ELECTRIC POWER
RESEARCH INSTITUTE

PRISM 2.0: THE VALUE OF INNOVATION IN ENVIRONMENTAL CONTROLS

SUMMARY REPORT

October 2012

INTRODUCTION

The Electric Power Research Institute (EPRI) has conducted a strategic analysis of key uncertainties confronting the existing U.S. coal-based generation fleet over the next few decades. Those uncertainties include the cost and availability of effective control technologies; current, proposed, and potential environmental control regulations; and the long-term price of natural gas. This review was initiated by EPRI to assist generating companies in understanding various technology options and costs scenarios as part of their asset management planning.

New regulations from the U.S. Environmental Protection Agency (EPA) affecting air emissions, cooling water usage, and solid waste disposal from electric power generation units are pending, and additional regulations can be expected later in the decade. Current and proposed regulations covered in this analysis include:

- Mercury and Air Toxics Standards (MATS) Rule[1] with compliance by 2015. This is considered a current regulation.
- Clean Water Act (CWA) 316(b)[2] for Cooling Water Intake Structures with compliance by 2018. This is a proposed regulation.
- Resource Conservation and Recovery Act (RCRA) regulation on Coal Combustion Residuals (CCRs)[3] with compliance by 2020. This is a proposed regulation.

Additional emissions limits, while not specifically proposed by EPA, were included in this analysis, and modeled to be in place by 2018. These limits serve as a proxy for impending and potential actions for compliance with the current 2008 and revised National Ambient Air Quality Standards (NAAQS) for ozone[4], the current 2010 NAAQS for sulfur dioxide (SO_2) and nitrogen oxide (NO_2), the Regional Haze Rule[5], and pending revisions on the NAAQS for Particulate Matter[6] .

Control technology costs for these current, proposed, and potential regulations can be estimated for each of the approximately 1,100 coal-fired generating units in the U.S., representing over 300 gigawatts (GW) of capacity and historically producing approximately 50 percent of total electricity generation. The unit-specific control technology cost estimates can then be applied in a new, regional model of the U.S. economy to evaluate the potential impact of these current, proposed, and potential environmental controls on the U.S. electric power sector, and by extension, the broader U.S. economy.

The price of natural gas is another significant uncertainty confronting the electric power sector, as well as other sectors of the economy which use natural gas as a key input. This analysis uses the projected natural gas prices from EIA's Annual Energy Outlook 2011[7] but also evaluates higher and lower price trajectories to show a potential range of impacts on power generation, in general, and coal unit retirements, in particular.

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[1] The MATS includes the National Emission Standards for Hazardous Air Pollutants (NESHAP) from Electric Utility Steam Generating Units and the revised New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units. www.epa.gov/mats and ww.epa.gov/ttn/atw/nsps/boilernsps/boilernsps.html
[2] http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/
[3] http://www.epa.gov/osw/nonhaz/industrial/special/fossil/ccr-rule/index.htm
[4] http://www.epa.gov/airquality/ozonepollution/designations/2008standards/regs.htm
[5] http://www.epa.gov/visibility/actions.html
[6] http://www.epa.gov/airquality/particlepollution/actions.html
[7] Energy Information Administration, U.S. Department of Energy; www.eia.gov/forecasts/aeo/

MODEL DESCRIPTION

The U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model combines a dispatch and capacity expansion model of the electric sector with a high-level, dynamic computable general equilibrium (CGE) model of the U.S. economy with sectoral detail in energy demand and transportation across 15 geographic regions. The two models are solved iteratively to convergence, allowing analysis of policy impacts on the electric sector taking into account economy-level responses. This makes US-REGEN capable of modeling on a regional basis a wide range of environmental and energy policies in both the electric and non-electric sectors. The Prism 2.0 collaborative project[8] was initiated in late 2010 to accelerate development of the US-REGEN model and to subsequently use it to analyze critical issues related to the electric sector, in particular, and also the broader U.S. energy sector.

The electric sector component of US-REGEN is a generation planning model and follows the standard approach of aggregating electric power units with similar attributes at the regional level. In each time step, the model makes decisions about capacity (e.g. new investment, retrofit, or retire) and dispatch to meet energy demand for both generation and inter-region transmission. It uses a bottom-up representation of power generation capacity and dispatch across a range of intra-annual load segments. It models transmission capacity between regions, and requires that generation and load plus net exports and line losses balance in each load segment and for each region.

The macroeconomic component of US-REGEN is a CGE model applied to the U.S. This uses a classical Arrow-Debreu general equilibrium framework to describe the entire economy over time, calibrated to observed U.S. economic data covering all transactions amongst firms and households, and forecasted economic growth into the future. Production in each sector is described by a constant elasticity-of-substitution (CES) production function. Firms are assumed to maximize profits, and households maximize utility, the latter assumed to be a function of consumption across the time span of the model. The model is designed to show how changes in policy impact economic activities relative to a baseline case.

The US-REGEN model uses a defined baseline which includes the following key inputs and assumptions:

- Economic growth and energy supply and demand based on EIA's Annual Energy Outlook 2011.
- Economic data from IMPLAN and electric power unit data from Ventyx based on 2009 and 2010 datasets, respectively, with 2010 serving as the model's base year.
- Electric sector policies which include state renewables portfolio standards as of December 2011, the Cross-State Air Pollution Rule (CSAPR)[9], but no specific state or federal carbon dioxide (CO_2) regulations[10], however, new coal plant additions are limited to units currently under construction.

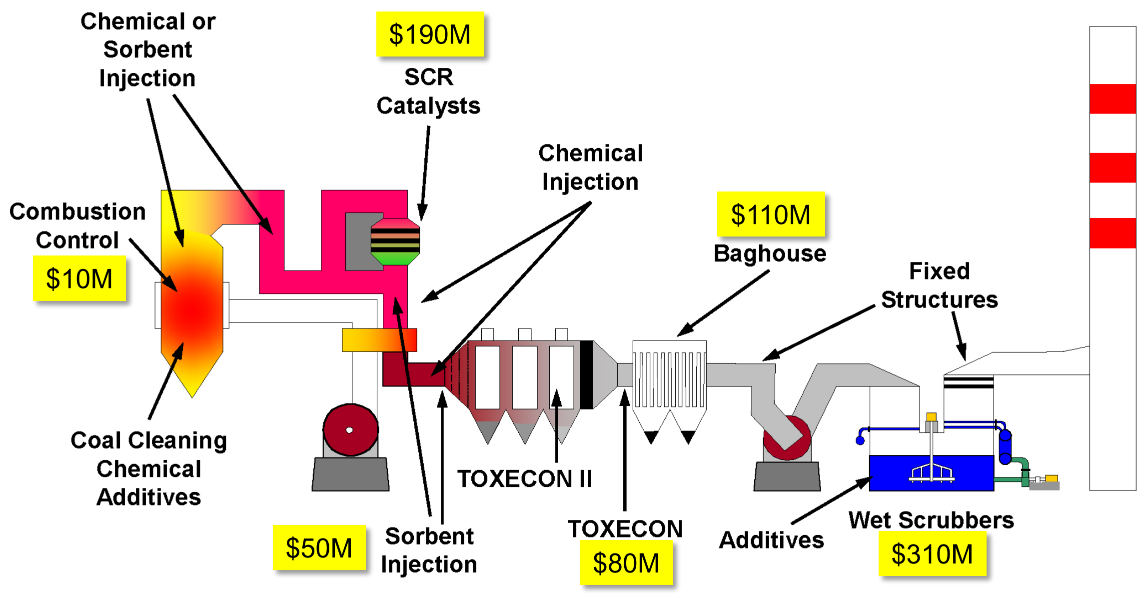
For additional details on the US-REGEN model, please go to http://globalclimate.epri.com.

[8] Note that the US-REGEN model is the analytical platform or tool we are using in the PRISM 2.0 project. At times people use the term 'PRISM 2 model' for ease of communication.
[9] CSAPR aims to reduce SO_2 emissions by 73 percent and NO_x emissions by 54 percent from 2005 levels by 2015. http://www.epa.gov/airtransport. The rule was vacated by the U.S. Circuit Court of Appeals on August 21, 2012, and EPA must continue to administer the predecessor Clean Air Interstate Rule (CAIR) under a CSAPR replacement is promulgated.
[10] Neither the Regional Greenhouse Gas Initiative (RGGI) nor the California AB 32 legislation is included. Federal Clean Air Act regulations addressing greenhouse gases are also not included.

ANALYSIS APPROACH

A defining characteristic of this analysis is that it assumes that generator asset owners make *a single retrofit-retire decision, effectively starting in 2015,* based on their best expectations of the controls required by current and proposed regulations, future commodity prices, CO_2 mitigation policy, as well as expectations of future, potential environmental regulations not yet proposed. For each unit there is a decision to either cease to operate as a coal unit, or to undertake a comprehensive program to meet current and anticipated regulatory requirements expected to be in force between 2015 and 2020. In our view, this mirrors the actual decision making process presently under way by generator asset owners, who must make decisions amid significant uncertainties including anticipated future environmental regulations, technology costs and availability, and the price of natural gas.[11] This reduces the total cost of controls by taking advantage of the co-benefits for mercury controls from stringent SO_2 and NO_x control. In practice this approach also has the benefits of economizing on plant engineering and controls optimization rather than making the retrofits changes in a piecemeal fashion over time.

Example Costs to Control Emissions from a Power Plant – 400 MW, Bituminous Coal



INPUT ASSUMPTIONS

The U.S. coal fleet is quite heterogeneous. The technology and economics of each unit are essentially unique, defined by the age and size of unit, coal type, the existence and configuration of pollution control equipment already in place, and the current pollution control performance of each unit. This can lead to a wide variation in retrofit costs from one unit to another. For this reason, we estimate the full retrofit costs (per our single retire-retrofit decision discussed above), on unit by unit basis. Recognizing the many uncertainties in technology effectiveness, cost pressure in markets for retrofit

[11] Numerous other analytical studies (e.g. EIA, NERC, Bipartisan Policy Center, NERA Consulting, & ICF) follow a similar approach to the one employed here. At the same time, it should be noted that there could be cases where a public utility commission only approves cost recovery for investments related solely to final, promulgated regulations. This level of company-specific decision making is beyond the level of detail captured in this analysis.

materials and installation services, and regulatory interpretation of acceptable technologies and compliance goals, we created a Reference Case as well as two alternative cases to test the impacts of a range of overall cost assumptions for the generation fleet:

- The **Reference Case** provides a central estimate of the retrofit investment costs, with a mix of wet and dry SO_2 scrubbing, selective catalytic reduction systems for NOx, modest incremental investment for Hg controls (given co-benefits of SO_2 and NOx control), retrofit of closed cycle cooling for all once-through systems, and coal combustion residual control management as a non-hazardous waste under RCRA. Retrofit costs are elevated above current/recent levels to reflect the market effect of a large amount of simultaneous retrofit required over the next 3-6 years.

- The **Flex Case** combines assumptions of more deployment of dry and sorbent-injection-based SO_2 control technologies (assumed to be equally compliant), lower cost, alternative entrainment management for those cooling systems on less sensitive water bodies, less escalation in retrofit costs, and an extended flexibility period for retrofitting SO_2, NOx and Hg controls.

- The **High Case** provides an upper bound estimate in this analysis based on more established but expensive wet SO_2 scrubbing, and higher cost escalation in the retrofit supply chain due to increased pressure on materials, labor, and other inputs.

The sections below provide more details on the differences between the three cases for each of the specific environmental controls covered in this analysis.

1. EPRI's IECCOST Model

To estimate the input costs required for SO_2, NOx and Hg controls, EPRI's IECCOST model[12] was employed. IECCOST is an economic analysis workbook that produces rough-order-of-magnitude cost estimates of the installed capital and levelized annual operating costs for stand-alone and integrated environmental control (IEC) systems installed on coal-fired power plants. The model allows for the comparison of cost information for conventional and developing SO_2, NOx, particulate matter, mercury, and IEC technologies, for both new plants and retrofit applications. Flue gas composition is calculated based on user inputs of general parameters, such as boiler operation, coal analysis, and economic factors. Flue gas composition and control technology input from the user are used as a basis for material balance calculations. Equipment sizes and capital costs are determined using material balances and cost vs. capacity parametric equations. EPRI cost estimating methodology is then used to calculate the total capital requirement, fixed and variable operating costs, and the levelized operating costs. Based on discussions with both buyers and providers of retrofit services, IECCOST inputs for market escalation and retrofit difficulty were varied across the Reference, Flex and High cost scenarios to reflect the inherent uncertainty in these cost drivers. The market escalation factor, sometimes referred to as environmental compliance cost escalation or supply-chain bottlenecking in other studies[13,14,15], can be difficult to quantify and apply in the type of analysis undertaken here. It is recognized that new environmental compliance requirements can create increased, short-term activity on environmental retrofits and hence drive up the demand and

[12] For more on the IECCOST model see http://my.epri.com/portal/server.pt?Abstract_id=000000000001020831
[13] North American Electric Reliability Corporation, "2011 Long-Term Reliability Assessment," Nov. 2011.
[14] Nicholas Institute for Environmental Policy Solutions, Working Paper 12-05, July 2012.
[15] The Brattle Group, Inc, "Supply Chain and Outage Analysis of MISO Coal Retrofits for MATS", May 2012.

costs for the associated labor, construction, and materials. The cost differences between the cases depend on the application of a particular technology, cost differences between the technologies, and lower escalation in the Flex case given the extended time for compliance. Details on the control cost assumptions for the Reference, Flex, and High Cases are in Tables 1a, 1b, and 1c below.

2. Mercury (Hg) Controls

The Reference and High Cases for mercury control assumes compliance by 2015, and that both activated carbon injection (ACI) and a fabric filter (FF) will be required for all units not initially in compliance. However, we recognize that the stringent SO_2 and NO_x control requirements (below) confer co-benefits for Hg control. Units with both SO_2 controls and selective catalytic reduction (SCR) controls for NO_x therefore may face only modest costs for sorbent injection and particulate control upgrades. The few units that meet the NO_x threshold without an SCR are assumed to require both ACI into the flue-gas stream for mercury absorption, and a FF unit to trap the mercury-absorbed particles along with other particulates. In the Flex Case, the EPRI integrated mercury removal process Toxecon™ (see last section for more information) is assumed to be an available option.

The timing of the controls for the Reference and High cases is based on the MATS required compliance date of 2015 (or three years after the 2012 final rule). The Flex timing to 2017 is based on the potential two additional years to phase in compliance that may be granted by the state permitting authorities subject to specific criteria and by an EPA administrative order.

3. Sulfur Dioxide (SO_2) Controls

The analysis uses an assumption that owners of coal units make their retrofit-retire decision based on a SO_2 limit of 0.15 lb/MMBtu across the three cases. The Reference and High Cases assume compliance by 2015, with the Flex case by 2017. The MATS rule allows an alternate equivalent SO_2 emissions standard for 0.20 lb/MMBtu heat input as a surrogate for acid gases (see Table 5 of the rule preamble). The 0.20 lb/MMBtu limit was lowered to 0.15 lb/MMBtu as a design basis in consideration of current, proposed, and scheduled regulations on sulfur dioxide, particular matter, and regional haze. Units not meeting this threshold will require SO_2 controls. For those units already with SO_2 controls, additional upgrades may still be necessary if their emission rates surpass the 0.15 lb/MMBtu threshold. For those units that already perform at or under this limit, no further remedies are required.

In the High Case, units that do not meet this 0.15 lb/MMBtu limit will need to have full flue gas desulfurization (FGD) technology and associated wastewater treatment (WWT). For units with existing FGDs, upgrading (at lesser cost) may still be necessary if performance does not meet the 0.15 lb/MMBtu threshold. The Ref and Flex cases relax the FGD requirements, dependent on the type of coal used. For units burning Western sub-bituminous and lignite coals the full FGD requirement is relaxed and less costly solutions are assumed to be compliant, for example dry sorbent injection and lime spray drying technologies. For higher sulfur, Eastern bituminous coal, the lowest investment cost technology (dry sorbent injection) is unlikely to be economic due to a much higher operating cost.

Table 1a: Reference Case Retrofit Cost Assumptions for SO_2, NOx and Hg Control Technologies

Control Technology	FGD w/WWT	LSD	FGD upgrade	SCR	SCR upgrade	ACI	ACI + FF
Pollutant	SO_2	SO_2	SO_2	NOx	NOx	Hg	Hg
Coal Options	Bit	Sub, Lig	All	All	All	All	All
% Capture	98%	95%		70%		75%	75%
Capital Cost ($/kW)							
300 MW	$920	$643		$538		$23	$312
500 MW	$691	$499	$150	$424	$100	$16	$279
700 MW	$572	$422		$362		$13	$260
FOM ($/kW-yr)	$25	$17		$5		negligible	$4
VOM ($/MWh)	$4.0	$2.7		$1.5		negligible	negligible

Fixed operations and maintenance (FOM) costs; Variable operations and maintenance (VOM) costs; Flue gas desulfurization (FGD); wastewater treatment (WWT); lime spray drying (LSD); selective catalytic reduction (SCR); Activated Carbon Injection (ACI); Fabric filter (FF).

Table 1b: Flex Case Retrofit Cost Assumptions for SO_2, NOx and Hg Control Technologies

Control Technology	LSD	DSI	FGD upgrade	SCR	SCR upgrade	Toxecon
Pollutant	SO2	SO2	SO2	NOx	NOx	Hg
Coal Options	E. Bit	Sub, Lig	All	All	All	All
% Capture	95%	90%		70%		
Capital Cost ($/kW)						
300 MW	$320	$116		$437		$158
500 MW	$241	$87	$100	$344	$50	$137
700 MW	$199	$72		$294		$124
FOM ($/kW-yr)	$17	$2		$5		$2
VOM ($/MWh)	$2.0	$7.1		$1.5		negligible

Fixed operations and maintenance (FOM) costs; Variable operations and maintenance (VOM) costs; Flue gas desulfurization (FGD); dry sorbent injection (DSI); lime spray drying (LSD); selective catalytic reduction (SCR).

4. Nitrogen Oxides (NOx) Controls

The analysis uses an assumption that owners of coal units make their retrofit-retire decision based on a NOx limit of 0.10 lb/MMBtu heat input across the three cases. The Reference and High Cases assume compliance by 2018. The MATS rule did not use NOx as a surrogate for any air toxics emissions; as a result, limit on the design basis was determined in consideration of current, proposed, and scheduled regulations on nitrogen oxides, ozone, particulate matter and regional haze. Units not meeting this threshold will require selective catalytic reduction. For those units already with SCRs, additional upgrades may still be necessary if their emission rates surpass the 0.10 lb/MMBtu threshold. For those units that already perform at or under this limit, no further remedies are required. The Flex timing to 2020 for NOx controls is based on different deadlines for compliance with state implementation plans for current NAAQS for ozone and NO_2 and potential future NAAQS for ozone.

Table 1c: High Case Retrofit Cost Assumptions for SO_2, NOx and Hg Control Technologies

Control Technology	FGD w/WWT	FGD upgrade	SCR	SCR upgrade	ACI	ACI + FF
Pollutant	SO2	SO2	NOx	NOx	Hg	Hg
Coal Options	All	All	All	All	All	All
% Capture	98%		70%		75%	75%
Capital Cost ($/kW)						
300 MW	$1,041		$616		$27	$376
500 MW	$777	$200	$485	$150	$19	$336
700 MW	$640		$414		$15	$313
FOM ($/kW-yr)	$25		$5		negligible	$4
VOM ($/MWh)	$4.0		$1.5		negligible	negligible

Fixed operations and maintenance (FOM) costs; Variable operations and maintenance (VOM) costs; Flue gas desulfurization (FGD); wastewater treatment (WWT); selective catalytic reduction (SCR); Activated Carbon Injection (ACI); Fabric filter (FF).

5. Cooling Water

All three cases assume a 2018 deadline for compliance with the requirements of Clean Water Act Section 316 (b)[16]. Units with a flow rate of more than 125 mgd (million gallons per day) of cooling water with once-through cooling technology are assumed to be required to switch to closed-loop cooling towers instead. Unit-specific costs for each coal-fired unit were estimated in an EPRI-commissioned study.[17] These estimates represent for each unit the total cost to install cooling towers as a substitute for once-through cooling. Notice that approximately half of the fleet (150 GW) will incur no costs because these units already use closed-loop cooling. As well, there are a few units in the fleet where retrofit is judged to be simply infeasible. These units are arbitrarily assigned prohibitive cost estimates.

In the Flex case, we assume that only ocean, estuary, tidal river, and small river plants will require closed cycle cooling, consistent with EPA's proposed 316(b) rule in March 2011, where cooling towers were not defined as "Best Available Technology" across the board on all plants. Units not situated on the ocean, estuaries, tidal rivers, or small rivers can instead make retrofits to reduce impingement and entrainment of aquatic species at an assumed 10 percent of the full cooling tower retrofit cost.

[16] In a recent modified settlement agreement for the proposed 316(b) regulations, EPA indicated that it is working to finalize the standards by June 2013. As a result, requirements of the rule would have to be implemented as soon as possible or by 2021 at the latest (8 years after the final rule).
[17] "Closed Cycle Retrofit Study: Capital and Performance Cost Estimates", EPRI Report 1022491, 2011

6. Coal Combustion Residuals

The Reference Case assumes treatment of Coal Combustion Residuals (CCRs) under Subtitle D of the Resource Conservation and Recovery Act (RCRA). This will require many generating units to install dry ash handling and disposal. Unit-specific costs were estimated by EPRI based on a site-by-site quantification of fixed and O&M costs for complying with Subtitle D under the non-hazardous waste classification[18]. Costs are assumed to be the same in the Flex and High cases.

7. Total Retrofit Investment Costs

The resulting three sets of combined unit-specific estimated retrofit costs (Flex, Ref, High) were used as inputs to the US-REGEN model to assess the potential impacts of current, proposed, and potential environmental controls the on the electric power sector and the U.S. economy out to 2035. The model can incorporate these additional costs of future operation, and estimate the likely changes in unit dispatch, net revenue, and profitability, enabling an informed decision on whether to retrofit each unit with the required pollution controls or retire the unit.

In the solution process the model picks the lowest cost compliance strategy which will include a mix of retrofits, retirements, conversions to natural gas, and additions of new generation. As US-REGEN is a full macroeconomic model of the U.S. economy, it also captures the effect of these added pollution control costs on the power sector in terms of changes in electricity generation, capacity, expenditures, and ultimately electricity prices. In general, the required additional expenditures in the power sector lead to higher prices for electricity and natural gas, which correspondingly reduce economic output.

Figure 1 shows the distribution of retrofit costs input to US-REGEN. It plots total scenario compliance costs for SO_2, NOx, Hg, 316b, and CCR controls, by individual generating units for over 1,000 coal units. For each cost scenario, the units were sorted by increasing costs and plotted against the cumulative coal generating capacity. The plot shows that almost 250 GW of the coal generation fleet in the Reference case could be made compliant in 2020 for $1,000/kW, but that some units will face costs several times that. The highest cost units are typically small, burn bituminous coal, and have fewer existing controls.

[18] "Cost Analysis of Proposed National Regulation on Coal Combustion Residuals from the Electric Generating Industry", EPRI Report 1022296, 2010, with cost mapping to individual units by Veritas Economic Consulting.

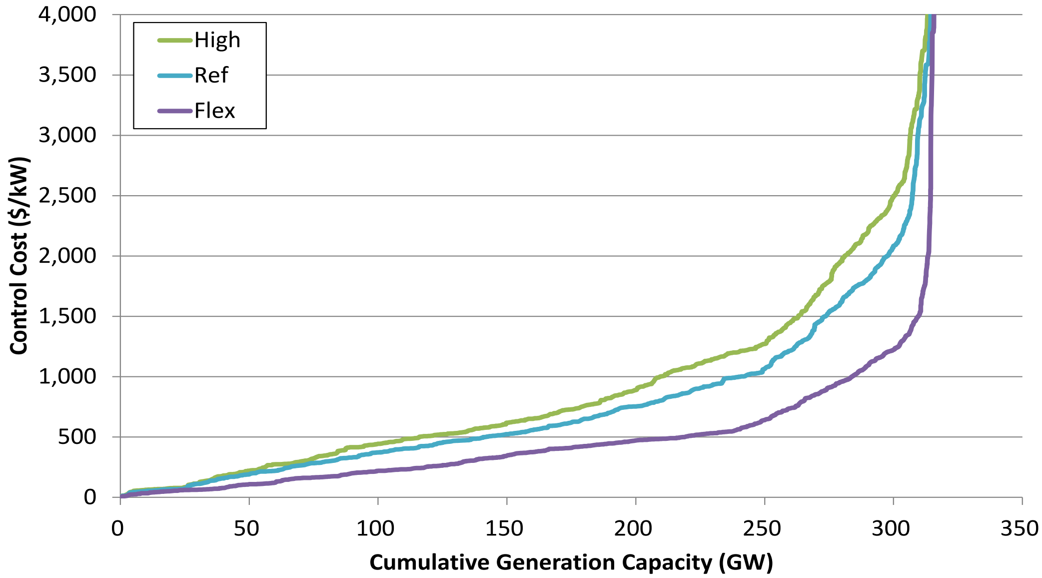


Figure 1. Range of Estimated Total Retrofit Investment Costs

ANALYSIS RESULTS

1. Electricity Generation

Figure 2 shows the mix of electricity generation in terawatt[19] hours (TWh) from 2010 to 2035 in the Reference Case. Key results in the Reference Case includes the substantial retrofit of existing coal (light blue); the addition of new nuclear generation starting in 2020 and continuing throughout the time period; and the steady increase of wind energy generation due to assumed cost declines in renewable power technologies and the reference natural gas price. Existing state renewables portfolio standards are in place; however there are no production credits or subsidies included for any generation technologies in this analysis. The model does capture changes in demand for electricity given changes in electricity prices (see Economics section) but the impact on generation is not appreciable.[20]

For comparison, the share of electric power generation in 2015 is coal at 38 percent, natural gas at 30 percent, nuclear at 20 percent, and renewables at the remaining 13 percent. The projected composition for 2035 is as follows: coal at 28 percent, natural gas at 25 percent, nuclear at 21 percent, and renewables, taking the largest gain in percentage terms, doubling to 26 percent.

[19] Terawatt (TW) = 1 trillion or 10^{12} watts

[20] The current version of the US-REGEN model does not have specific, detail representation of energy efficiency options; however, efforts are underway to include these options in the next version.

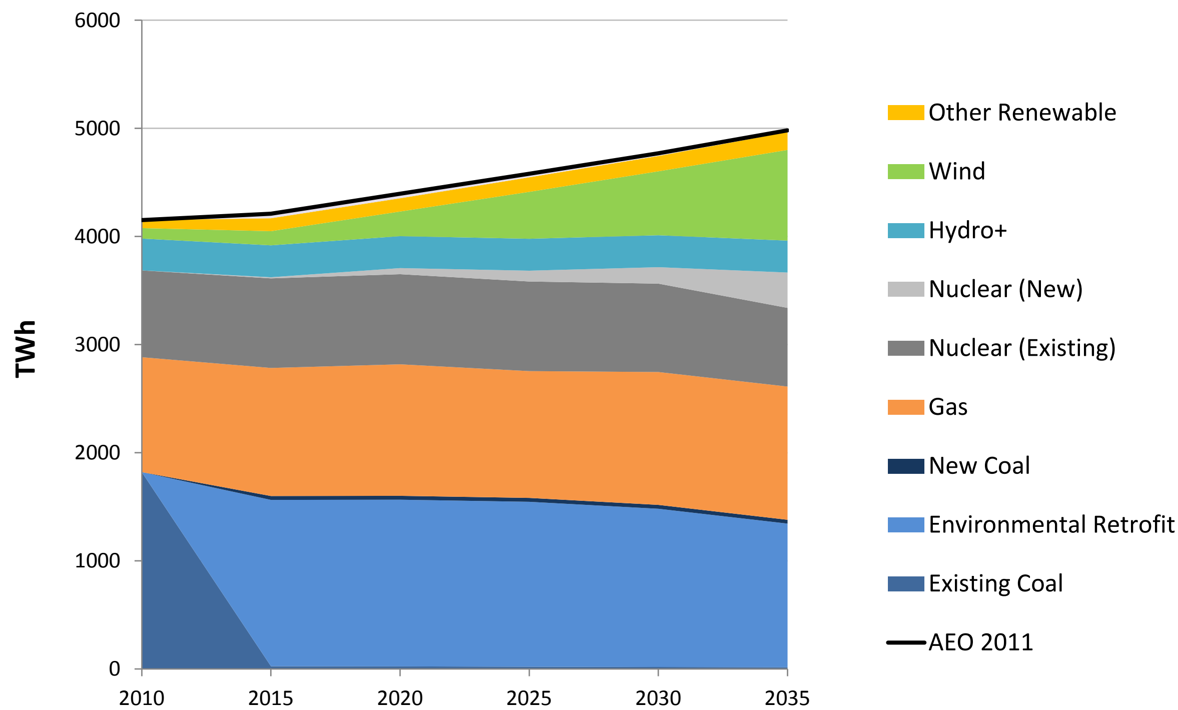


Figure 2. U.S Generation Mix in Reference Case

Generation results from a regional perspective are shown in Figure 3. The East and South regions show the greatest changes in future generation mix given that coal makes up a greater overall share of existing electricity generation. Coal unit retirements in these regions lead to a decline in overall coal generation by 2015, replaced by a slight increase in natural gas generation in the early periods and then by new renewables in the East and new nuclear power in the South region. The Midwest region shows relatively fewer impacts to the total amount of coal generation over time, with considerable growth in wind energy generation starting in 2020. The West, which has the lowest share of coal generation, shows lesser impacts with continued generation across coal, natural gas, and especially hydro and wind energy generation. Note that the model assumes it can build additional transmission as justified by its economic value in minimizing the total cost of serving load.

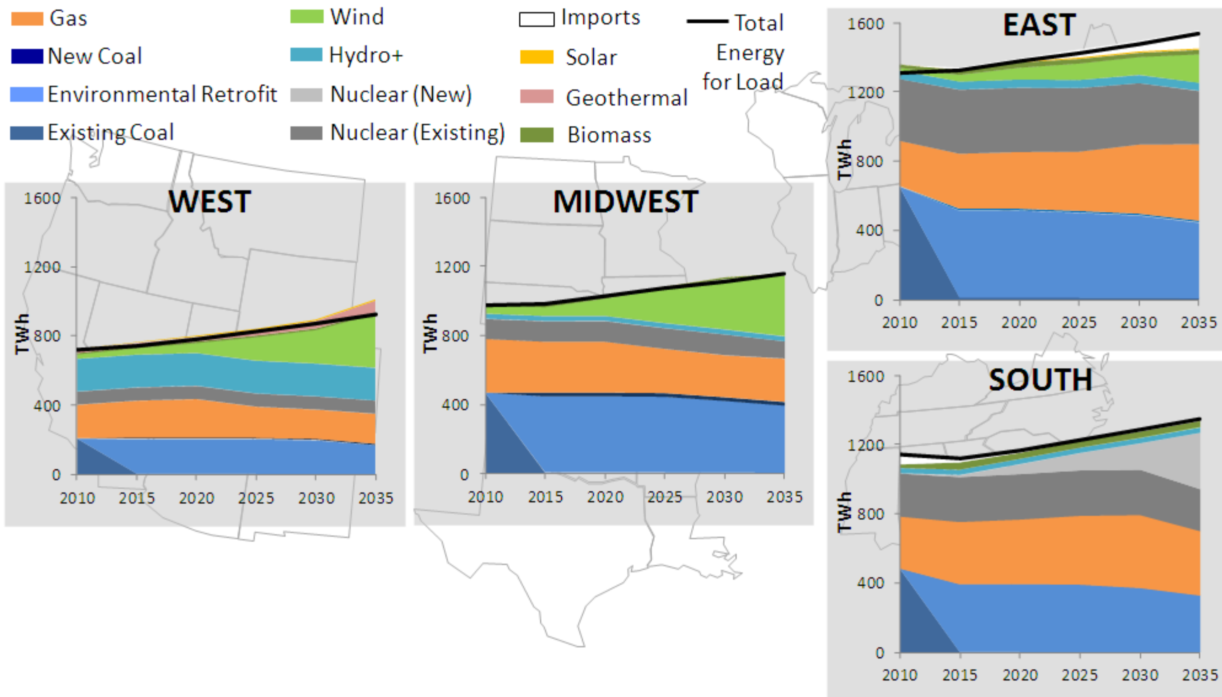


Figure 3. Regional Generation Mix in Reference Case

2. Coal Generation Capacity

Figure 4 illustrates the changes in the coal generation fleet due to the impact of the environmental controls costs under the Reference Case by 2020[21]. Notably, approximately 227 GW of existing coal capacity remains economically viable with estimated payback times of less than 5 years on the required environmental investment. Another 57 GW of coal capacity – primarily the older, smaller, less efficient units – would not be economically viable if the required environmental controls were installed and therefore are retired instead of retrofit. The remaining 28 GW of coal capacity will be either retired or retrofit depending on a number of market-specific factors such as cost recovery, regional unit specific decisions, changes in power market prices, whether demand for electricity is flat or increasing, price of natural gas, etc.

[21] Coal-fired plant owners and operators are already making operational decisions and have reported to EIA that about 30 gigawatts (GW) are to be retired between 2012 and 2016. www.eia.gov/electricity/data/eia860/index.html

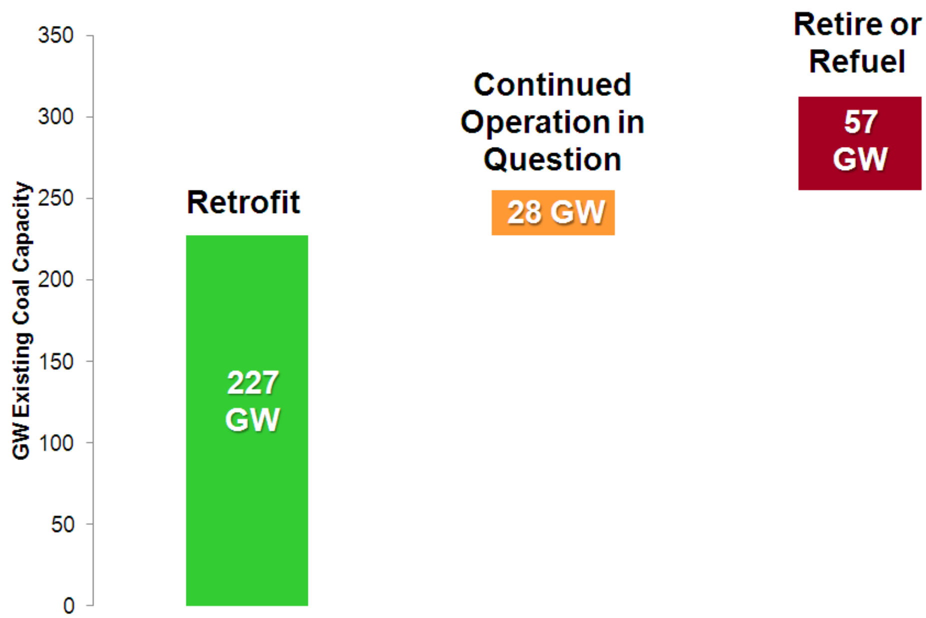


Figure 4. Changes in Coal Generation Capacity: Reference Case (2020)

In the High Case (Figure 5), higher retrofit costs due to the combined effect of higher cost control technologies deemed required, and higher cost escalation for labor and materials reduces the number of the existing coal units that can comply with the regulations while maintaining economically viable operations. Only 203 GW of retrofits occur in the High Case, compared to 227 GW in the Reference Case. In addition, the number of units with "continued operation in question" nearly doubles – to 54 GW – versus the Reference Case.

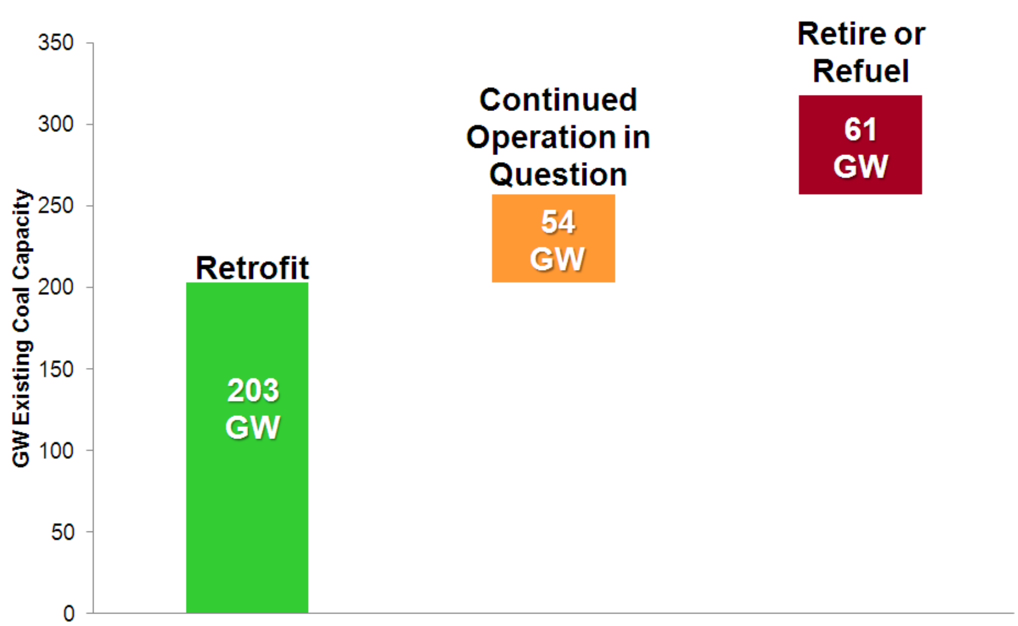


Figure 5. Changes in Coal Generation Capacity: High Case (2020)

In the Flex Case (Figure 6), the extended period of time for compliance and the availability of lower-cost control technologies enable a greater number of the existing coal units to comply with the regulations while maintaining profitable operations. Compared to the 202 GW of retrofits in the High Case, 288 GW of retrofits occur in the Flex Case. Far fewer units are expected to retire or switch fuels (36 GW compared to 61 GW) and even fewer units are subject to the uncertainty of whether continued operations will be economic subject to other market factors (5 GW versus 54 GW).

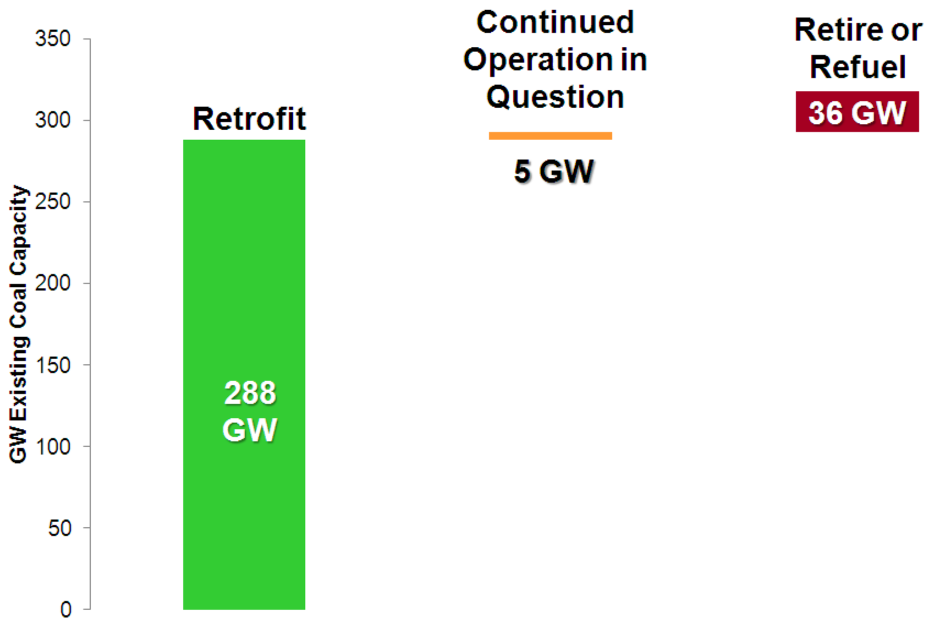


Figure 6. Changes in Coal Generation Capacity: Flex Case (2020)

3. Emissions

With respect to environmental outcomes, all three cases are modeled to achieve the same SO_2 and NO_x emissions rates once the set of current, proposed, and potential environmental rules are fully implemented. In the Flex Case, there are additional cumulative emissions of SO_2 and NO_x to the atmosphere as a result of the extended period for compliance (Figures 7a &b). In 2020, the resulting emissions in the three cases are about 50 percent lower than baseline levels for NOx and about 70 percent lower for SO_2

Emissions of CO_2 (Figure 8) continue to decline in the baseline given two important assumptions. First, an assumption is made in this analysis that existing coal plants are forced to retire once they reach 70 years of operation. Second, an assumption is made that new coal plant additions will be limited only to units currently under construction. Even though no specific state or federal CO_2 regulations are included in this analysis, the “no new coal” assumption is based on the uncertainty of state implementation of the current Prevention of Significant Deterioration (PSD) program under the Clean Air Act[22] and the expectation additional federal regulation of CO_2[23]. The resulting CO_2 emissions follow the projected electricity generation mix in the three cases with declines in coal, slight increases in natural gas, and greater increases in nuclear and renewable power generation.

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[22] http://www.epa.gov/nsr/ghgpermitting.html.

[23] EPAs’ proposal for Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, (March 27, 2012) is not included in this analysis.

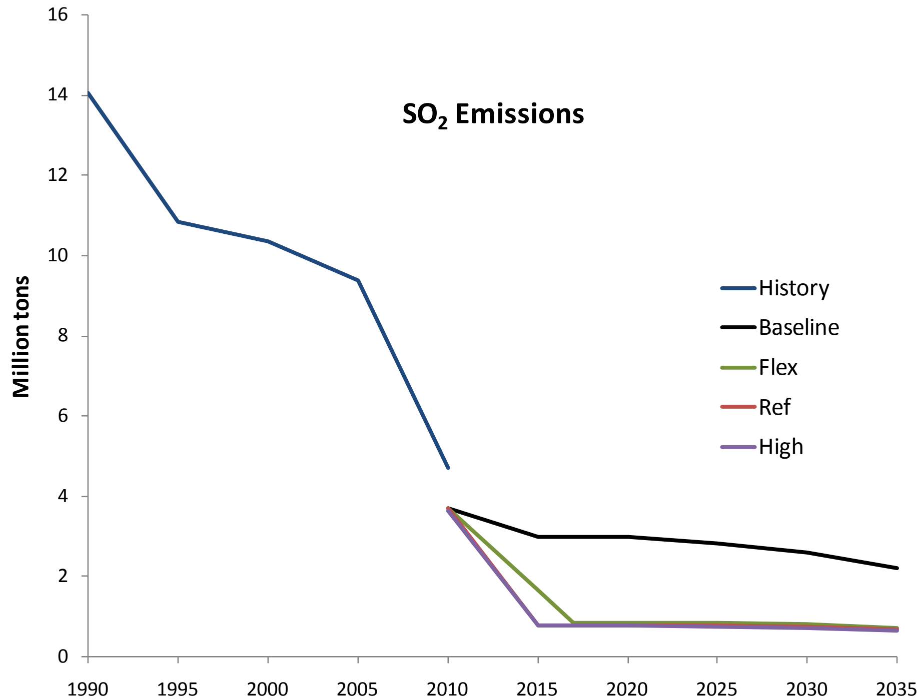

Figure 7a. Past and Projected Trends in Power Sector SO_2 Emissions

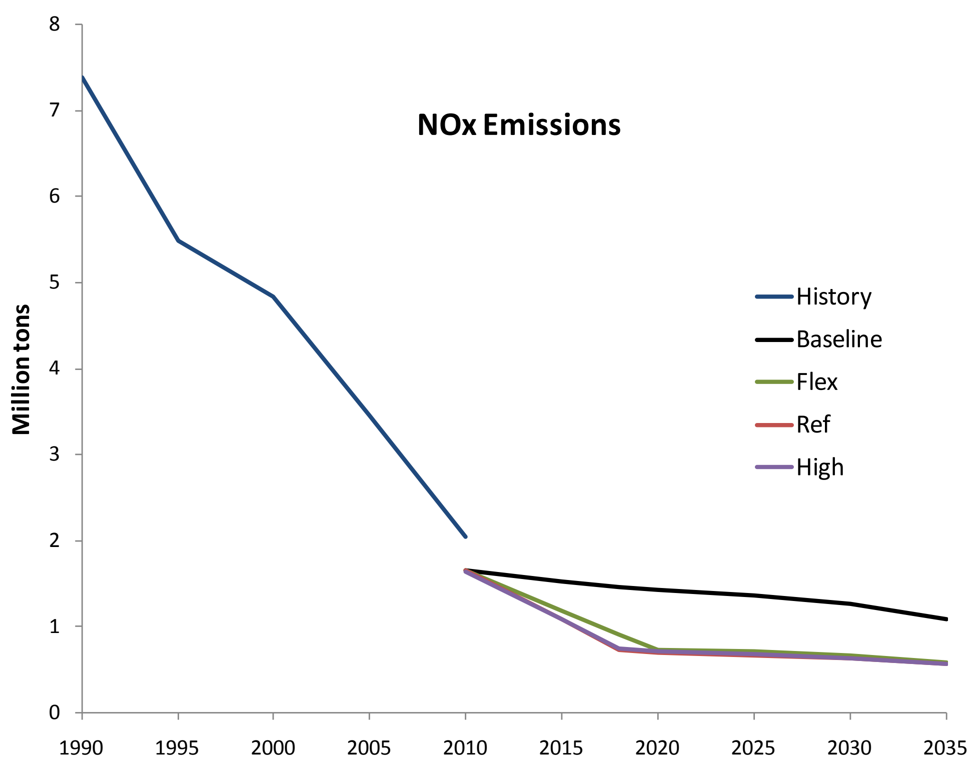

Figure 7b. Past and Projected Trends in Power Sector NOx Emissions

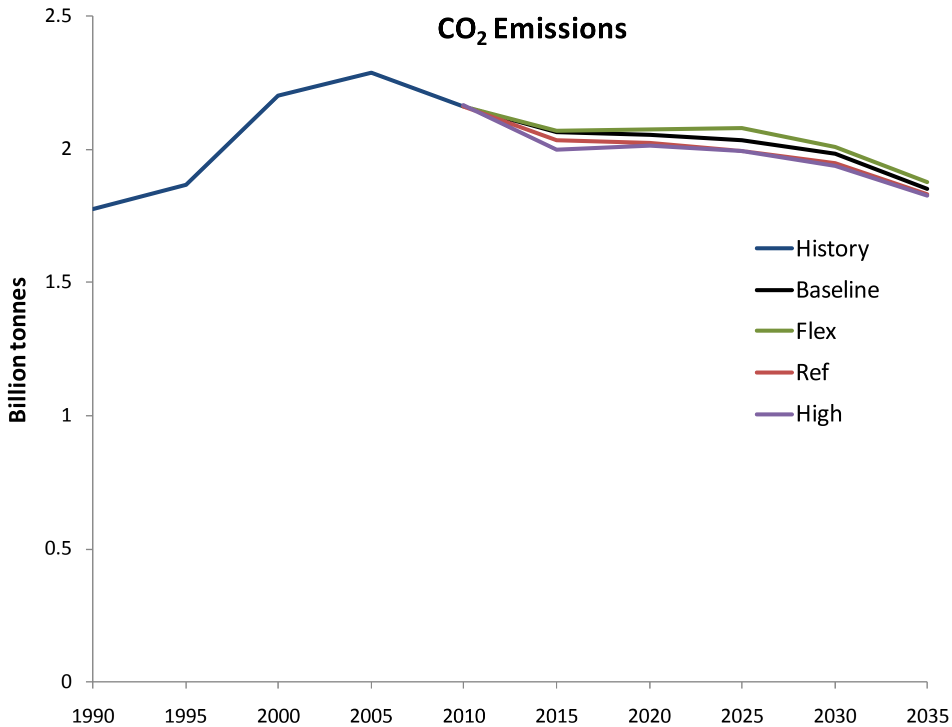

Figure 8. Past and Projected Trends in Power Sector CO_2 Emissions

4. Economics

A summary of the economic impacts of the current, proposed, and potential environmental controls is presented in Table 2. The difference in the economy-wide impacts of the Flex Case versus the High Case is estimated to be about $100 billion, in present value terms over 25 years. This $100 billion difference in GDP impacts can be broken down into specific components as follows:

- 28% for the flexibility in choice of environmental controls technologies
- 25% for lower cost of compliance with the Clean Water Act 316(b) requirements
- 38% for reduced capital and labor cost escalation associated with the extended period of time for retrofit installations affecting potentially 200 GW of the coal fleet
- 9% for the difference in compliance timing (later years cost slightly less in real dollar terms)

Table 2: Summary Economic Results from Current, Proposed and Potential Environmental Controls on the U.S. Electric Power Sector (incremental to the baseline)

Annualized Power Sector Expenditures 2010-2035[24]	**Power Sector Expenditures** (present value 2010-2035)[8]	**Retail Price Impacts** (national average)	**Economy-wide Impacts[25]** (present value 2010-2035)
$10 to $16 billion for retrofits, new capacity, incremental fuel/O&M	$140 to $220 billion for retrofits, new capacity and fuel/O&M (with more than half of the expenditures occurring by 2020)	4.5% - 8% in 2015 3.8% - 6.5% in 2020	$175 to $275 billion

5. Sensitivity to Natural Gas Prices

As described previously, the US-REGEN model uses natural gas price projections from the EIA's Annual Energy Outlook 2011 as in its Baseline. These natural gas prices are shown in Figure 9 as the Reference Case ("Ref"; corresponding to an average 2010-2035 price of $6.50/MMBtu). However, actual natural gas prices have been extremely volatile in recent decades, varying at times by several dollars above or below the EIA AEO projections. To better understand the potential interplay between natural gas prices and coal unit retirements, we explicitly varied the natural gas price trajectory in the model by ± $2 dollars from the EIA AEO 2011 baseline (Figure 9). As Figure 10 illustrates, movements in gas price projections have a material impact on the projected level of coal-fired asset retirements. For the reference gas price projection, there is about 55 GW of coal capacity that ceases to operate as coal, that is, those units are either retired or refueled (converted) to natural gas. In the higher natural gas price projection of +$2 from the reference (or about $8.50/MMbtu as an average over the period) there is about 30 GW that retire or refuel. At the other end of the modeled range, the -$2 from the reference (or about $4.50/MMbtu average) the projected retire or refuel change is over 100 GW of existing coal capacity.

[24] A real discount rate of 5 percent is used in these calculations.
[25] Economy-wide impacts do not include estimates for health or environmental benefits resulting from the regulations.

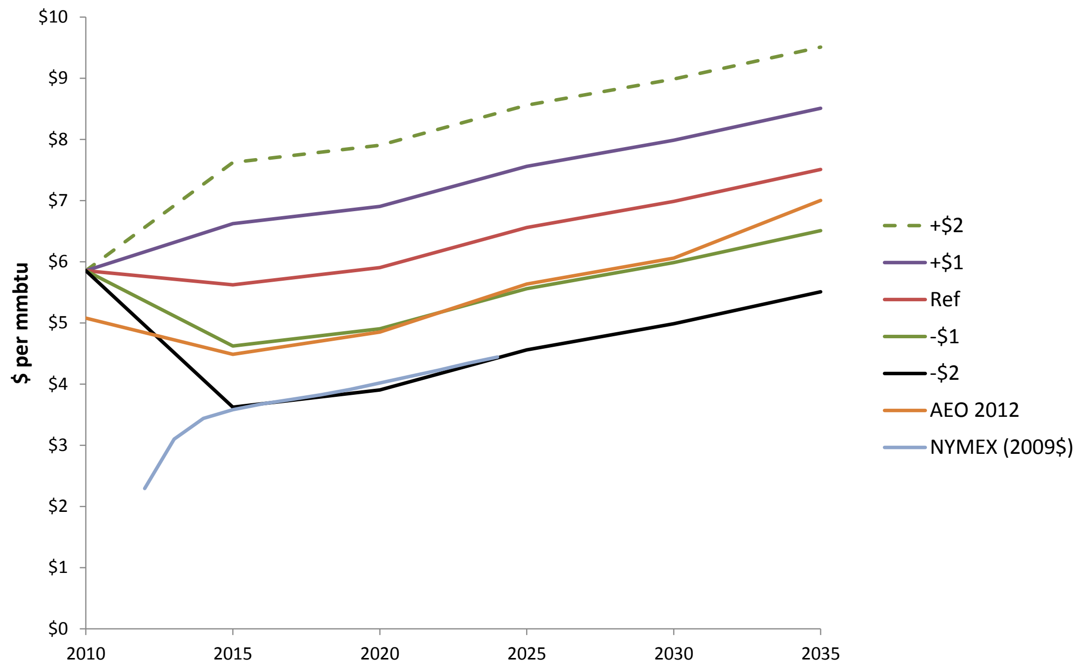

Figure 9. Natural Gas Price Scenarios for Sensitivity Analysis

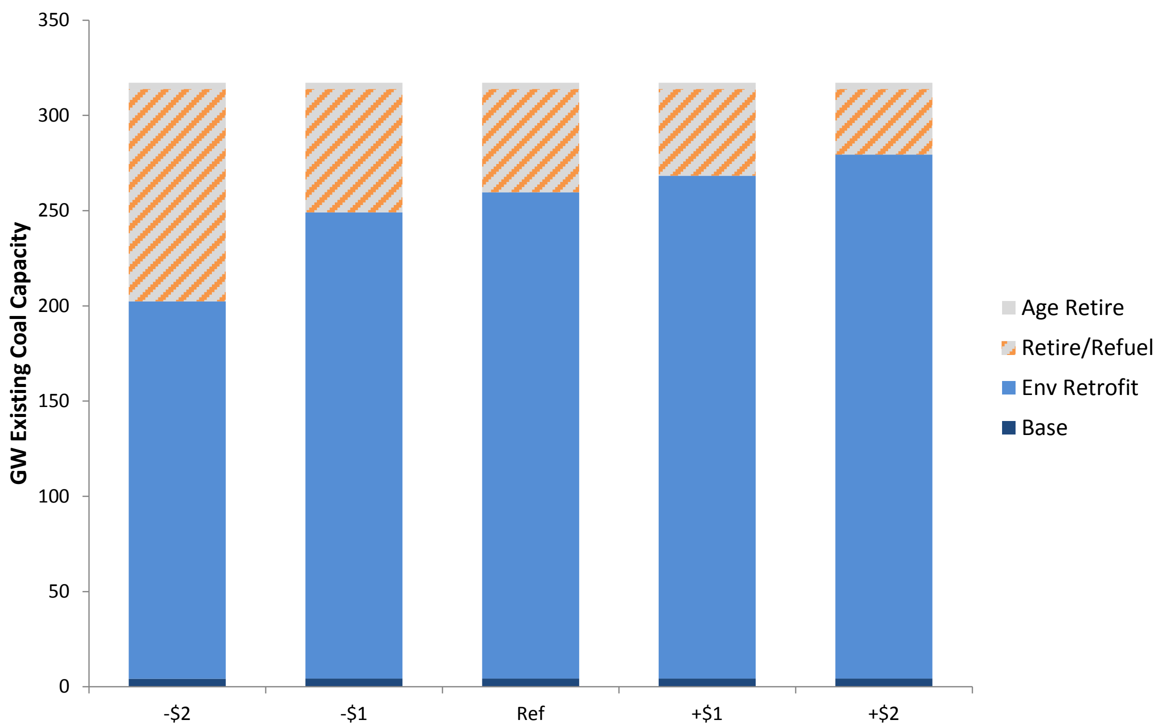

Figure 10. Disposition of Existing Coal Capacity in 2020 by Gas Price Scenario

ADVANCED TECHNOLOGIES

Realizing lower compliance costs for current and potential future environmental control regulations will require significant innovation and optimization in emissions control technology relative to today's technology options. Examples of advanced pollution control technologies that, in EPRI's view, may be made commercially available in the near term as part of an accelerated demonstration and deployment effort include:

- ***PMScreen:*** An innovative filtration concept developed and patented by EPRI, being demonstrated at sites to meet more stringent particulate matter emission requirements for units with underperforming ESPs. This "polishing" technology is particularly important for plants using activated carbon upstream of an undersized ESP where even small particulate matter increases can trigger New Source Review, necessitating expensive ESP upgrades. The technology involves installation of a modular filter assembly within the outlet cone of an existing ESP. The modular filter assembly is a self-contained unit capable of continuous operation within the duct environment. Filter material is mounted to a moving wire support belt that allows continuous cleaning of the filter while in service.
- ***Advanced SCR Systems:*** Enhancements to selective catalytic reduction (SCR) systems can result in increased NOx removal rates over a wider range of plant operating ranges. Advanced instrumentation and controls can optimize combustion and reduce emissions to very low levels.
- ***Sorbent Activation Process:*** Presently mercury control can be achieved by injecting activated carbon to bind with the mercury in flue gas, allowing removal via a fabric filter or electrostatic precipitator. A new EPRI process creates activated carbon from the coal itself, allowing considerable cost savings compared to existing methods.
- ***TOXECON:*** A demonstrated commercially available EPRI/NETL-developed process in which sorbents, including powdered activated carbon for mercury control and others for trace metals and acid gas control, are injected into a pulse-jet baghouse installed downstream of the existing particulate control device (i.e., ESP). The TOXECON configuration allows for the preservation of the ash sales.
- ***GORE Mercury Control System***: An EPRI/GORE-developed and licensed technology based on fixed-structure mercury sorbents that is intended to be integrated into an existing FGD to provide mercury and SO2 "polishing". Due to the unique chemistry employed, the novel sorbent polymer composite material is insensitive to process or fuel changes that impact mercury speciation and to common sorbent "poisons" such as SO3 and water. This potentially allows it to continually reduce mercury concentrations in a gas stream for years before needing replacement.
- ***Advanced Coal Cleaning:*** Pre-treatment of coal prior to combustion can effectively remove pyrites, ash, trace metals, and other pollutant forming matter from raw fuels which in-turn, helps reduce formation of numerous emissions, such as SOx, NOx, mercury, and particulates.

Even if there is insufficient time in the current set of regulations to bring these technologies to commercial deployment, continued research and development can help to ensure that these technologies (and others like them) will be available for generation asset owners when the next set of environmental controls regulations are inevitably put forth.

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