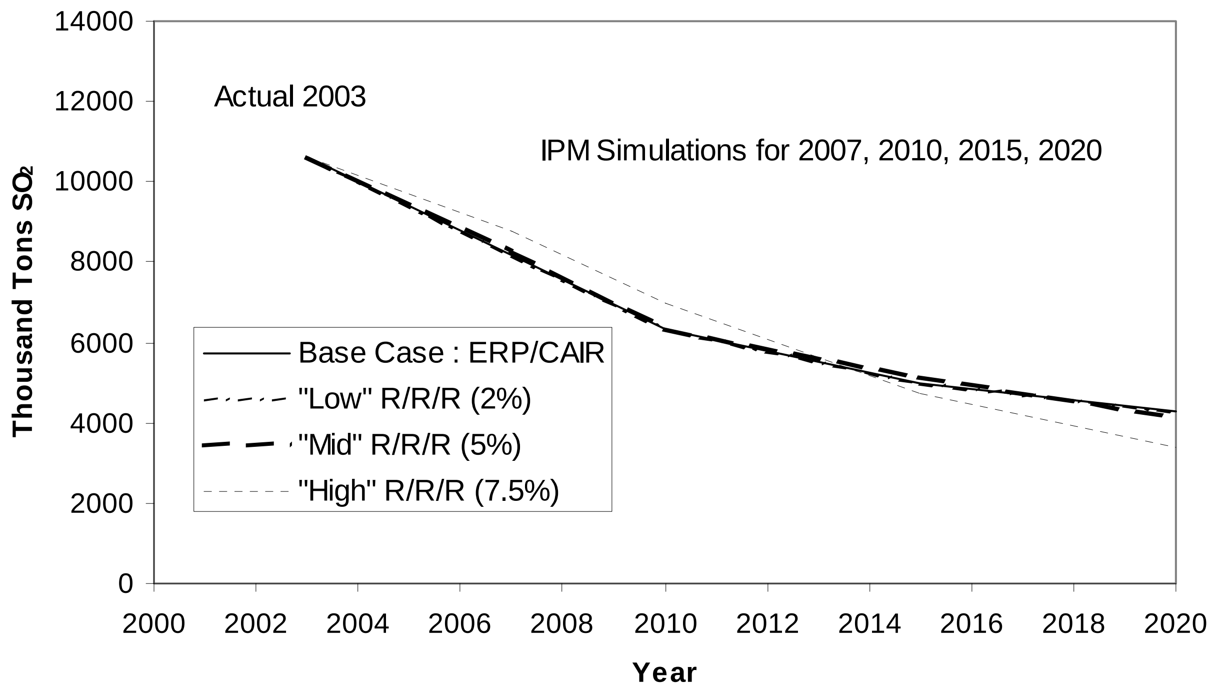


Figure 3. National SO_2 and NO_x Emissions, R/R/R and ERP Scenarios with CAIR



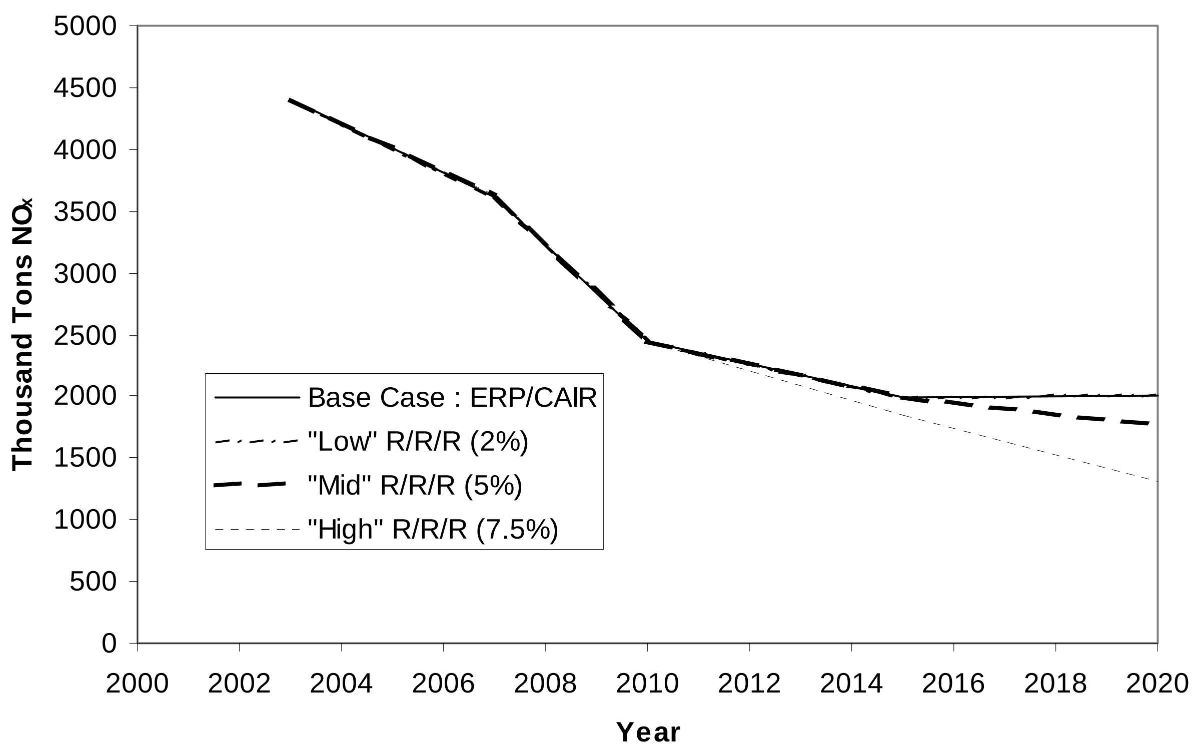


Table 1. Integrated Planning Model (IPM) Runs

<table>
<tr><th>Policy Setting</th><th>NSR Rule</th><th colspan="2">Run Name and Assumed Incentive Effects of NSR Rule</th><th>Notes</th></tr>
<tr><td rowspan="6">Without CAIR:
Title IV SO_2 and NO_x SIP Call programs only

or

With CAIR:
CAIR, CAMR, and BART programs as well as Title IV SO_2</td><td>ERP</td><td colspan="2">Base case: Motivates no additional pollution control retrofits. Avoidance does not affect performance of generators.</td><td>Assumed to generate equivalent incentives as the proposed hourly emission test for NSR applicability (EPA 2005d). Equivalent to EPA’s base-case runs of the IPM. Base-case runs assume that the incentives created by the NSR rule are minor for existing sources and are thus ignored.</td></tr>
<tr><td rowspan="5">Prerevision NSR (rules before ERP was promulgated)</td><td>Avoid</td><td>NSR avoided, resulting in a 0.1 percent per year deterioration in efficiency (heat rate) and capacity of generators</td><td>Follows U.S.EPA’s assumption of the incentive effects of the prerevision rule as reported in the ERP RIA (EPA 2002). Avoid scenario with CAIR, CAMR, and CAVR is not modeled</td></tr>
<tr><td>Low R/R/R</td><td>Each year from 2007 to 2020, $\geq$2 percent of the coal-fired capacity that did not have FGD or SCR as of 2006 must retrofit these controls, repower, or retire</td><td></td></tr>
<tr><td>Middle R/R/R</td><td>Same as low R/R/R, except percentage is 5 percent</td><td></td></tr>
<tr><td>High R/R/R</td><td>Same as low R/R/R, except percentage is 7.5 percent</td><td></td></tr>
<tr><td>High R/R/R, low investment cost</td><td>Same as high R/R/R except renewable and IGCC investment costs are lower</td><td>Sensitivity analysis exploring the effect of lower-cost nonemitting technologies on results. Analyzed only with the CAIR, CAMR, and CAVR policy setting</td></tr>
<tr><td>Emissions caps based on annual emissions from high R/R/R scenario</td><td>None</td><td colspan="2"></td><td>Sensitivity analysis exploring cost savings from using cap-and-trade programs to achieve emissions realized in high R/R/R scenario. Analyzed only with the CAIR, CAMR, and CAVR policy setting</td></tr>
</table>