United States
Environmental Protection
Agency

MARKAL Scenario Analyses of Technology Options for the Electric Sector

The Impact on Air Quality

EPA/600/R-06/114
September 2006

MARKAL Scenario Analyses of Technology Options for the Electric Sector: The Impact on Air Quality

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Foreword

The U.S. Environmental Protection Agency (EPA) is charged by Congress with protecting the Nation's land, air, and water resources. Under a mandate of national environmental laws, the Agency strives to formulate and implement actions leading to a compatible balance between human activities and the ability of natural systems to support and nurture life. To meet this mandate, EPA's research program is providing data and technical support for solving environmental problems today and building a science knowledge base necessary to manage our ecological resources wisely, understand how pollutants affect our health, and prevent or reduce environmental risks in the future.

The National Risk Management Research Laboratory (NRMRL) is the Agency's center for investigation of technological and management approaches for preventing and reducing risks from pollution that threaten human health and the environment. The focus of the Laboratory's research program is on methods and their cost-effectiveness for prevention and control of pollution to air, land, water, and subsurface resources; protection of water quality in public water systems; remediation of contaminated sites, sediments and ground water; prevention and control of indoor air pollution; and restoration of ecosystems. NRMRL collaborates with both public and private sector partners to foster technologies that reduce the cost of compliance and to anticipate emerging problems. NRMRL's research provides solutions to environmental problems by: developing and promoting technologies that protect and improve the environment; advancing scientific and engineering information to support regulatory and policy decisions; and providing the technical support and information transfer to ensure implementation of environmental regulations and strategies at the national, state, and community levels.

This publication has been produced as part of the Laboratory's strategic long-term research plan. It is published and made available by EPA's Office of Research and Development to assist the user community and to link researchers with their clients.

Sally Gutierrez, Director
National Risk Management Research Laboratory

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Acronyms and Abbreviations

Term	Definition
AEO	Annual Energy Outlook
AER	Annual Energy Review
ANOVA	analysis of variance
AQA	air quality assessment
BAU	business as usual
BTU	British thermal units
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CCS	carbon capture and sequestration
CCSP	Climate Change Science Program
CO	carbon monoxide
CO_2	carbon dioxide
Conv Nuc	scenario of relaxed wind constraints and nuclear limited to conventional
DOE	Department of Energy
EIA	Energy Information Administration
ELC	electric
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
EPA9R	EPA 9 region MARKAL database
EPANMD	EPA national model MARKAL database
EPRI	Electric Power Research Institute
FGD	flue gas desulfurization
GDP	gross domestic product
GHG	greenhouse gas
GJ	gigajoules
Gt	giagtonnes
GT-MHR	gas turbine-module helium reactor
GW	gigawatts
H_2	hydrogen
H_2S	hydrogen sulfide
HTGR	high temperature gas-cooled reactor
IEA	International Energy Agency
IGCC	integrated gasification combine cycle
IHM	initial heavy metal, i.e. enriched uranium
IPCC	International Panel on Climate Change
ISA-W	Integrated Systems Analysis Workgroup
kg	kilogram
kt	kilotonnes
kW	kilowatts
kWh	kilowatt hours
LNB	low NO_X burner
LHV	lower heating value
LWR	light water nuclear reactor

MARKAL	MARKet ALlocation energy-systems computer model
MOX	mixed oxide reactor
M	million (mega)
MtCO2	megatonnes of CO_2
MWd	megawatt days
MWe	megawatt electricity
N_2	nitrogen
NETL	National Energy Technology Laboratory
NGA	natural gas
NGA MU	scenario with natural gas price mark up
NGCC	natural gas combined cycle
NGL	natural gas liquids
NO_X	nitrogen oxides
2x Nuc Inv	scenario with nuclear investment costs doubled
O_2	oxygen
O&M	operation and maintenance
ORD	Office of Research and Development
PBMR	pebble bed modular reactor
PC	pulverized coal
PJ	petajoules
PM	particulate matter
PM_{10}	PM with aerodynamic diameter 10 μm or less
$PM_{2.5}$	fine PM with aerodynamic diameter of 2.5 μm or less
PU	plutonium
PUREX	plutonium and uranium extraction
PV	photovoltaics
R2	sum of squared residuals
RES	reference energy system
SCR	selective catalytic reduction
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
TAG	technology assessment guide
Th	thorium
TIHM	tons of initial heavy metal
U	uranium
VOC	volatile organic carbon
yr	year

Executive Summary

The U.S. EPA contributes to the U.S. Climate Change Science Program (CCSP) by working to develop an understanding of the potential human health, ecosystem, and socioeconomic impacts of global change. A central part of this work builds on traditional EPA expertise by examining the connection between climate and air quality. Climate variability will likely result in changes in regional meteorology. These meteorological changes, in turn, may affect air pollution levels by altering atmospheric chemical fate and transport processes as well as biogenic and anthropogenic emissions. To characterize these changes, EPA's Office of Research and Development (ORD) is working on a multiyear Global Change Air Quality Assessment (AQA) to explore the potential consequences of global change on criteria pollutant emissions through midcentury. The research has advanced through a series of projects geared towards building the ability to analyze the relationship between global change and air quality and involves research teams with expertise in meteorological, emissions, and air quality modeling, as well as technology assessment. The research also takes into account demographic, economic, and technological changes that would be expected to occur independent of global change.

EPA's Integrated Systems Analysis Workgroup (ISA-W) contributes to the AQA by crafting scenarios of plausible technology change and assessing how this evolution might impact air pollutant emissions. These activities focus on the two economic sectors that impact air quality the most: transportation and energy (other sectors are considered to capture important system effects). Combined, the sectors account for roughly two-thirds of the pollutants that impact air quality and are areas where significant technological changes are expected to occur over the next several decades. EPA researchers will use the results of ISA-W's technology assessments and corresponding emission growth rates from the scenario analyses to calculate the future emission profiles needed as input to the EPA's air quality models. In 2004, ISA-W produced a report which outlined its approach for technology assessments and provided initial results for the transportation sector. The present technology assessment provides a companion piece focused on electricity generation.

The future of air quality will be controlled by two primary factors: pollutant emissions (influenced by technology use and adoption) and ambient temperature (influenced by climate change). This report presents a series of scenario-driven technology assessments focused the first of these drivers by examining different "classes" of power generation technologies. The assessment investigates the barriers and potential limits to the market penetration through 2030 of both conventional and alternative technologies, and examines the air emission impacts from their use. Information from this assessment will aid the selection of scenarios for inclusion in ORD's 2010 AQA synthesis report.

The report first provides a general overview of EPA's national MARKAL database and energy systems model (EPANMD) and presents results for the business as usual (BAU) baseline scenario. Under baseline assumptions, total electricity use increases 1.3% annually from 13,378 PJ in 2000 to 19,622 PJ in 2030. Annual growth in electricity demand varies between 1.0% in the residential sector, to 2.1% in the commercial and 1.5% in the industrial sectors of the U.S. economy. A total of 293 GW of new electric generation capacity is added between 2000 and 2030 to meet this growth. More than 76% of the new capacity is natural gas technologies, with

61% being natural gas combined cycle and 15% being natural gas combustion turbines. New conventional coal-fired power plants are not added until 2020, though a small amount of integrated gasification combined cycle generation comes on-line in 2015. Renewables add 34 GW of capacity, with 61% coming from wind power generation, 15% from biomass combined cycle, and 14% from geothermal.

Coal-fired power plants continue to generate the most electricity in the BAU scenario. As the emissions constraints in the electric generation sector tighten over time, much of the existing capacity is retrofitted with NO_X and SO_2 controls and 20 GW of new capacity is built. New coal capacity includes FGD for SO_2 and SCR for NO_X and therefore does not need retrofit technologies for emissions controls. Nuclear power capacity increases slightly, but this is due to capacity upgrades at existing facilities; no new nuclear plants are built in the business-as-usual case. Overall, coal electric generation grows 0.5% annually, natural gas grows 3.8%, and renewables grow 2.7%.

The model constrains NO_X and SO_2 starting in 2010 and 2015, respectively, to conform with DOE projections of the impacts from the Clean Air Act regulations. These constraints are binding over the applicable time periods and emissions do not drop below the upper limits. CO_2 emissions in the electric sector grow 1% annually from 689,296 kt in 2000 to 927,302 kt in 2030.

The EPANMD representation of coal plant retrofits is simplified in that it averages emissions over the whole country and ignores regional issues related to air quality. As a result, the retrofit coal capacity is smaller than it actually is (or will be), and when retrofits are selected they tend to be lower cost technologies with lower removal efficiencies. Retrofits for SO_2 control are currently installed on 4.8% of existing coal fired power plants. Tightening of emissions constraints leads to FGD units being installed on over 14% of plants. Low NO_X Burners (LNB) for NO_X control are currently on 80% of existing plants. Over time, SNCR units are added to the existing LNB units for increased emissions reductions. In later years, SCR units play a larger role (SCR would be favored from the start if the EPANMD captured emissions trading).

Sensitivity and uncertainty analyses show that much of the EPANMD electric sector's behavior appears to be influenced by whether specific technologies and fuels meet base or peak load electricity demands. The predominant base load technologies are coal-fired power plants and nuclear power plants. Coal is the most competitive, and has the largest market share. Natural gas- and oil-fueled technologies are used to meet peak electricity demands. Both fuels experience some cross-sector interactions with the transportation sector because natural gas and refined oil products can be used within vehicles. While there was some evidence of cross-sector interactions, these were largely of secondary importance to in-sector technology and fuel competition.

The electric sector emissions constraints have interesting effects on the generation technology mix. When natural gas becomes more expensive and natural gas technology utilization decreases, for instance, use of coal also decreases. This behavior, which may at first seem counter-intuitive, is explained by the system's response to the electric sector NO_X constraint. Since coal technologies had higher NO_X emissions than natural gas technologies, and since NO_X constraints on electricity generation were binding, the model opted to replace natural gas with oil. Oil combustion also leads to greater NO_X emissions than that from natural gas, thought it is less than coal. Oil therefore displaces some coal. This fuel-switching and related technology change had implications on CO_2 emissions as well.

The electric sector NO_X constraint also affects the model's response to increased nuclear capacity. By introducing electricity generation capacity that does not have NO_X emissions, coal-fired power plants are less constrained in meeting the electric sector NO_X constraint. In response, the fraction of coal-fired plants projected to make use of NO_X controls, such as SCR, decreases. The same behavior can be expected from increased electricity generation from low- or zero-NO_X renewables, such as solar or hydropower.

The electricity generation investment hurdle rate has an additional impact on future-year energy sector technologies. Increasing the hurdle rate effectively makes it more difficult for new, efficient technologies to penetrate the electricity generation market. This has the effect of increasing the marginal peak electricity price, increasing CO_2 emissions from electricity generation, and decreasing the penetration of renewables. Thus, addressing hesitancy to adopt new technologies through some approaches for hedging risk may yield a more efficient electricity generation system.

Imports of fossil fuels are correlated with the use of oil in electricity generation, but inversely correlated with natural gas use, reflecting the fact that natural gas demand is largely met by domestic supplies in the model. Cross-sector fuel switching resulting from changes in natural gas and oil consumption in the transportation sector may also have an impact, but further analysis is needed to characterize this behavior.

Finally, changes in system-wide CO_2 emissions in response to variation in model inputs were minor, with decreases of less than 3% observed. This output is influenced by the inability of low-CO_2 emitting technologies, and in particular, renewables, to achieve high market penetrations. When these technologies do penetrate, the potential reductions in CO_2 emissions are often offset by increased use of coal and other fossil fuels, made possible via the room under the NO_X limit created by the renewables.

Moving beyond its detailed sensitivity analysis of BAU results, the assessment focuses on the air quality impacts of two advanced electric sector technologies: nuclear power and carbon capture and sequestration (CCS). The analysis first treats these technologies separately in order to examine their independent impacts on air quality relative to the BAU results; a final series of scenarios allows competition between these advanced technologies and a rudimentary representation of wind power.

The nuclear scenario results offer important insights into the role that this family of technologies can play in the U.S. electricity system over the next three decades. Increased natural gas and coal prices, for instance, do not have a significant impact on the penetration of new nuclear units. As a result, nuclear power only provides a modestly effective hedge against high fossil fuel prices in the electric sector, at least over the fuel price ranges explored here.

Though modest, these nuclear technology penetration levels contribute to meeting the electric sector's CAA limits for SO_2 and NO_X. Nuclear generation, however, has a limited impact on system-wide carbon emissions. When the electric sector follows an arbitrary reduced carbon emissions trajectory, nuclear capacity plays a more significant role and leads to SO_2 and NO_X reductions below CAA constraints.

Although all nuclear technology options are economical, the model prefers advanced high temperature gas-cooled reactors (HTGRs) to conventional designs such as light water and mixed-oxide reactors. The issues governing this preference include whether HTGR developers can meet the model's optimistic nth-of-a-kind cost assumptions and how rapidly units can be manufactured and deployed over the next few decades.

The assessment also approaches CCS from a combined technology adoption and air quality perspective. The EPANMD's energy systems framework is important in this analysis as CCS would compete with measures to reduce the carbon intensity of power production and efforts to improve end-use efficiency. Driven by an arbitrary electric sector CO_2 trajectory, for instance, the model relies on coal-to-gas fuel-switching as much as it does on CCS. The model adopts CCS mainly for baseload generation in the form of new IGCC capture capacity. CO_2 capture retrofits are not an economically attractive option as retrofit capacity incurs a significant energy penalty. Only when this penalty is reduced does retrofit capacity generate a significant share of the electric sector's output; model results are less sensitive to retrofit technology costs. Like the nuclear power analysis, moderate levels of CCS adoption do not significantly affect electric sector criteria pollutant emissions. CCS displaces new (conventional) baseload capacity when the electric sector follows a non-BAU carbon trajectory, but this adoption does not significantly impact the operation of existing coal-fired plants, which contribute most of the sector's CAA constrained SO_2 and NO_X emissions.

Several key results emerge from an integrated assessment of nuclear, CCS, and wind power. First, the penetration of advanced electric sector technologies does not necessarily yield a significant criteria pollutant benefit. Under all but the most radical departures from BAU electric sector carbon trajectories, for instance, nuclear power and CCS merely replace the new coal and gas capacity that are needed to meet increasing electricity demand. The model maintains its existing coal plants through their useful lifetime, and criteria pollutant emissions remain near their CAA limits as a result. This picture changes when electric sector carbon emissions depart furthest from their BAU levels and CO_2 emissions from baseload plants declines. Even in these cases, however, the decrease in NO_X emissions is more modest than that seen in SO_2.

Second, CCS is dominated by investment in new nuclear technologies as well as additional gas-fired generation and wind power. Only when favorable CCS cost and efficiency assumption combine with high nuclear investment cost and gas price scenarios does CCS approach its modeled growth constraints over the full time horizon in which it is available (2015-2030). Furthermore, given that CO_2 capture and geologic sequestration are both untested at even the modest scales adopted here, the model results are probably optimistic.

Finally, even with a rudimentary conception of wind resources, wind generation in the EPANMD competes for a significant share of electric power output when the model incorporates more favorable growth constraint assumptions for new turbine investment. These growth limits are modest compared to some predictions, though a more realistic representation of wind turbine dispatch is needed to capture the technology's intermittency and evaluate its actual potential.

While the model results provide insight into future energy technology pathways, they are nonetheless based on a model, and all models have limitations that introduce caveats. The use of national rather than regional inputs to MARKAL is perhaps the most significant limitation affecting the analysis. The EPANMD is a national database that does not contain region-specific data. The lack of regional data manifests itself in three key limitations. First, important regional differences in resource supplies, energy service demands, and technology availability cannot be represented. Second, the EPANMD does not include transportation costs for coal or other resources. Third, air pollution regulations that have been implemented on a state or regional level must be modeled at a national level within EPANMD. ISA-W is currently developing a 9-region MARKAL database that will account for variations in these factors. Beyond its lack of region-specific detail, the EPANMD does not model unit dispatch, and contains a very generic representation of the existing fleet of U.S. coal-fired power plants. Equally important, the analysis excludes consideration of efficiency improvements as well as non-traditional generating technologies which could supply a large share of the nation's electricity in the coming decades. Likewise, the analysis does not consider the impact of radical technological innovation, such as the emergence of "nano-bio-info" technologies, on future energy demand.

Section 1

Electricity Generation and Air Quality

The U.S. EPA contributes to the U.S. Climate Change Science Program (CCSP) by working to develop an understanding of the potential human health, ecosystem, and socioeconomic impacts of global change. A central part of this work builds on traditional EPA expertise by examining the connection between climate and air quality. Climate variability will likely result in changes in regional meteorology. These meteorological changes, in turn, may affect air pollution levels by altering atmospheric chemical fate and transport processes as well as biogenic and anthropogenic emissions. To characterize these changes, EPA's Office of Research and Development (ORD) is working on a multiyear Global Change Air Quality Assessment (AQA) to explore the potential consequences of global change on criteria pollutant emissions through midcentury. The research has advanced through a series of projects geared towards building the ability to analyze the relationship between global change and air quality and involves research teams with expertise in meteorological, emissions, and air quality modeling, as well as technology assessment. The research also takes into account demographic, economic, and technological changes that would be expected to occur independent of global change.

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1.1 Electricity Production and Demand

Reliable access to electricity is fundamental to economic productivity, quality of life, and the comforts of daily existence. Since its development in 1882 as a power source to operate 800 of Thomas Edison's electric light bulbs (Edison Electric Institute, 2006), the U.S. electric power generating capacity has increased to over 1,051,000 megawatts. Electricity is now the primary power source for most commercial and residential building end-use services, including lighting, space heating and cooling, water heating, ventilation, and refrigeration. The technologies on which the information economy rest are also dependent on electricity, and more traditional manufacturing industries like chemical and paper production remain major consumers of electric power.

Demand for electricity has a strong historical linkage to the development of the U.S. economy. Figure 1.1 illustrates the relationship between annual change in electricity use and annual growth rate of Gross Domestic Product (GDP) for the past 55 years. Over this period, the energy used to produce electricity climbed from about 5,300 PJ in 1950 to almost 42,100 PJ in 2005 (EIA, 2005b). As a result, the relative energy intensity of the economy doubled between 1950 and 1977 (see Figure 1.1). While both electricity use and GDP have continued to grow, energy intensity has declined by 33% since its mid-1970s peak (BEA, 2006; EIA, 2005b). Improvements in end-use energy efficiency and the shift from a manufacturing- to a service-based economy are largely responsible for this decline.

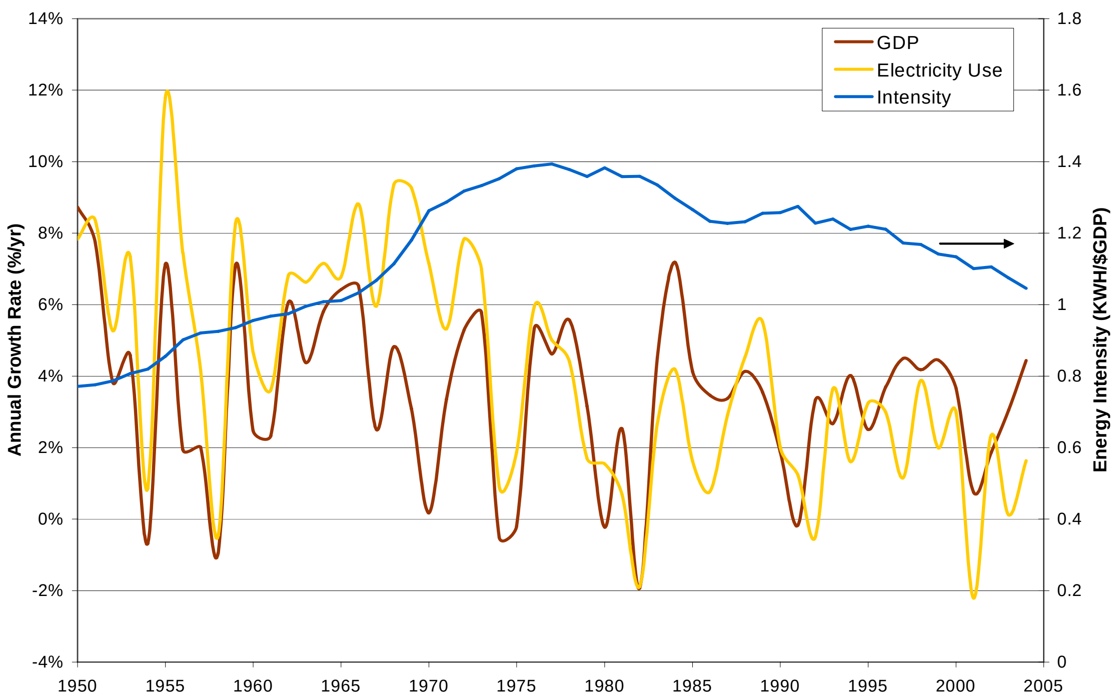

Figure 1.1: Energy Intensity and Growth Rate Trends for U.S. GDP and Electricity Use; Sources: BEA (2006), EIA (2005b)

A variety of fuels serve as primary energy sources for U.S. electricity production, as Figure 1.2 illustrates (EIA, 2005b). Coal, which is abundant in the U.S. has dominated electricity production and currently accounts for 50% of U.S. generation. Oil was an important source until the 1970's when U.S. production began declining and the Arab oil embargo caused import shortages. Oil now fuels 3% of electricity generation. Natural gas use increased by nearly half during the 1990s, though more recent volatility and sustained high prices are discouraging expanded use.

Fuel choice for electricity generation is also regionally dependent (Edison Electric Institute, 2006b). In both the West and East North Central census regions, coal is the dominant energy fuel for electricity production, with generating shares of 77% and 70% respectively. In New England, natural gas dominates at 38%. Hydroelectric dominates in the contiguous Pacific region at 41%; and oil, at 52%, dominates in the noncontiguous Pacific. In the Middle Atlantic region, nuclear and coal account for 35% and 36%, respectively.

Demand for electricity is governed by the end-use energy services of the other sectors of the economy: residential, commercial, industrial, and transportation. Figure 1.3 shows the distribution of electricity use across these sectors for the U.S. in 2004. Residential and commercial demand each account for about one-third of electricity use, while industrial, including non-utility direct usage, accounts for another 30%. The U.S. transportation infrastructure, in contrast, relies on a negligible amount of electricity. Demand for end-use services (lighting, cooling, manufacturing, etc.) will increase further as the economy and population expand. Projections show the U.S. GDP growing by 2.9 to 3.0% annually over the next 25 years (EIA, 2006c) while the U.S. population expands by 29% (U.S. Census Bureau, 2006). This growth will impact electricity demand and potentially air quality.

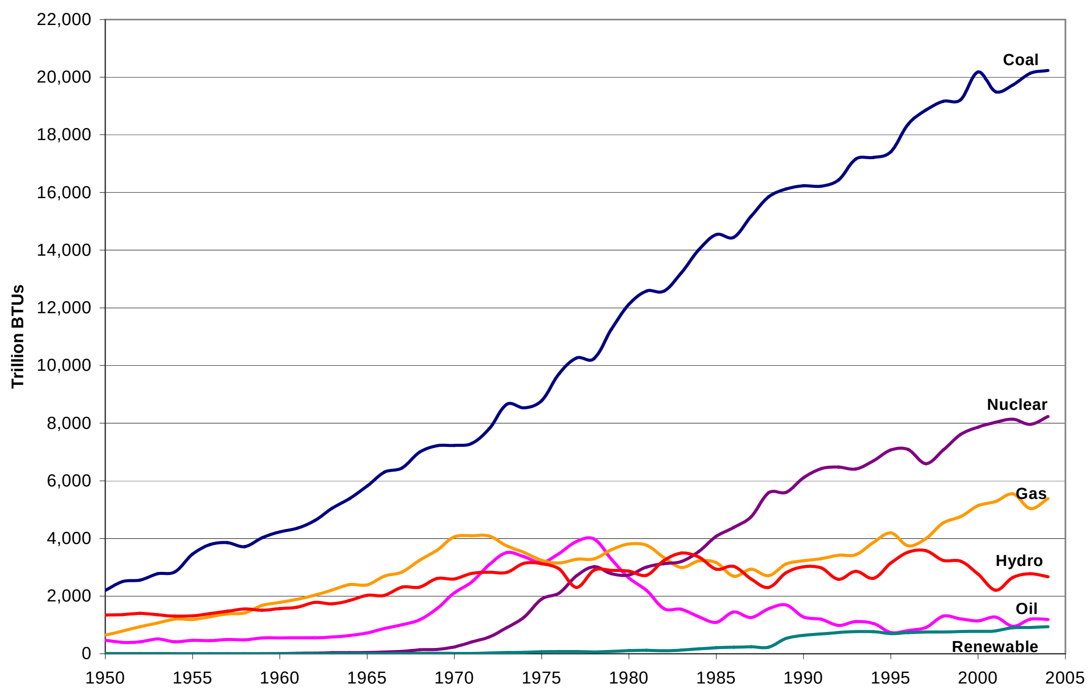

Figure 1.2: Fuel Sources for U.S. Electricity Generation; Source: EIA (2005b)

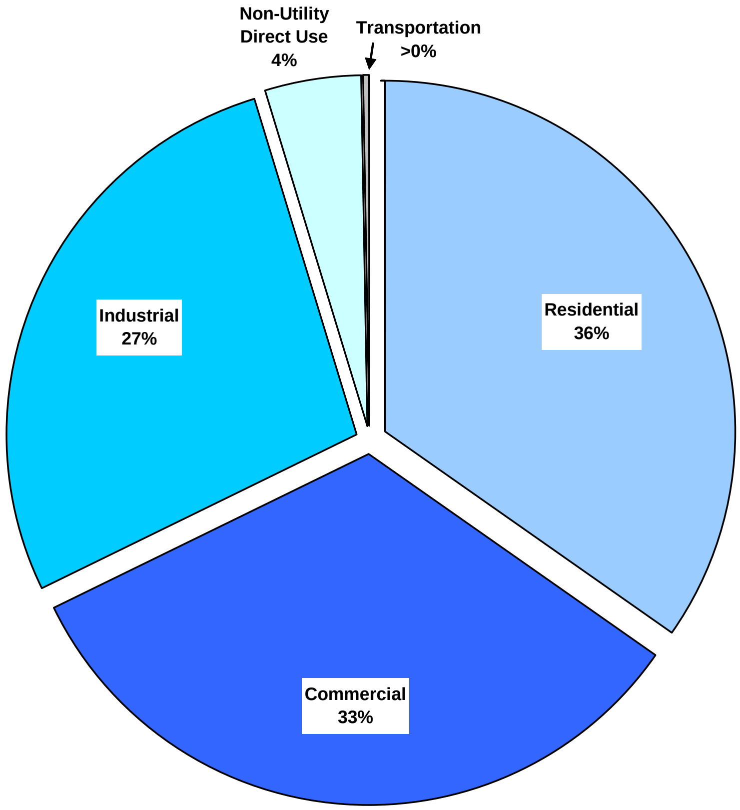

Figure 1.3: U.S. Distribution of Electricity Usage in 2004; Source: EIA (2005b)

1.2 Electricity and Air Quality

Electricity is produced primarily from the combustion of fossil fuels. It is this combustion process which causes the production and release of a variety of atmospheric pollutants, including SO_2, NO_X, particulates, CO_2, and mercury (U.S. EPA, 2005, 2006a, and 2006b). All of these pollutants impact human health and the environment. Table 1 shows the percent of total pollutant emissions which are produced from electricity generating technologies. SO_2 and NO_X (which contribute to acid rain) can also contribute to $PM_{2.5}$ and ozone formation, respectively, further degrading ambient air quality.

Table 1.1: Percent of Total Emissions from U.S. Electric Generation Technologies; Sources: U.S. EPA (2005), (2006a), and (2006b)

Impact	Ambient Air Quality				Toxic	Climate Change	
	---------		Acid Rain				
Pollutant	PM_{10}	$PM_{2.5}$	SO_2	NO_X	Hg	CO_2	N_2O
Emission %	16	3	65	20	43	38	4

EPA has developed regulations for several of these pollutants which have already produced significant emission reductions. The Acid Rain Program of the Clean Air Act (CAA) of 1990, for instance, regulates SO_2 and NO_X from electric generation. This program entered Phase II of the reduction requirements in 2000. By 2010, SO_2 emissions from power plants will be capped at 8.95 million tons per year, a reduction of more than half from 1980 emission levels. After implementation of Phase II, NO_X emissions from power plants have declined by a total of 2.1 million tons/year from 1980 levels. In addition to the Acid Rain Program, SO_2 and NO_X emissions are affected by the Clean Air Interstate Rule of 2005 which impacts 28 Eastern states and the District of Columbia. The Phase II caps for SO_2 and NO_X in 2015 will be 2.5 and 2.2 million tons, respectively.

How these caps will be met and maintained under growing demand for electricity is yet to be determined. Options include pre- or post-combustion control of emissions from fossil fuel sources, finding "cleaner" technologies for producing electricity, or implementing efficiency improvements on both supply and demand.

1.3 Technology Assessment, Scenario Analysis, and the Use of MARKAL

Technology assessment lies at the core of ISA-W's electric sector analysis. Such assessments are multidimensional in that they require a detailed characterization of individual technologies as well as the economic and institutional factors that both drive and constrain their use. Resource supply costs, demand estimates for energy-related services, emission considerations, and other drivers, for instance, combine to determine how existing and new technologies compete. Data for these assessments comes primarily from government agencies, academic studies, other published literature, industry studies, and individual consultations. Mid-range or consensus estimates furnish the starting point for inputs to the typical assessment, though sensitivity analyses examine the effects of more divergent assumptions.

A systems perspective is needed to capture the interaction of the diverse factors required by a complete technology assessment. Such a perspective goes beyond lifecycle assessment's "cradle-to-grave" analysis of resource needs and environmental impacts for a given technology to examine how multiple technologies compete with each other to meet demand, and how resource constraints affect this balance. A systems focus, therefore, captures both direct environmental impacts (e.g., the emissions generated by a particular technology) as well as indirect effects (e.g., how reducing demand for a fuel in one economic sector might lower its cost and consequently increase its use—and associated emissions—in another). These indirect feedbacks can be counterintuitive, and a systems perspective, therefore, helps capture unanticipated consequences. In addition, real-world trade-offs in technological and economic feasibility often emerge only at the systems level, an example being that of a high capital cost technology (e.g., a coal-fired power plant) that only makes sense to build if its use is sufficient to recover the initial investment.

Technology assessment within a systems framework provides the structure for ISA-W's research. The use of scenarios guides the actual analysis of technological futures and assists in understanding how complex systems may evolve. Scenarios are internally consistent depictions of how the future may unfold, given assumptions about economic, social, political, and technological developments as well as consumer preferences (Schwartz, 1996). Scenarios explore plausible futures by using a model or models to generate an outcome (or set of alternative outcomes) consistent with a set of motivating assumptions, sometimes called a “storyline.” It is important to stress that these consequences should not be interpreted as predictions, for example, about levels of new technology market penetration or emission trajectories. Rather, the technology parameters and economic data used as inputs are best seen as starting-point assumptions that reflect a range of reasonable estimates.

Scenario analysis aims to examine how changes in model parameters (inputs) affect outputs across sets of related storylines, rather than focus on the results from a particular scenario. No attempt is made to consider every possible future. These comparative analyses alternately look forward (“What-if?”) to examine how competing sets of input assumptions drive technology adoption and emissions, and backward (“How-could?”) to identify the energy technology pathways available to meet some future environmental or technological goal. Scenarios, therefore, facilitate assessment of the consequences of varying assumptions, the range of possible futures, and trade-offs and branch points that govern choices among these futures. Results from a selected set of scenarios will serve as input to the ORD Air Quality Assessment.

In order to investigate scenarios of future electric generation technologies and their impact on future air pollutant emissions, ISA-W adopted the MARKAL energy-systems modeling framework (see Shay et al. 2006). The Department of Energy’s Brookhaven National Laboratory created MARKAL (short for MARket ALlocation) in the late 1970s, and a strong international users group has organized itself to support continuing applications and extensions. MARKAL maps the energy economy from primary energy sources through their refining and transformation processes to the point at which a variety of technologies (e.g., classes of light-duty personal vehicles, heat pumps, or gas furnaces) service end-use energy demands (e.g., projected vehicle miles traveled, space heating). All economic sectors—industrial, residential, commercial, and transportation—are covered. A large linear programming model, ISA-W’s MARKAL model, determines the least-cost pattern of technology investment and utilization required to meet specified demands and model constraints and then calculates the resulting criteria pollutant and greenhouse gas emissions.

MARKAL’s strength lies in the fact that it is a systems model. The energy system is complex and interactions must be considered, but feedbacks are not always intuitive; reducing demand for a fuel in one economic sector, for instance, might lower its cost and, therefore, increase its use in another. Such real-world trade-offs in technological and economic feasibility often emerge only at the systems level. In addition, the readiness, costs, and performance of individual energy technologies (e.g., wind turbines) must be considered in the full socio-economic context of their use. MARKAL quantifies the system-wide effects of changes in resource supply and use, technology availability, and environmental policy.

MARKAL is a data-driven energy-economic model. The user specifies the energy system structure, including resource supplies, energy conversion technologies, end-use energy service demands, and the technologies needed to satisfy these demands. The user must also provide data to characterize individual technologies and resources, including their fixed and variable costs, availability, performance attributes, and pollutant emissions. MARKAL is data-intensive. Within the electric power sector, for instance, ISA-W’s MARKAL database contains 24 generating technology options (both existing and future vintages). The database is divided into five-year periods that stretch from 1995 to 2035. The time horizon will be extended to 2055 in future work to meet AQA needs.

Finally, ISA-W has also developed a suite of analytical and visual tools for evaluating sensitivity to uncertainties in model parameters and inputs and exploring the solution space. Assessing the sensitivity of results to assumptions is an important part of any scenario analysis. Do the results, for instance, depend on a narrow range of input parameters? Or do several technology pathways lead to equivalent outcomes? Confidence in model results depends on answering such questions, and these answers may also have important policy implications.

1.4 Overview of the Electric Sector Technology Assessment

The future of air quality will be controlled by two primary factors: pollutant emissions (influenced by technology use and adoption) and ambient temperature (influenced by climate change). This report presents a series of technology assessments focused the first of these drivers by examining different "classes" of power generation technologies. The assessment investigates the barriers and potential limits to the market penetration through 2030 of both conventional and alternative technologies, and examines the air emission impacts from their use. Information from this assessment will aid the selection of scenarios for inclusion in ORD's 2010 AQA synthesis report.

The following section provides a general overview of EPA's MARKAL model and presents results for the business as usual (BAU) baseline scenario. Section 3 examines the factors driving BAU results through an extended sensitivity analysis. The following two sections focus on advanced generation technologies by investigating the air quality impacts of nuclear power (Section 4) and carbon capture and sequestration (Section 5). The analyses treat these two technologies separately in order to examine their independent impact on air quality relative to the BAU results. Section 6 then presents a series of scenarios which allow competition between these advanced technologies and a rudimentary representation of wind power. Finally, Section 7 discusses the assessment's limitations and outlines future work.

Section 2
EPA National Model Baseline

The Electric Generation Sector in the EPA National MARKAL Database (EPANMD) characterizes existing and new technologies available electricity generation. Based on sector-specific electricity demand (residential, commercial, industrial, and transportation), fuel prices, technology costs, and the environmental and operational constraints incorporated in the model, MARKAL determines the least cost way to meet system electricity demand. This section describes the EPANMD's representation of electric power generation technologies and presents the baseline, or business as usual (BAU), model results. Shay et al. (2006) provides a complete description of the EPANMD.

MARKAL is structured around a Reference Energy System (RES), a network diagram that depicts an energy system from resource supply to end-use consumption. The RES divides an energy system up into a series of elements, including primary energy resources plus process, conversion, and demand technologies. These technologies feed into a final stage consisting of end-use demands for useful energy services. End-use demands include items such as residential lighting, commercial space conditioning, and automobile passenger miles traveled. Energy carriers interconnect the stages. A large linear programming model, MARKAL determines the least-cost means of meeting end-use demand over the model's time horizon, 1995-2030. (For a detailed description of MARKAL, see ETSAP, 2004).

The electric generation sector specific RES consists of imported electricity resource technologies and conversion technologies (e.g., existing coal steam) which output electricity to the system. "Dummy" emissions process technologies, which have no costs, track emissions through the system. Figure 2.1 provides a generic representation of the electric sector RES structure.

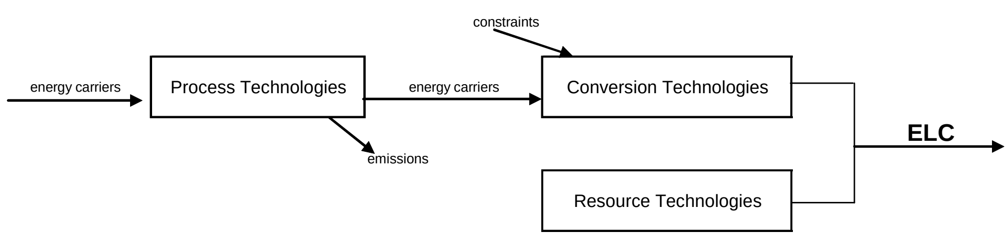

Figure 2.1: Generic Electric Sector RES

2.1 Technology Characterization

The EPANMD contains twenty-four electric generation technologies, sixteen of which have existing capacity in the U.S. For a complete description of the model's technology representation, see Shay et al. (2006). EPANMD is calibrated to the 2002 Annual Energy Outlook (EIA, 2002a), except where noted.

Available Technologies
Table 2.1 lists the existing electric generation technologies represented in the EPANMD with their initial capacities. Note that the EPANMD does not explicitly model the costs associated with retiring these technologies.

Table 2.1: Existing Electric Generation Technologies

Technology	GW Existing Capacity (1995)
Coal Steam Plants	307.8
Natural Gas Steam Turbine	115.0
Conventional Nuclear LWR	102.0
Conventional Hydropower	78.5
Natural Gas Combustion Turbine	31.7
Diesel Combustion Turbine	25.2
Hydropower Pumped Storage	22.0
Residual Fuel Oil Steam	17.0
Natural Gas Combined Cycle	13.6
Biomass Combined Cycle	7.6
Diesel Internal Combustion Engine	3.5
Municipal Solid Waste	3.4
Geothermal	3.0
Wind Central Electric	1.7
Solar Central Thermal	0.3
Solar Photovoltaic	0.1

New Technologies
The new electric generation technologies available to the model in the base case include:

- Advanced Coal—Integrated Gasification Combined Cycle (IGCC)
- Advanced Coal—Pressurized Fluidized Bed
- Advanced Natural Gas Combined Cycle
- Advanced Natural Gas Combustion Turbine
- Distributive Generation—Baseload
- Distributive Generation—Peak

Technologies are characterized in the model by costs (investment, operation, and maintenance), efficiencies, lifetimes, emissions, hurdle rates, fractions in peak equations, and availability. Hurdle rates refer to discount rates applied to the investment costs of new technologies which are meant to mimic hesitancy on the part of the purchaser to invest in a newer technology over an established technology. The fraction in peak equations refers to the fraction of the technology's total capacity in a specified period which can be counted on to be available to meet peak demand and reserve margin requirements. Availability refers to the percentage of the year that a technology is on-line and available accounting for forced and scheduled outages.

The database draws from five primary data sources, which are listed below in order of precedence.

1. *Annual Energy Outlook 2002* (EIA, 2002a)
2. “Supporting Analysis for the Comprehensive Electricity Competition Act” (DOE, 1999)
3. *Technical Assessment Guide* (EPRI, 1993)
4. 1997 DOE MARKAL database (Tseng, 2001)
5. National Energy Technology Laboratory (NETL) (Boilanger, 2002)

Tables 2.2 and 2.3 list the main parameters and their values for the available technologies. All values are in model base year (1995) dollars; post-2010 values remain constant.

In addition to the costs of each electric generation technology, all electricity generated by the sector (except that from distributed generation) is subject to the transmission and distribution costs shown in Table 2.4.

2.2 Model Constraints

Several constraints are active during the baseline run, including:

1. A 30% reserve capacity (the amount by which the installed electricity generating capacity exceeds the average load of the season and time-of-day division of peak demand).
2. A hurdle rate of 18% (applied to all new generation technologies).
3. Nuclear capacity bound set at 2005 AEO levels (EIA, 2005a).
4. IGCC investment in IGCC limited to the 2002 AEO projections (EIA, 2002a).
5. Investment in renewables fixed at levels based on analysis by in-house researchers and 2005 AEO (EIA, 2005a) estimates (see Table 2.5).

Table 2.2: Electricity Generation Technologies and Associated Cost Parameters

Technology Name	Heat Rate (BTU/kWh)	Capital Costs (1995 million $/kW)	Variable O&M Costs (1995 million $/kW)	Fixed O&M Costs (1995 million $/kW)
Existing Coal Steam	11990	n/a	2.78	14.21
Coal Steam – 2000	9419	1119	3.10	21.48
Coal Steam – 2005	9253	1110	3.10	21.48
Coal Steam – 2010	9087	1083	3.10	21.48
Integrated Coal Gasif. Combined Cycle -- 2000	7969	1338	0.73	29.98
Integrated Coal Gasif. Combined Cycle -- 2005	7469	1315	0.73	29.98
Integrated Coal Gasif. Combined Cycle -- 2010	6968	1287	0.73	29.98
Pressurized Fluidized Bed	9228	1570	3.10	38.11
Coal Gasification Molten Carb Fuel Cell	7575	2683	24.83	34.49
Distributed Generation--Base--2005	10991	623	13.87	3.69
Distributed Generation--Base--2010	9210	623	13.87	3.69
Distributed Generation--Peak	10620	559	21.20	11.53
Existing Natural Gas Combined Cycle	8030	434	0.48	14.31
Natural Gas Combined Cycle--2000	7687	456	0.48	14.33
Natural Gas Combined Cycle--2005	7343	453	0.48	14.33
Natural Gas Combined Cycle--2010	7000	448	0.48	14.33
Natural Gas Advanced Combined Cycle--2005	6639	572	0.48	13.27
Natural Gas Advanced Combined Cycle--2010	6350	526	0.48	13.27
Natural Gas Steam	9500	959	0.48	28.61
Existing Natural Gas Combustion Turbine	11900	322	0.09	5.91
Natural Gas Combustion Turbine--2000	11467	339	0.09	5.92
Natural Gas Combustion Turbine--2005	11033	336	0.09	5.92
Natural Gas Combustion Turbine--2010	10600	333	0.09	5.92
Natural Gas Advanced Combustion Turbine--2005	8567	446	0.09	8.41
Natural Gas Advanced Combustion Turbine--2010	8000	384	0.09	8.41
Conventional Nuclear	10800	3445	0.29	77.05
Diesel internal combustion engine	13648	376	8.07	0.78
Residual Fuel Oil Steam	9500	959	0.48	28.61
Distillate Oil Combustion Turbine	11900	322	0.09	5.91
Hydroelectric Pumped Storage	10280	1615	2.40	15.18
Biomass Gasification Combined Cycle	8911	1725	2.66	41.25
Geothermal Binary Cycle and Flashed Steam	32173	1746	0.00	64.31
Hydroelectric	10280	929	4.07	12.90
Municipal Solid Waste-Landfill Gas	13648	1429	0.01	88.39
Solar Central Thermal	10280	2539	0.00	43.93
Central Photovoltaic	10280	3830	0.00	9.04
Photovoltaic--Residential	10280	7519	0.00	118.28
Local Wind Turbine	10263	1246	7.45	8.51
Wind Central Electric	10280	982	0.00	23.44

Table 2.3: Lifetime and Availability Parameters for Electricity Generation Technologies

Technology Name	Technical Lifetime (years)	Availability Fraction	Fraction* of unavailability that is forced	Fraction of Capacity for Peak and Reserve
Existing Coal Steam	40	0.85	0.37	0.96
Coal Steam – 2000	40	0.85	0.37	0.96
Coal Steam – 2005	40	0.85	0.37	0.96
Coal Steam – 2010	40	0.85	0.37	0.96
Integrated Coal Gasif. Combined Cycle -- 2000	30	0.85	0.37	0.90
Integrated Coal Gasif. Combined Cycle -- 2005	30	0.85	0.37	0.90
Integrated Coal Gasif. Combined Cycle -- 2010	30	0.85	0.37	0.90
Pressurized Fluidized Bed	40	0.85	0.50	0.80
Coal Gasification Molten Carb Fuel Cell	30	0.87	0.80	0.60
Distributed Generation--Base--2005	30	0.84	0.63	0.96
Distributed Generation--Base--2010	30	0.84	0.63	0.96
Distributed Generation--Peak	30	0.84	0.63	0.96
Existing Natural Gas Combined Cycle	30	0.91	0.57	1.00
Natural Gas Combined Cycle--2000	30	0.91	0.57	0.94
Natural Gas Combined Cycle--2005	30	0.91	0.57	0.94
Natural Gas Combined Cycle--2010	30	0.91	0.57	0.94
Natural Gas Advanced Combined Cycle--2005	30	0.91	0.57	0.86
Natural Gas Advanced Combined Cycle--2010	30	0.91	0.57	0.86
Natural Gas Steam	40	0.85	0.37	0.96
Existing Natural Gas Combustion Turbine	30	0.92	0.47	0.96
Natural Gas Combustion Turbine--2000	30	0.92	0.47	0.96
Natural Gas Combustion Turbine--2005	30	0.92	0.47	0.96
Natural Gas Combustion Turbine--2010	30	0.92	0.47	0.96
Natural Gas Advanced Combustion Turbine--2005	30	0.92	0.47	0.94
Natural Gas Advanced Combustion Turbine--2010	30	0.92	0.47	0.94
Conventional Nuclear	40	0.80	0.42	0.85
Diesel internal combustion engine	20	0.84	0.63	0.96
Residual Fuel Oil Steam	40	0.85	0.37	0.98
Distillate Oil Combustion Turbine	30	0.92	0.47	0.96
Hydroelectric Pumped Storage	50	varies by timeslice	n/a	0.95
Biomass Gasification Combined Cycle	30	0.80	0.80	0.84
Geothermal Binary Cycle and Flashed Steam	30	0.64	1.00	0.63
Hydroelectric	60	0.44	0.10	0.94
Municipal Solid Waste-Landfill Gas	30	varies by timeslice	n/a	0.90
Solar Central Thermal	30	varies by timeslice	n/a	0.30
Central Photovoltaic	30	varies by timeslice	n/a	0.50
Photovoltaic--Residential	20	varies by timeslice	n/a	0.30
Local Wind Turbine	20	varies by timeslice	n/a	0.30
Wind Central Electric	30	varies by timeslice	n/a	0.30

*This fraction is applied to (1- availability fraction).

Table 2.4: Electricity Transmission and Distribution Costs

Transmission Investment Cost	228.75	million U.S. $ per GW
Transmission O&M Cost	0.1	million U.S. $ per PJ
Distribution Investment Cost	496	million U.S. $ per GW
Distribution O&M Cost	0.736	million U.S. $ per PJ
Transmission Efficiency	93.5	%

Table 2.5: Total Allowed Generating Capacity of Renewable Technologies in GW

Technology	2000	2005	2010	2015	2020	2025	2030
Biomass Combined Cycle	7.6	8.3	9.0	9.8	10.7	11.7	12.7
Municipal Solid Waste	3.4	3.8	4.2	4.6	5.2	5.7	6.4
Geothermal	3.0	3.5	4.1	4.8	5.6	6.6	7.7
Hydropower	79.3	79.3	79.3	79.3	79.3	79.3	79.3
Solar Central Photovoltaic	0.1	0.2	0.2	0.4	0.6	0.8	1.3
Solar Photovoltaic - Residential	0.1	0.2	0.2	0.4	0.6	0.8	1.3
Wind Central Electric	2.5	9.1	11.0	13.2	15.8	19.0	22.8

Emissions Constraints and the Coal Steam Retrofits

The Clean Air Act (CAA) imposes emissions constraints on SO_2 and NO_X emissions from the electric power sector. In order to keep model results in line with these emissions levels, constraints on SO_2 and NO_X in the electric sector were developed from DOE projections and applied in the model (Table 2.6). These constraints reflect future emissions under the existing trading schemes, though MARKAL does not model these trading dynamics internally. Note that the current EPANMD does not represent mercury emissions; future database revisions will add the necessary emission coefficients and control technologies.

Table 2.6 Electric Sector NO_X and SO_2 Emission Constraints in the EPANMD

Emission (kt/PJ)	2000	2005	2010	2015	2020	2025	2030
NOx emissions in the Electric Sector	5875	5300	3500	3500	3500	3500	3500
SO2 emissions in the Electric Sector	11400	10500	9900	9000	9000	9000	9000

The technology-specific CO_2 emission factors used in EPANMD (Table 2.7) were derived from Table A-15 of the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001. SO_2 and NO_X factors were taken from the 1997 DOE MARKAL database with updates (EIA, 2004; OAR, 2002).

Table 2.7: Emission Factors for CO_2 and SO_2 and NO_X in the EPANMD; see Shay et al. (2006) for details.

	Carbon (kT/PJ) Carbon (mT/PJ)	NOx (kT/PJ)	
		Existing Controls	Improved Controls
Coal Steam Plants	25.2	0.0215	n/a
Advanced Coal Plants	25.2	0.043	n/a
Natural Gas Steam Turbine	15.2	0.1075	0.0108
Natural Gas Combustion Turbine and Combined Cycle	15.2	0.043	0.0043
Diesel Combustion Turbine	19.7	0.1075	0.0108
Residual Fuel Oil Steam	21.2	0.1075	0.0108

		SO2 (kT/PJ)		
		High Sulfur	Medium Sulfur	Low Sulfur
Coal Steam Plants	Bit	0.231	0.09	0.046
	Lignite	0.179	0.098	0.04
	Sub-Bit	n/a	0.071	0.033
Advanced Coal Plants	Bit	4.62	1.8	0.92
	Lignite	3.4	1.96	0.8
	Sub-Bit	n/a	1.42	0.66
		Existing Controls	Improved Controls	
Diesel Combustion Turbine		0.024	n/a	
Residual Fuel Oil Steam		0.492	0.024	

Bit = bituminous

Existing Steam Electric Retrofit Technologies

Coal plants account for roughly 41% of total installed U.S. electric generation capacity in 1995 and produce most of the electric sector's SO_2 and NO_X emissions. A proper characterization of the amount of coal capacity with pre-existing controls as well as the cost and removal efficiency of new control retrofits is therefore important to the model's overall performance (Table 2.8).

The EPANMD contains three coal types: bituminous, sub-bituminous, and lignite as well as three sulfur levels: high, medium, and low. Flue gas desulfurization (FGD) costs and efficiencies reflect the fact that FGD performance varies by both coal type and sulfur level. Because NO_X emissions are insensitive to sulfur level, the EPANMD includes three unique NO_X control processes (one for each coal type). The following NO_X control processes are available to the model:

- LNB (Low NO_X Burner)
- SCR (Selective Catalytic Reduction)
- SNCR (Selective Non-Catalytic Reduction)
- LNB-SCR combination
- LNB-SNCR combination

Note that SCR and SNCR can be installed by themselves, at the same time as LNB, or after LNB controls are in place.

Table 2.8: Emission Control Retrofit Data

SO_2 Control Summary

Bituminous	High Sulfur		Medium Sulfur		Low Sulfur	
	FGD	No Retrofit	FGD	No Retrofit	FGD	No Retrofit
2000 Residual Capacity (PJ/yr)	3160		1313		1093	
Equilibrium Emissions Rate (kT/PJ)	0.1186	2.3723	0.0440	1.0536	0.0148	0.2950

Sub-Bituminous	High Sulfur		Medium Sulfur		Low Sulfur	
	FGD	No Retrofit	FGD	No Retrofit	FGD	No Retrofit
2000 Residual Capacity (PJ/yr)	N/A		1684		1718	
Equilibrium Emissions Rate (kT/PJ)	N/A	N/A	0.0360	0.7182	0.0208	0.4144

Lignite	High Sulfur		Medium Sulfur	
	FGD	No Retrofit	FGD	No Retrofit
2000 Residual Capacity (PJ/yr)	149		1047	
Equilibrium Emissions Rate (kT/PJ)	0.0966	1.9294	0.0666	1.3356

NO_X Control Summary

Bituminous	Pass Through	LNB	SCR (after LNB)	SNCR (after LNB)	SCR only	SNCR	LNB-SCR	LNB-SNCR
2000 Residual Capacity (PJ/yr)		15,600						
Equilibrium Emissions Rate (kT/PJ)	0.3464	0.2300	0.0477	0.1194	0.0767	0.1916	0.0460	0.1150

Sub-Bituminous	Pass Through	LNB	SCR (after LNB)	SNCR (after LNB)	SCR only	SNCR	LNB-SCR	LNB-SNCR
2000 Residual Capacity (PJ/yr)		3600						
Equilibrium Emissions Rate (kT/PJ)	0.3511	0.2080	0.0307	0.0766	0.0693	0.1733	0.0416	0.1040

Lignite	Pass Through	LNB	SCR (after LNB)	SNCR (after LNB)	SCR only	SNCR	LNB-SCR	LNB-SNCR
2000 Residual Capacity (PJ/yr)		470						
Equilibrium Emissions Rate (kT/PJ)	0.2006	0.1284	0.0392	0.0981	0.0428	0.1070	0.0257	0.0642

For a complete description of the EPANMD retrofit technology methodology, see Shay et al. (2006).

2.3 Baseline Results

The baseline (or BAU) results presented in this section are MARKAL results generated running the baseline scenario of the EPANMD and cover 1995 (the base year) to 2030.

Electric Generation

Total electricity use increases 1.3% annually from 13,378 PJ in 2000 to 19,622 PJ in 2030 (Figure 2.2). Annual growth in electricity demand varies between 1.0% in the residential sector, to 2.1% in the commercial and 1.5% in the industrial sectors of the U.S. economy (Figure 2.3).

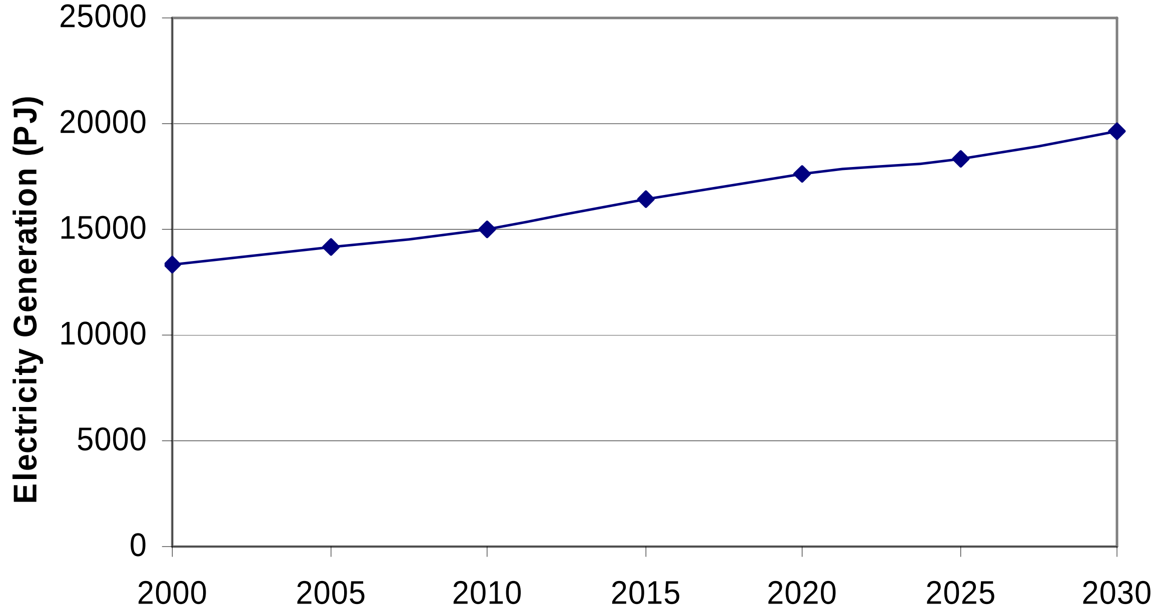

Figure 2.2: Baseline Electric Generation

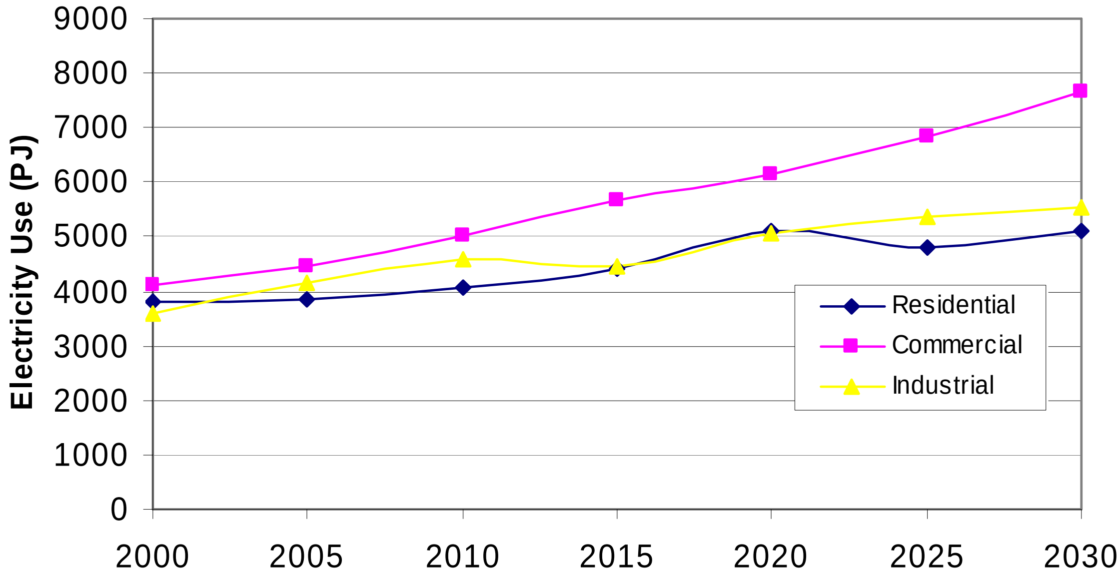

Figure 2.3: Electricity Use by Demand Sector

Capacity Additions

To meet this demand growth, the model adds a total of 293 GW of new electric generation capacity between 2000 and 2030. More than 76% of the new capacity is in the form of natural gas technologies, with 61% being natural gas combined cycle and 15% being natural gas combustion turbines (Figure 2.4). New conventional coal-fired power plants are not added until 2020 and later, though a small amount of integrated gasification combined cycle generation comes on-line in 2015. Renewables add 34 GW of capacity, with 61% coming from wind power generation, 15% from biomass combined cycle, and 14% from geothermal.

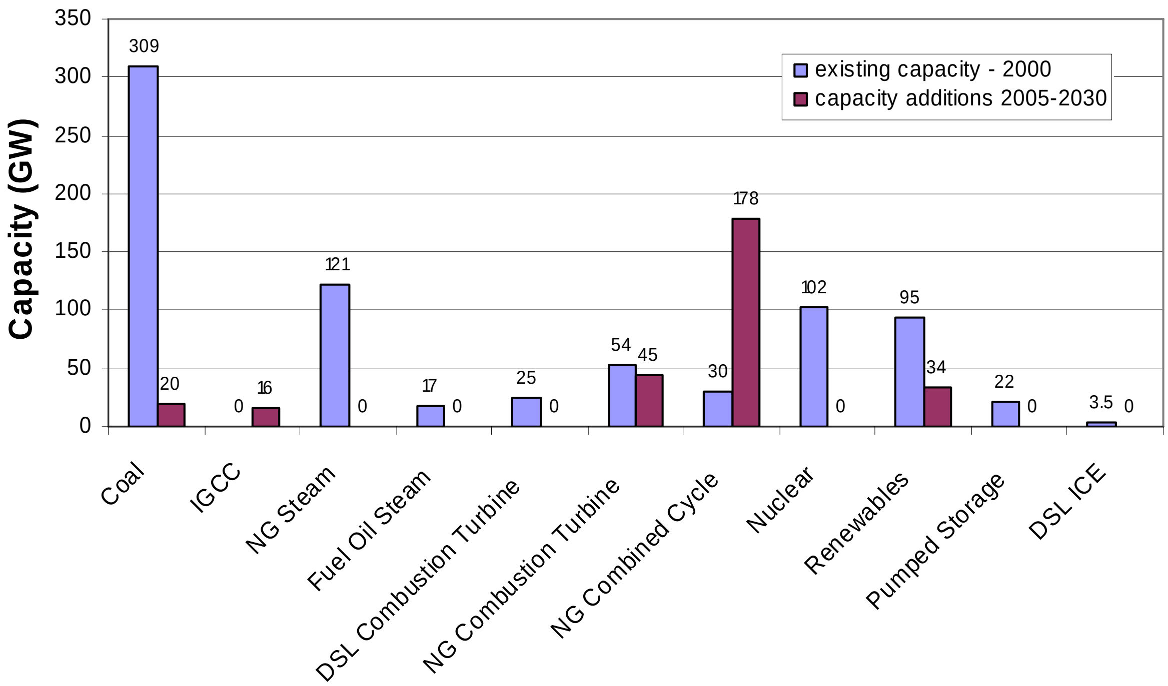

Figure 2.4: Current Capacity and Capacity Additions

Electricity Generation by Fuel

Coal-fired power plants continue to generate the most electricity (Figure 2.5). As electric sector emissions constraints tighten over time, more of the original plants are retrofitted with NO_X and SO_2 controls, and 20 GW of new capacity is built. New coal capacity includes FGD for SO_2 and SCR for NO_X and therefore does not need retrofit technologies for emissions controls. Nuclear power capacity increases slightly, but this is due to capacity upgrades at existing facilities. No new nuclear plants are built in the BAU case. Overall, coal electric generation grows 0.5% annually, natural gas grows 3.8%, and renewables grow 2.7%.

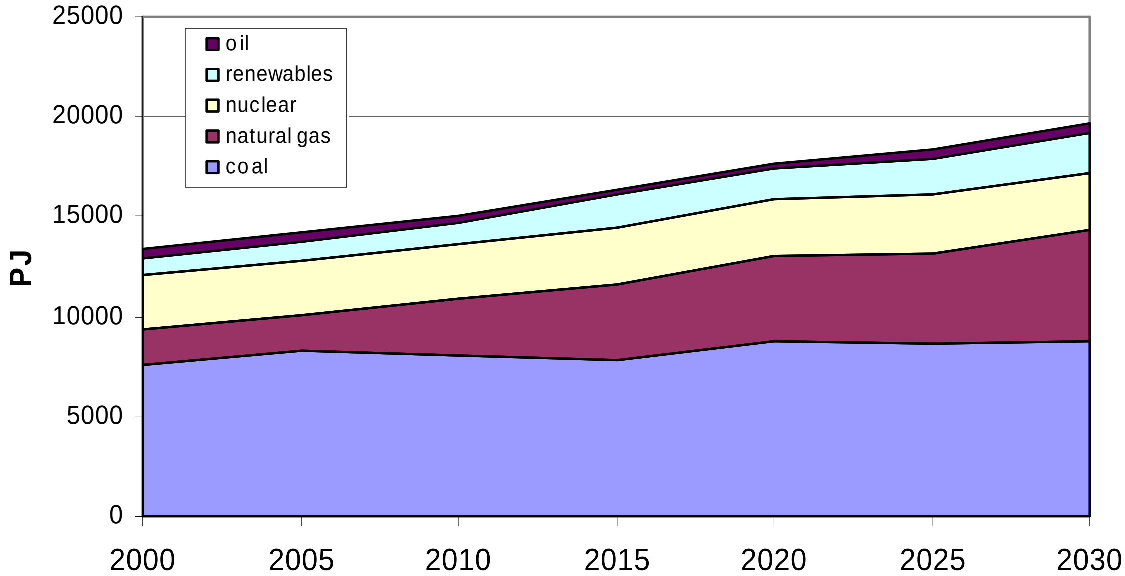

Figure 2.5: Electric Generation by Fuel Type

Use of Coal Retrofits

The EPANMD representation of retrofits is simplified in that it averages emissions over the whole country and ignores regional issues related to air quality. As a result, the retrofit coal capacity is smaller than it actually is (or will be), and when retrofits are selected they tend to be lower cost technologies with lower removal efficiencies.

Retrofits for SO_2 control are currently installed on 4.8% of existing coal fired power plants. Tightening of emissions constraints leads to FGD units being installed on over 14% of plants (Figure 2.6). Low NO_X Burners (LNB) for NO_X control are currently on 80% of existing plants. Over time, SNCR units are added to the existing LNB units for increased emissions reductions. In later years, SCR units play a larger role (Figure 2.7); SCR would be favored earlier if the EPANMD included emissions trading.

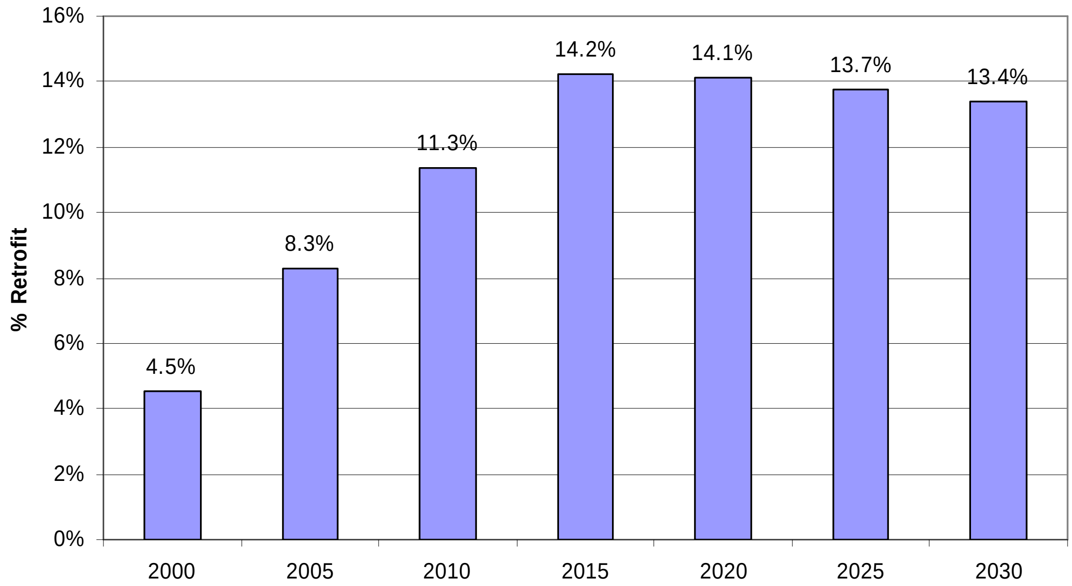

Figure 2.6: SO_2 Retrofits

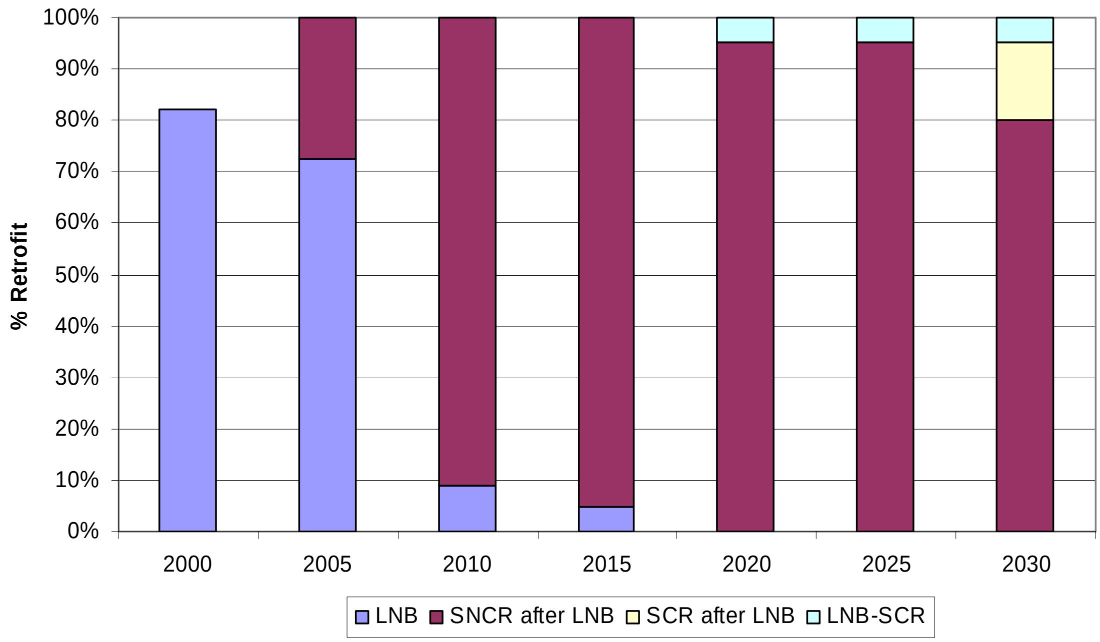

Figure 2.7: NO_X Retrofits

Emissions

CO_2 emissions in the electric sector grow 1% annually from 689,296 kt in 2000 to 927,302 kt in 2030 (Figure 2.8). The model constrains NO_X and SO_2 starting in 2010 and 2015, respectively, to conform with DOE projections of the impacts from the Clean Air Act regulations. These constraints are binding over the applicable time periods and emissions do not drop below the upper limits (Figure 2.9).

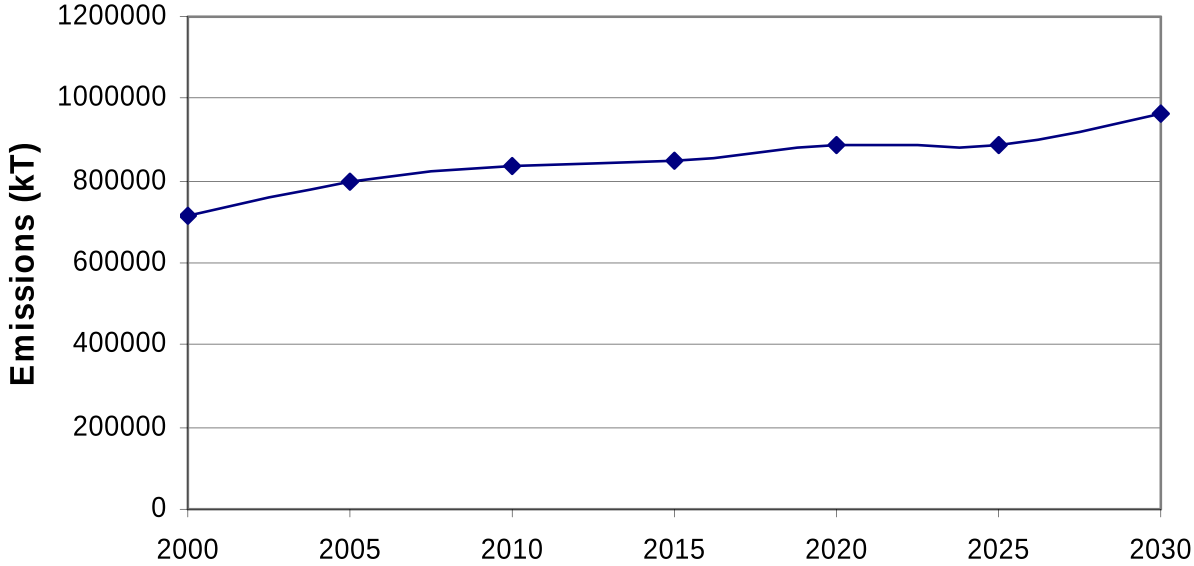

Figure 2.8: Carbon Emissions in the Electric Sector

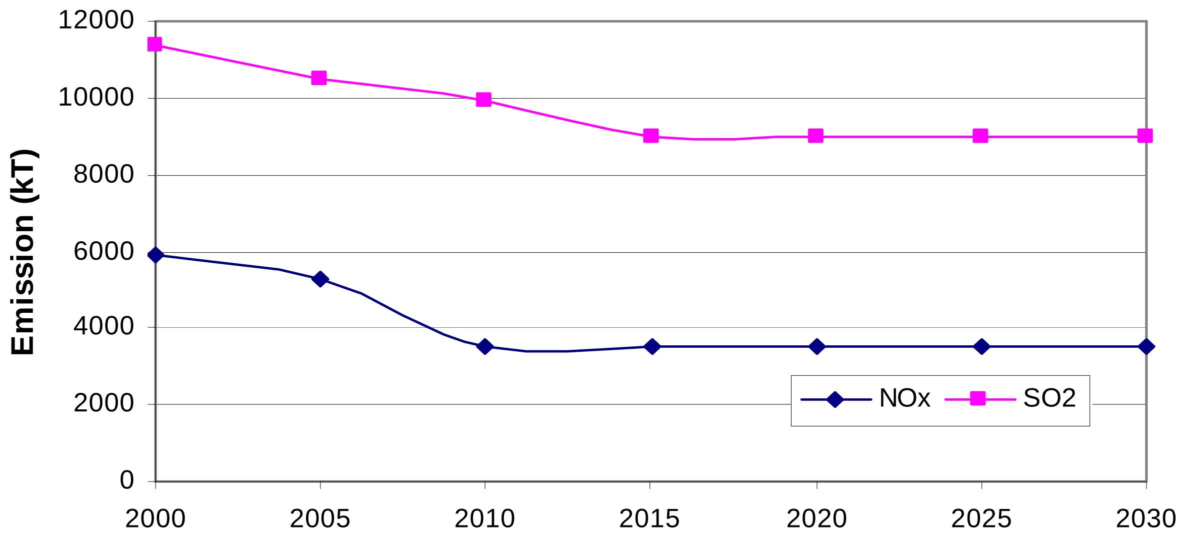

Figure 2.9: NO_X and SO_2 Emissions in the Electric Sector

Section 3

Sensitivity Analysis of the EPANM Database

The MARKAL Business As Usual (BAU) case presented in Section 2 provides a projection of the evolution of the U.S. energy system from 1995 through 2030. The BAU case was generated using best estimates for the values of model inputs, such as the characteristics of current and future technologies, energy service demands, and regulations on criteria pollutant emissions. Since the true values for many of these inputs are unknown, the BAU case represents only one of many possible outcomes. Further, it does not itself convey information regarding the sensitivity of the energy system to alternative input assumptions.

This section describes the application of formal sensitivity analysis techniques to evaluate the model's response to changes in input assumptions. The results aid in characterizing and communicating the drivers that lead to such outcomes as: the penetration of particular technologies, a decrease in pollutant emissions, or a reduction in fossil fuel imports. Sensitivity analysis also allows one to view the BAU case in the context of the range of possible future energy scenarios that may occur.

3.1 Background – Sensitivity Analysis

To evaluate sensitivities within the EPANM database and model, both global and parametric sensitivity techniques were used. Global sensitivity analysis techniques typically are applied in practice when the goal is to characterize the relationships among model inputs and outputs over a wide range of input conditions. In contrast, parametric sensitivity analysis, also known as local sensitivity analysis, is used to evaluate the response to a change in a single input, holding all other inputs constant. This subsection provides background information about sensitivity analysis techniques within these categories. For more information about sensitivity analysis, see publications by Saltelli et al., (2000) and Cullen and Frey (1999).

Global sensitivity analysis involves perturbing multiple model inputs simultaneously and evaluating the effects of each input or of combinations of inputs on model outputs. Inputs are often perturbed via Monte Carlo simulation. In Monte Carlo simulation, statistical or empirical distributions are assumed for inputs of interest. A value is sampled from each distribution, and the resulting set of values is fed into the model. The values of relevant outputs are recorded. The combination of a set of inputs and the corresponding outputs constitutes one potential "realization." Typically fifty to several hundred realizations are generated in a Monte Carlo simulation. These realizations are then evaluated using visualization and statistical techniques to characterize the nature and strength in the relationships among inputs and outputs.[1]

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[1] Monte Carlo techniques are also used in uncertainty and risk analyses. In uncertainty analysis, the distributions of model outputs are characterized to estimate the uncertainty associated with each. In risk analysis, the output values are compared with a particular metric to determine the likelihood that the metric will or will not be exceeded. In these techniques, much effort is typically put into developing the input distributions since these will have an impact on the output distributions. In global sensitivity analysis, however, uniform distributions may suffice since the goal is to characterize the range of potential combinations of inputs.

A variety of global sensitivity analysis techniques are available, with the selection of the best technique for a particular application being a function of factors such as the degree of linearity in the input-output relationships, the number of realizations and their coverage of the possible outcomes, and the type of sensitivity information desired. One straightforward, readily applied approach is correlation analysis. Correlation coefficients can be calculated between any combination of inputs and outputs to the model. The resulting coefficients indicate whether there is a strong linear relationship between each pair and whether this relationship is positive or negative. Correlation coefficients cannot characterize the impact of combinations of inputs on an output and may provide misleading results if applied to nonlinear relationships. In contrast, scatterplots and various exploratory visualization techniques can be used to identify linear or nonlinear relationships. These techniques typically require human expertise to visually identify relationships, and thus tend to be qualitative instead of quantitative.

Linear regression techniques also are used in global sensitivity analysis. Regression can evaluate the impact of multiple inputs simultaneously. Further, if inputs are normalized along their ranges, the resulting regression coefficients indicate the relative impact of each input on an output. Like correlation coefficients, linear regression may not be well suited for characterizing nonlinear relationships or those in which the input-output relationships involve discrete behavior. Nonlinear regression techniques, regression trees, and statistical analysis of variance (ANOVA) approaches may address these issues for some problems.

Parametric sensitivity analysis, in which one input is perturbed while others are held constant, is very useful in characterizing incremental responses to changes in inputs from a base or reference case. These responses can be characterized quantitatively, such as with a sensitivity metric or empirical derivative, or graphically. While parametric techniques do not characterize responses over combinations of inputs, they often play an important role both in preliminary analyses, as a cursory means to identify sensitivities of interest, and in more detailed analyses of input-output responses.

Global and parametric sensitivity techniques can be used independently or together. This analysis uses two global sensitivity analysis techniques, correlation analysis and normalized linear regression, to make broad observations regarding input-output relationships. Global sensitivity analysis was followed by a parametric analysis to provide more detailed information about impacts of changes in specific inputs in the context of the BAU case.

3.2 Methodology

Steps taken to carry out the sensitivity analysis of MARKAL include:

- Key model outputs were identified, as were the input assumptions expected to impact those outputs;
- For each input, a range was estimated;
- Monte Carlo simulation was carried out, with the inputs and outputs of each of 1000 realizations tracked;
- The Monte Carlo inputs and outputs were analyzed using correlation analysis to provide insight regarding correlations and tradeoffs;

- Monte Carlo results were also evaluated with normalized multiple linear regression to estimate the relative impact of each input value on each output; and
- From the normalized regression analysis, the inputs with the highest influence on outputs were identified, and parametric sensitivity runs were used to evaluate model responses in more detail.

3.3 Selecting Inputs and Outputs

With a focus on the electric sector, key outputs for the year 2030 were identified. These included: the market penetrations of various electricity generation technologies; fuel use in generating electricity; the summer day peak marginal electricity price; NO_X, SO_2, and CO_2 emissions from the electric generation sector; utilization of existing electricity generation capacity; and use of NO_X controls on coal-fired boiler emissions. Since the electric sector interacts with the rest of the energy system, system-wide fuel use, emissions, and fossil fuel imports were also selected. In the category of system-wide fuel use, the fuels that were tracked include coal, natural gas, oil, petroleum, uranium, and renewables, which include solar power, wind power, hydropower, geothermal, and biomass. Oil and petroleum are differentiated because oil includes domestic and imported crude oil, both of which are refined domestically, while petroleum includes imported petroleum products.

Inputs included in the analysis were: the future costs of natural gas, coal, and oil; the hurdle rate for new electric generation technologies; future nuclear capacity; growth bounds on renewables (for biomass, landfill gas, hydropower, geothermal, solar, and wind); and the availability factor and maximum capacity of coal gasification technologies. Each of these inputs was expected to have an impact on the selected outputs.

The next step in the analysis was to characterize ranges for the inputs. Each of the inputs, which were assumed to be independent of each other, was represented with a uniform distribution. The bounds of the distributions are shown in Table 3.1 and reflect modeler's judgment. Fuel inputs were allowed to range from approximately -20% to +100% of their 2030 values in the BAU case. The range was biased toward the high end to represent uncertainties related to political instability and concerns about resource limitations. One half of the fuel cost change was implemented in 2015, with the remaining half coming into effect in 2020.

The hurdle rate for new electricity generation technologies ranged from 0.05, the current system-wide discount rate, to 0.20. Nuclear power capacity was allowed to range from 1995 levels to 125% of 1995 levels. One third of any increase in nuclear capacity was specified to come online in 2015, with the remainder entering in 2020. In our modeling, nuclear power capacity is constrained to specific levels instead of allowing nuclear to penetrate via economics. This modeling approach was taken to reflect the assumption that policy is the major driver that limits or expands nuclear capacity.

Ranges for growth rates for renewables were selected to encompass the default values. The availability factor for coal gasification ranged from 82.5% to 87.5%, and the overall capacity limit for the technology ranged from 0 to 1000 PJ.

Table 3.1: Ranges for inputs used in the Monte Carlo simulation

Input	Units	Default	Low	High	Description
Natural gas cost increase	$M/PJ	0.0	-0.896	8.86	Cost added to the natural gas and liquid natural gas supply curves
Oil cost increase	$M/PJ	0.0	-0.712	7.12	Cost added to the supply curves imported and domestic fuel oil, as well as to imported petroleum fuels
Coal cost increase	$M/PJ	0.0	-0.5	1.5	Cost added to the coal supply curves
New ELC technology hurdle rate	None	0.18	0.05	0.20	Technology-specific discount rate applied to all electric sector technologies except renewables
Nuclear power capacity multiplier	None	1.0	1.0	1.25	Multiplier used to increase future nuclear capacity
Biomass growth rate bound	% growth per 5-yr period	9.0	0.0	25.0	Growth rate on biomass use in electricity generation
Geothermal growth rate bound	% growth per 5-yr period	17.0	0.0	20.0	Growth rate on geothermal power for electricity generation
Hydropower growth rate bound	% growth per 5-yr period	0.0	0.0	10.0	Growth rate on hydropower for electricity generation
Landfill gas growth rate bound	% growth per 5-yr period	11.0	0.0	25.0	Growth rate for the combustion of landfill gas from municipal solid waste landfills for electricity generation
Solar PV growth rate bound	% growth per 5-yr period	50.0	2.5	50.0	Growth rate for solar photovoltaics in electricity generation
Solar thermal growth rate bound	% growth per 5-yr period	3.0	0.0	10.0	Growth rate for solar thermal technologies in electricity generation
Wind growth rate bound	% growth per 5-yr period	21.0	0.0	50.0	Growth rate for wind turbines in electricity generation
IGCC availability factor	None	0.846	0.825	0.875	Fraction of time during which IGCC is operational
IGCC maximum capacity bound	Gigawatts	16.0	0.0	1000.0	Peak capacity for IGCC technologies in 2030

One thousand Monte Carlo realizations were performed and the inputs and outputs tabulated. Correlation analysis and normalized multiple linear regression were then applied.

3.4 Global Sensitivity Results - Correlation Analysis

Correlation coefficients were calculated for each combination of model inputs and outputs for the year 2030. The resulting coefficients are provided in Tables 3.2 through 3.5. In each table, correlation coefficients with absolute values of less than 0.1 are not shown, while those with absolute values greater than 0.7 are emphasized via bold type and light shading.

Table 3.2: Correlation coefficients between model inputs and electric sector outputs

Outputs	Natural Gas Cost	Oil Cost	Coal Cost	New ELC Technology Hurdle Rate	Nuclear Capacity	Biofuels Growth Rate	Geothermal Growth Rate	Hydropower Growth Rate	Landfill Gas Growth Rate	Solar PV Growth Rate	Solar Thermal Growth Rate	Wind Growth Rate	IGCC Availability	IGCC Capacity Limit
Electricity Generated by Various Fuels														
Pulverized Coal	-0.42	-0.14		-0.22	-0.29	-0.26		-0.25						
Gasified Coal														
Oil	0.3	-0.67			-0.12			-0.11						
Natural Gas	-0.55	0.49		-0.19	-0.13	-0.12								
Nuclear Power					**1**									
Geothermal							**1**							
Biofuels		0.19				**0.86**								
Landfill Gas														
Solar Power	0.19			-0.65						0.36	0.33			
Wind Power	0.12			-0.29								**0.76**		
Use of NO_X Controls on Coal-Fired Power Plants	0.24			0.56										
Peak Electricity Price	0.64			**0.76**										
Emissions from the Electric Sector														
CO_2	-0.44	-0.45		0.41	-0.33	-0.21		-0.26						
NO_X														
SO_2														

Table 3.2 shows the correlation coefficients between each input and tracked electric sector output. Only five of the input-output pairs have correlations greater than 0.7. The lack of a larger number of strong linear relationships is indicative of the complexity of the system, which allows for discrete behavior associated with selecting technologies and fuel switching.

Many of the correlations that are shown in the table verify anticipated behavior. For example, the new electricity generation technology hurdle rate and peak electricity price had a correlation of 0.76, indicating that inhibiting uptake of new technologies for electricity generation resulted in an increase in energy prices. Similarly, although the correlation is only 0.56, there appeared to be a relationship between the hurdle rate and the use of controls on NO_X emissions from coal-fired power plants: as it became more difficult for new, cleaner electric generation technologies to be adopted, reliance on retrofits such as selective catalytic reduction increased.

While it is not a strong correlation, there does appear to be an inverse relationship between the cost of natural gas and the use of coal. This relationship can be attributed to the effect of the limit on electric sector NO_X emissions. Increased natural gas costs led to decreased use of natural gas in electricity generation. Because natural gas-fueled technologies have lower NO_X emission rates than coal-fueled technologies, however, natural gas could only be substituted for by coal if increased NO_X controls were used on coal-fired boilers. The model instead, based upon a comparison of the relative costs, opted to fill this gap with oil-fueled technologies. While oil has fewer NO_X emissions than coal, its emissions are greater than natural gas. Reductions in coal use were required to compensate. These relationships are evident in the results of the normalized multiple linear regression, shown in Figures 3.1 through 3.9.

Table 3.3 shows correlation coefficients between inputs and system-wide outputs. Only eight of these coefficients exceeded 0.7. Many of the coefficients again confirmed expected behavior. For example, natural gas cost increases resulted in decreased system-wide use of natural gas, compensated for by increased use of renewables and petroleum.

An interesting result was that oil costs were much more highly correlated with NO_X and SO_2 emissions than natural gas or coal costs were. This is because the primary use of natural gas in the model is in electricity generation, but the representation of the Clean Air Act emission constraints places limits on the emissions of NO_X and SO_2 from that sector. In contrast, the transportation sector is the primary user of oil, and this sector is not subject to NO_X and SO_2 emissions constraints.

The lack of strong correlations for some pairs was also insightful. For example, over the growth rate constraints evaluated, market penetrations of various renewables did not appear to have had a strong impact on system emissions or fuel use.

Table 3.3: Correlation coefficients between model inputs and system-wide outputs

Outputs	Natural Gas Cost	Oil Cost	Coal Cost	New ELC Technology Hurdle Rate	Nuclear Capacity	Biofuels Growth Rate	Geothermal Growth Rate	Hydropower Growth Rate	Landfill Gas Growth Rate	Solar PV Growth Rate	Solar Thermal Growth Rate	Wind Growth Rate	IGCC Availability	IGCC Capacity Limit
System-Wide Emissions														
CO_2	-0.29	-0.59		0.5	-0.29	-0.17		-0.24						
NO_X	0.14	**-0.82**												
SO_2	0.3	**-0.74**		-0.16				-0.11						
Fuel Inputs to System														
Renewables	**0.84**	0.19		-0.16		0.14	0.14	0.18						
Coal	-0.5	0.28			-0.14	-0.17		-0.12						
Petroleum	**0.87**			0.11										
Oil	-0.12	**-0.79**												
Natural Gas	**-0.91**			0.27										
Liquid Natural Gas	**-0.82**													
Uranium					**1**									
Net Imports	0.68	-0.5		0.16										

Table 3.4 shows correlation coefficients between electricity sector outputs and all tracked outputs. Very few of the values in this table show a strong degree of correlation (values of 1.0 typically correspond to comparisons of the same output (e.g., pulverized coal vs. pulverized coal). These correlation coefficients plus those repeated elsewhere in the table are shaded. The coefficients in the table provide an indication that fuel-switching was occurring between natural gas and oil in electricity generation.

System-wide NO_X and SO_2 emissions showed a high degree of correlation with the use of oil in electricity generation. Increased system-wide emissions were not a result of the electric sector, however, since its NO_X and SO_2 emissions are constrained. Instead, they were a result of fuel and technology switching within the transportation sector in response to drivers of favorable oil costs.

Net imports of fossil fuels appeared to be correlated with oil use in electricity generation, but inversely correlated with natural gas use. These correlations indicate that increased demands for oil resulted in increased fossil fuel imports. At the quantities modeled, most of the natural gas was supplied domestically, and thus had a negative correlation with imports.

Table 3.4: Correlation coefficients between electric sector and all outputs

All Tracked Outputs	Electric Sector Outputs: Electricity Generated by Various Fuels: Pulverized Coal	Oil	Natural Gas	Nuclear Power	Geothermal	Biofuels	Solar Power	Wind Power	Use of NOx Controls on Coal-Fired Power Plants	Peak Electricity Price	CO2 from Electric Sector
Electricity Generated by Various Fuels											
Pulverized Coal	1.00	-0.16	0.12	-0.29		-0.24				-0.38	0.55
Oil		1.00	-0.65	-0.12		-0.21				0.19	0.38
Natural Gas			1.00	-0.13						-0.48	
Nuclear Power				1.00							-0.33
Geothermal					1.00						
Biofuels						1.00					-0.33
Solar Power							1.00	0.18	0.61	-0.35	-0.39
Wind Power								1.00	0.17	-0.17	-0.29
Use of NO_X Controls on Coal-Fired Power Plants									1.00	-0.38	-0.55
Peak Electricity Price										1.00	
CO2 from Electric Sector											1.00
System-Wide Emissions											
CO_2	0.41	0.51	-0.27	-0.29		-0.32	-0.42	-0.29	-0.57	0.20	**0.96**
NO_X		**0.85**	-0.60			-0.24			-0.11	0.13	0.46
SO_2		**0.88**	-0.57			-0.23	0.16		0.13		0.27
Fuel Inputs to System											
Renewables	-0.51		-0.34		0.15	0.21	0.29	0.26	0.34	0.37	-0.67
Coal	**0.76**	-0.62	0.36	-0.14			-0.19		-0.18	-0.22	0.33
Petroleum	-0.32	0.40	-0.54				0.12		0.17	0.64	-0.25
Oil		0.65	-0.47			-0.15			-0.13	-0.11	0.47
NGA	0.32	-0.36	0.55				-0.35	-0.20	-0.47	-0.35	0.51
NGL	0.27	-0.29	0.55				-0.13		-0.19	-0.55	0.31
Uranium	-0.29	-0.12	-0.13	**1.00**							-0.33
Net Imports	-0.23	**0.73**	**-0.74**			-0.12				0.53	

Table 3.5 shows correlation coefficients between combinations of system-wide outputs. Among the notable relationships are the inverse correlations between system-wide natural gas use and both renewables and petroleum use.

Table 3.5: Correlation coefficients between system outputs and all outputs

	System-Wide Output										
	Emissions			Fuel Inputs to System							
System-Wide Output	CO_2	NO_X	SO_2	Renewables	Coal	Petroleum	Oil	Natural Gas	Natural Gas Liquids	Uranium	Net Imports
System-Wide Emissions											
CO_2	1.00	0.63	0.40	-0.56	0.16	-0.11	0.60	0.38	0.16	-0.29	0.29
NO_X		1.00	**0.89**		-0.49	0.25	**0.80**	-0.20	-0.22		0.69
SO_2			1.00	0.14	-0.63	0.40	0.63	-0.42	-0.30		0.70
Fuel Inputs to System											
Renewables				1.00	-0.50	0.66	-0.22	**-0.87**	-0.66		0.41
Coal					1.00	-0.48	-0.22	0.51	0.37	-0.14	-0.55
Petroleum						1.00	-0.13	**-0.77**	**-0.91**		**0.82**
Oil							1.00				0.45
Natural Gas								1.00	0.75		-0.62
Natural Gas Liquids									1.00		**-0.83**
Uranium										1.00	
Net Imports											1.00

3.5 Global Sensitivity Results - Normalized Linear Regression

To evaluate the relative magnitude of impact (as opposed to correlation) of each input on the tracked outputs, normalized linear regressions were used. Normalization was carried out so that the coefficients on each term would be directly comparable. Regression results are depicted graphically in the tornado diagrams provide in Figures 3.1 through 3.9. Tornado diagrams were used to present the regression results since these diagrams visually convey the sign and relative magnitude of influence of each input. R^2 values are provided to give an indication of the quality of the fit, indicating the ratio of explained variance to total variance.

In Figure 3.1, the factor with the greatest influence on the quantity of coal used was natural gas cost. As seen in Table 3.2, increased natural gas costs led to *decreased* coal use. The correlation between coal and nuclear power in electricity generation is much more straightforward since nuclear power would offset coal in supplying base load electricity. In comparison, the correlations between nuclear and natural gas and between nuclear and oil were much weaker.

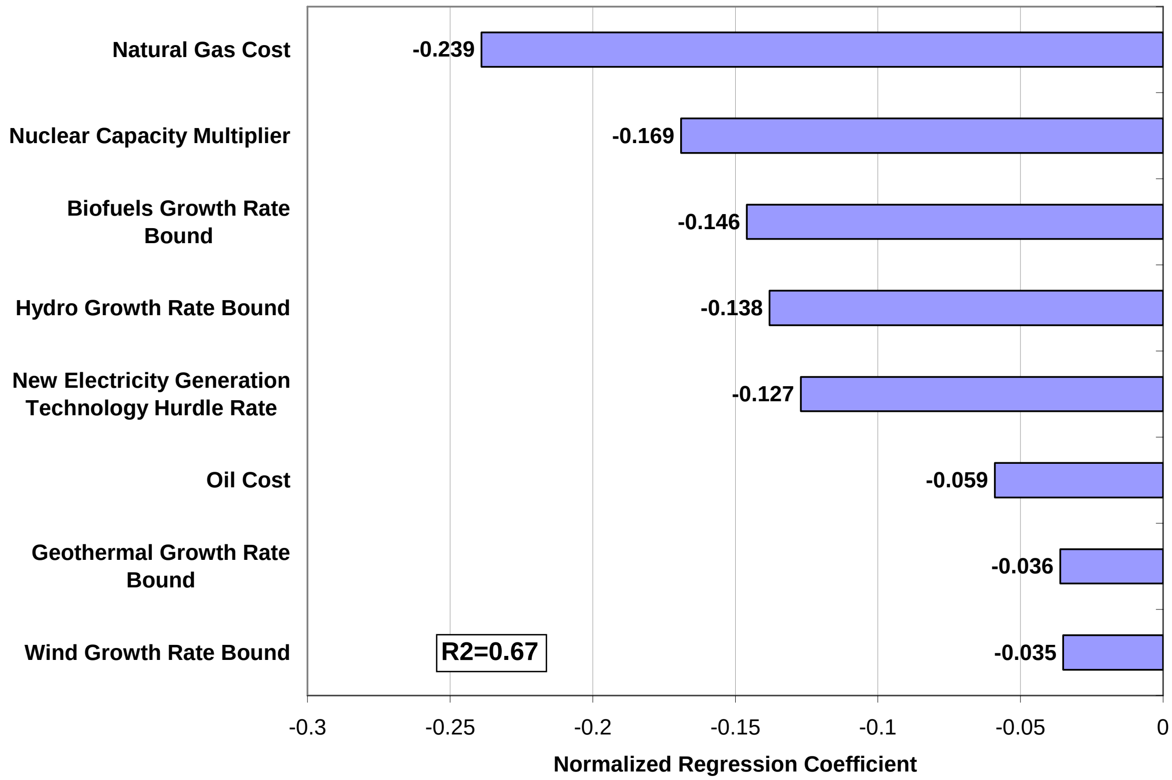


Figure 3.1: Factors affecting use of coal in electricity generation

Figure 3.2 provides an indication of the relative sensitivities of natural gas use in electricity generation to the Monte Carlo inputs. As might be expected, natural gas use decreased with increases in natural gas costs, but increased with higher oil costs. The impact of the hurdle rate, which inhibited the introduction of new, more efficient natural gas technologies, was only about a third as important as either of these two cost factors.

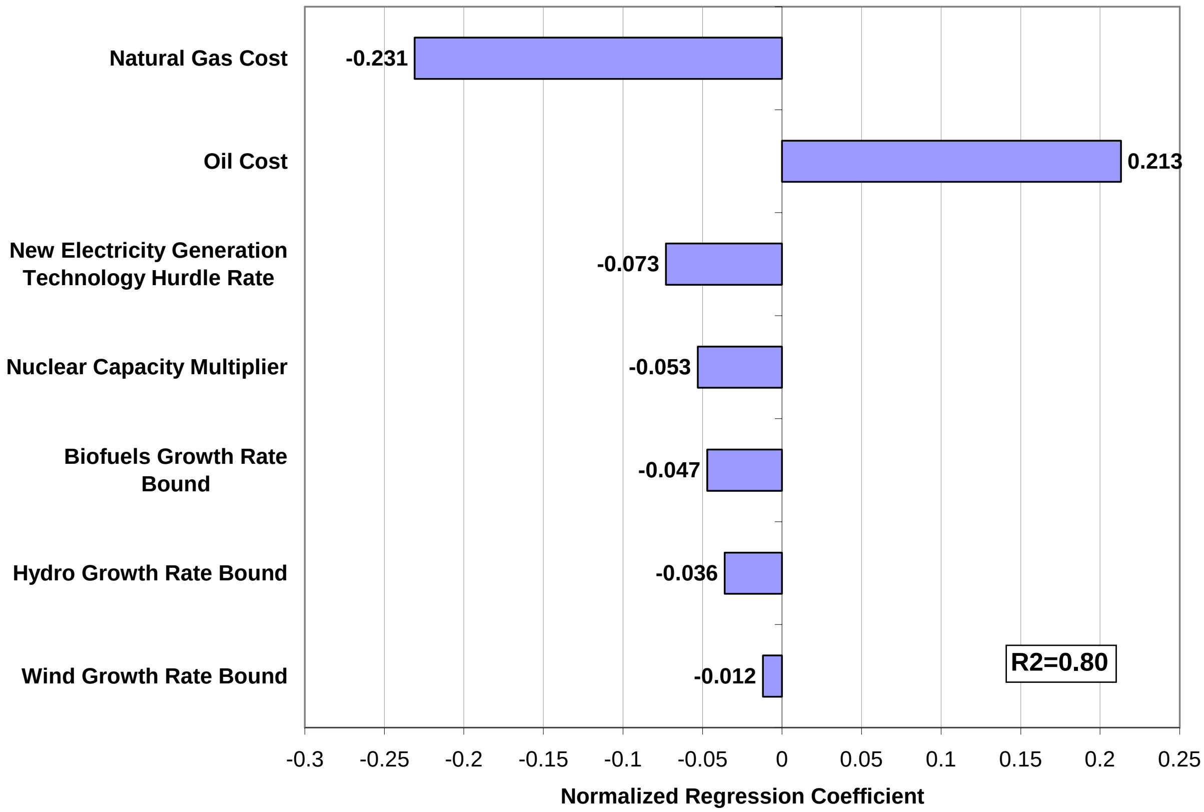


Figure 3.2: Factors affecting use of natural gas in electricity generation

Figure 3.3 shows the sensitivities of oil use in electricity generation to the various Monte Carlo inputs. Oil cost increases were the major factor affecting penetration. Natural gas cost increases had approximately half the impact. The influence of nuclear capacity is less than one half that of natural gas cost.

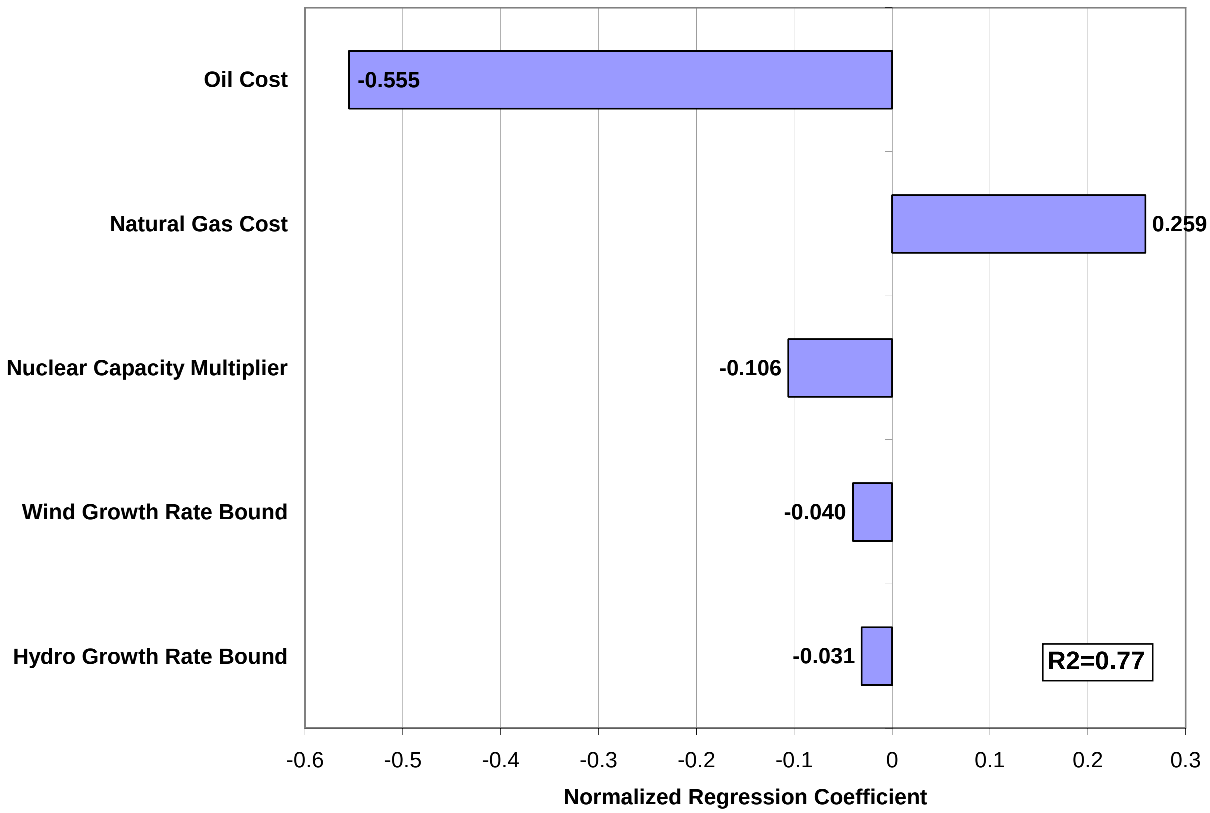


Figure 3.3: Factors affecting use of oil in electricity generation

Figure 3.4 indicates that CO_2 emissions from the electric sector were impacted the greatest by increases in natural gas and oil costs. For natural gas, this relationship represents the same behavior observed in Table 3.2: natural gas cost increases led to decreased penetration of natural gas-fueled electricity generation technologies. These technologies had fewer NO_X emissions than pulverized coal plants, and, as a result, the amount of coal used in electricity generation decreased to meet NO_X constraints. Because coal has higher CO_2 emissions than the other fuels, this decrease in coal use resulted in a decrease in CO_2 emissions as well. Similar behavior appeared to be occurring with increased oil costs.

The impact of the hurdle rate was only slightly lower than the cost of natural gas or oil. By making it more difficult for new, more efficient technologies to penetrate the electricity generation market, the hurdle rate led to increases in CO_2 emissions.

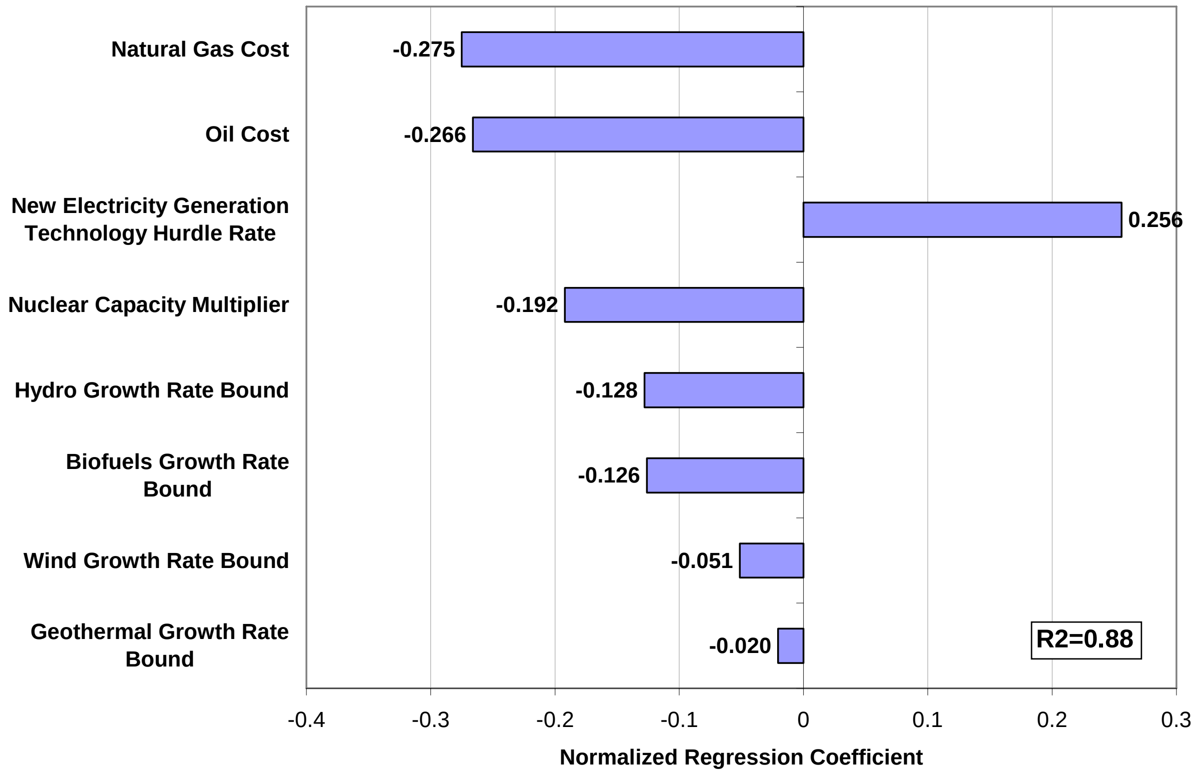


Figure 3.4: Factors affecting CO_2 emissions from electricity generation

Another expected result was that increased nuclear capacity led to decreased CO_2 emissions. This influence was not as strong as that of natural gas costs, oil costs, and hurdle rate, however, even though nuclear power has no CO_2 emissions. Again, the results were influenced by the NO_X limit on electricity generation. Increased use of nuclear power to meet base load electricity generation effectively freed space under the NO_X limit. The result was that fewer NO_X controls were placed on coal-fired power plant emissions and additional coal capacity was added, at the expense of natural gas and oil technologies.

The new technology hurdle rate had the greatest impact on the adoption of NO_X retrofit controls, such as selective catalytic reduction, at coal-fired power plants (Figure 3.5). Increases in the hurdle rate effectively required that additional existing coal-fired power plants remain online in 2030. To achieve electric sector NO_X constraints with these plants, greater use of NO_X controls was required.

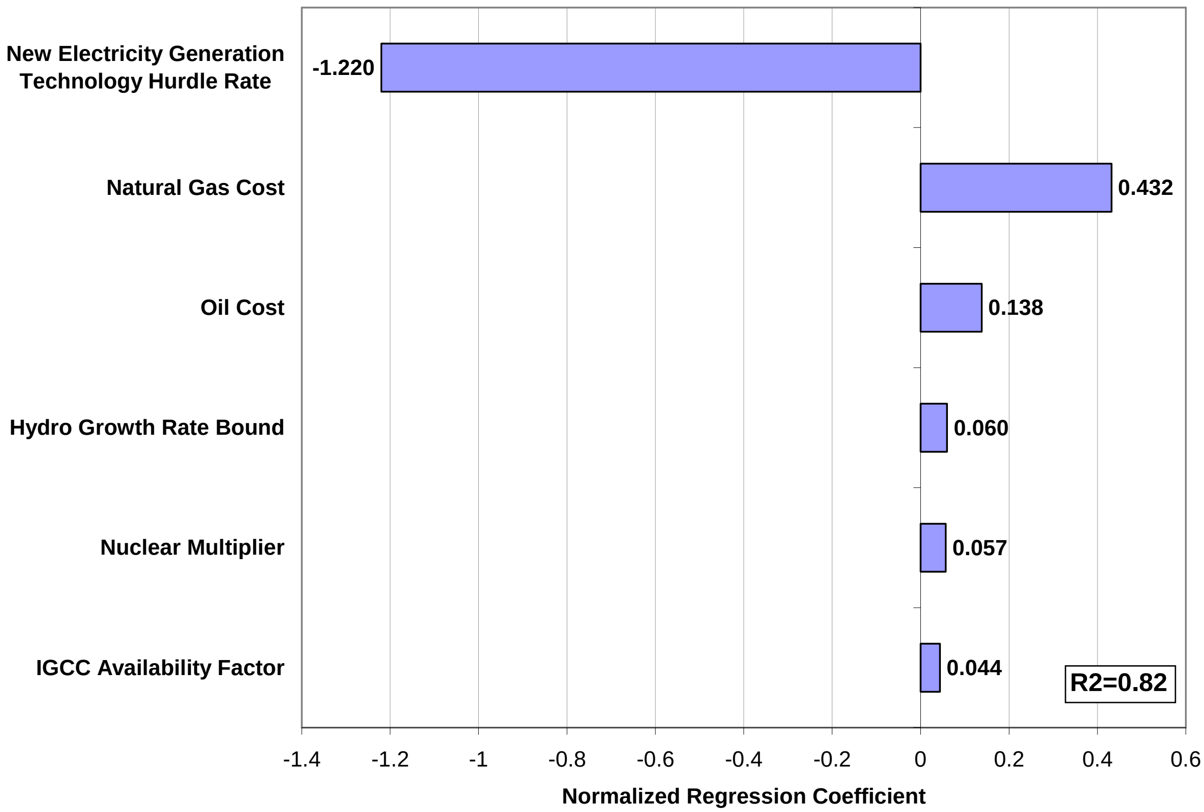


Figure 3.5: Factors affecting use of NO_X controls on coal-fired power plants

Figure 3.6 illustrates that increasing oil costs had the effect of reducing system-wide CO_2 emissions. Contributing factors were fuel and technology switching in the transportation sector. Additionally, fuel-switching within the electric generation sector may have played a role. By favoring existing coal-fueled electricity generation technologies, the hurdle rate had the effect of increasing system-wide carbon emissions.

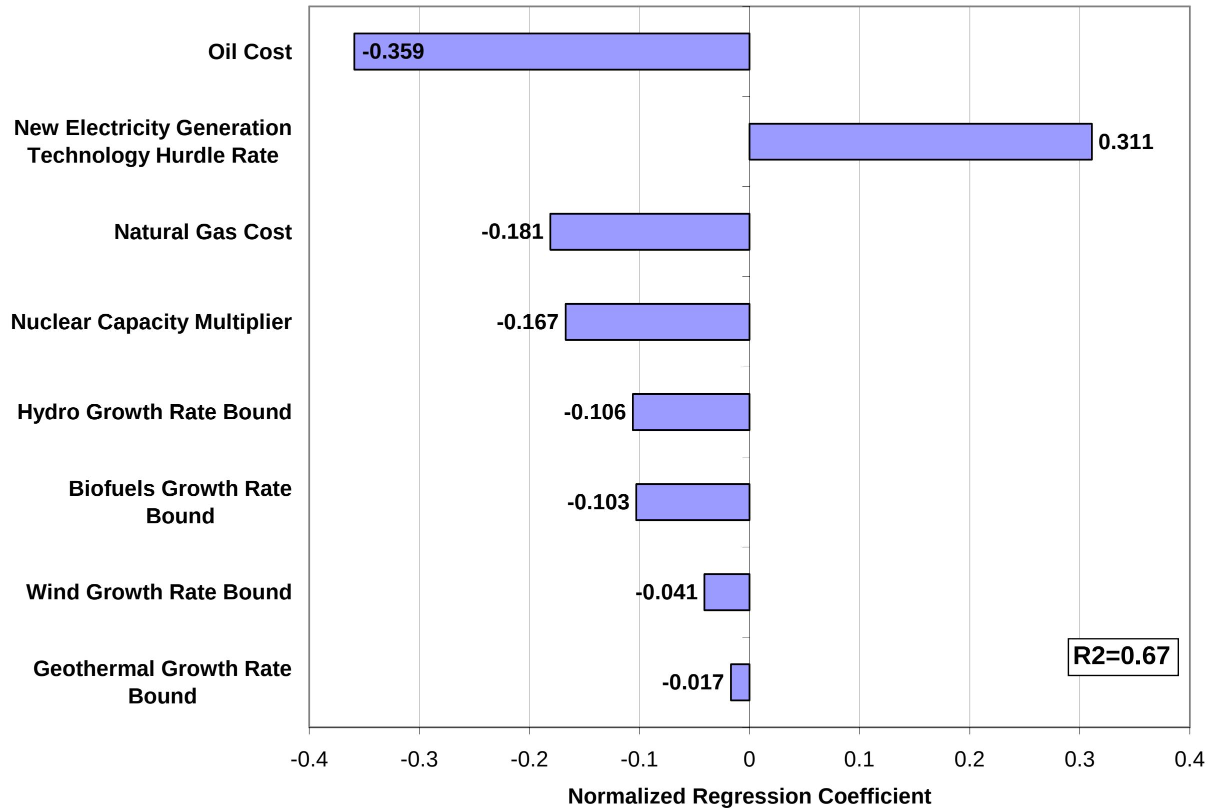


Figure 3.6: Factors affecting system-wide CO_2 emissions

The regression coefficients shown in Figure 3.7 indicate that SO_2 emissions were most sensitive to oil and natural gas costs. While SO_2 emissions from the electric sector were constrained, changes in SO_2 emissions were occurring in other sectors, primarily in the transportation sector. Decreased oil costs led to increased use of gasoline and diesel within the transportation sector. Diesel, in particular, has the potential to increase SO_2 emissions, although this impact will be reduced when new regulations on sulfur content in diesel fuels come into effect. These regulations are not currently represented in the MARKAL model.

The influence of increased natural gas costs was approximately half that of oil costs. One of the reasons that increased natural gas costs resulted in increased SO_2 emissions was because of switching from natural gas-fueled transportation technologies to oil-fueled technologies. Changes in SO_2 emissions may also have been influenced by resulting technology changes within the electricity sector, and resulting interactions with other sectors, although additional analyses would need to be carried out to characterize these impacts.

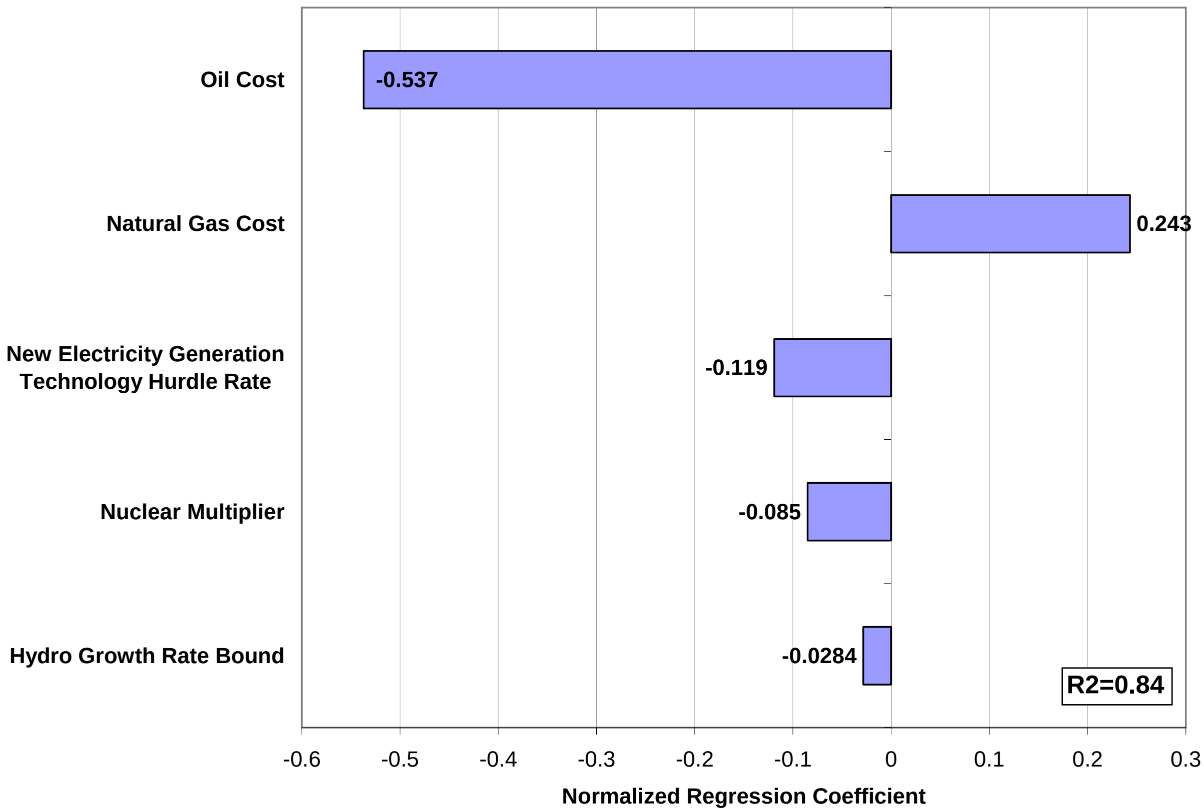


Figure 3.7: Factors affecting system-wide SO_2 emissions

Figure 3.8 presents the relative impacts of various inputs on system-wide NO_X emissions. As with SO_2, inexpensive oil inhibited the transition to more efficient vehicle technologies. The result was an increase in NO_X emissions. The impact of other drivers was relatively small.

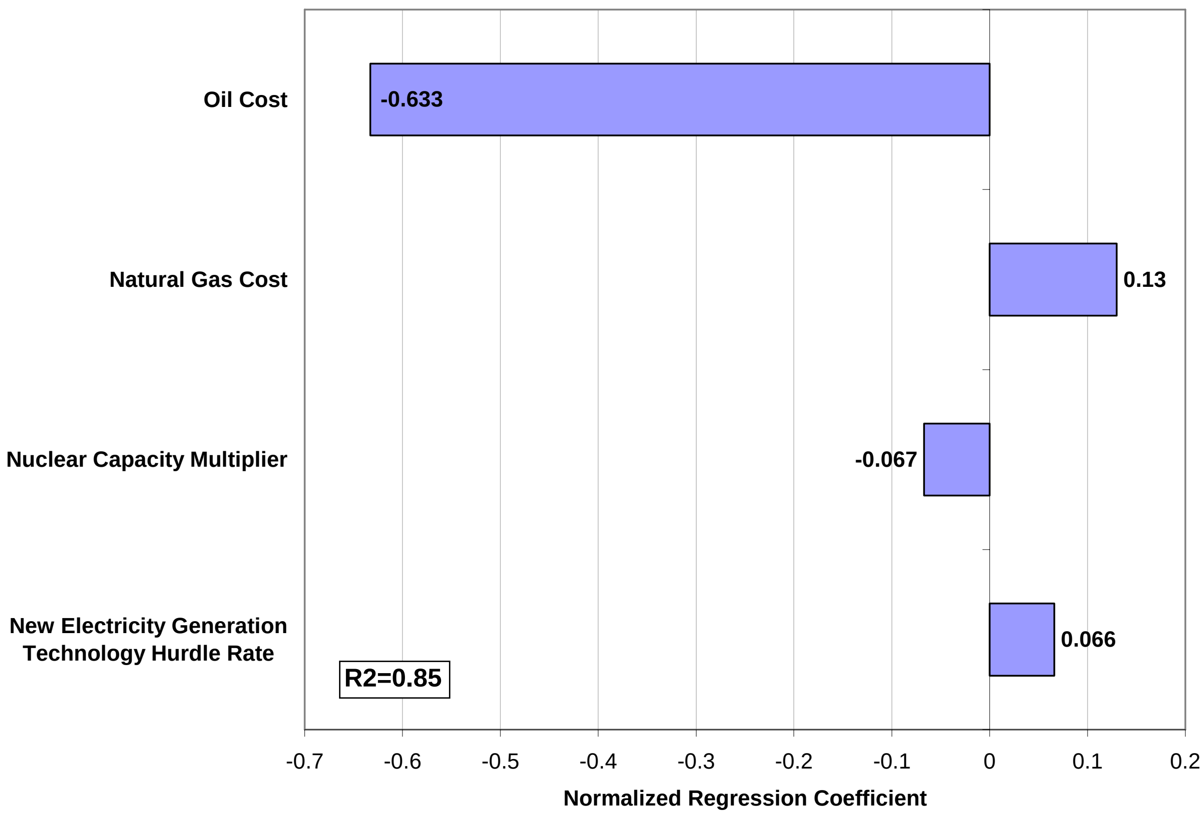


Figure 3.8: Factors affecting system-wide NO_X emissions

In MARKAL, reductions in fossil fuel imports can be achieved through either switching to more efficient technologies or switching to fuels that are supplied domestically instead of imported. Fuels that are largely supplied domestically in the model include coal, uranium, natural gas, and renewables. Oil and other petroleum products, in contrast, are largely imported fuels. Thus, in Figure 3.9, the two factors with the highest impact on imports were natural gas costs and oil costs, which had opposite effects on imports

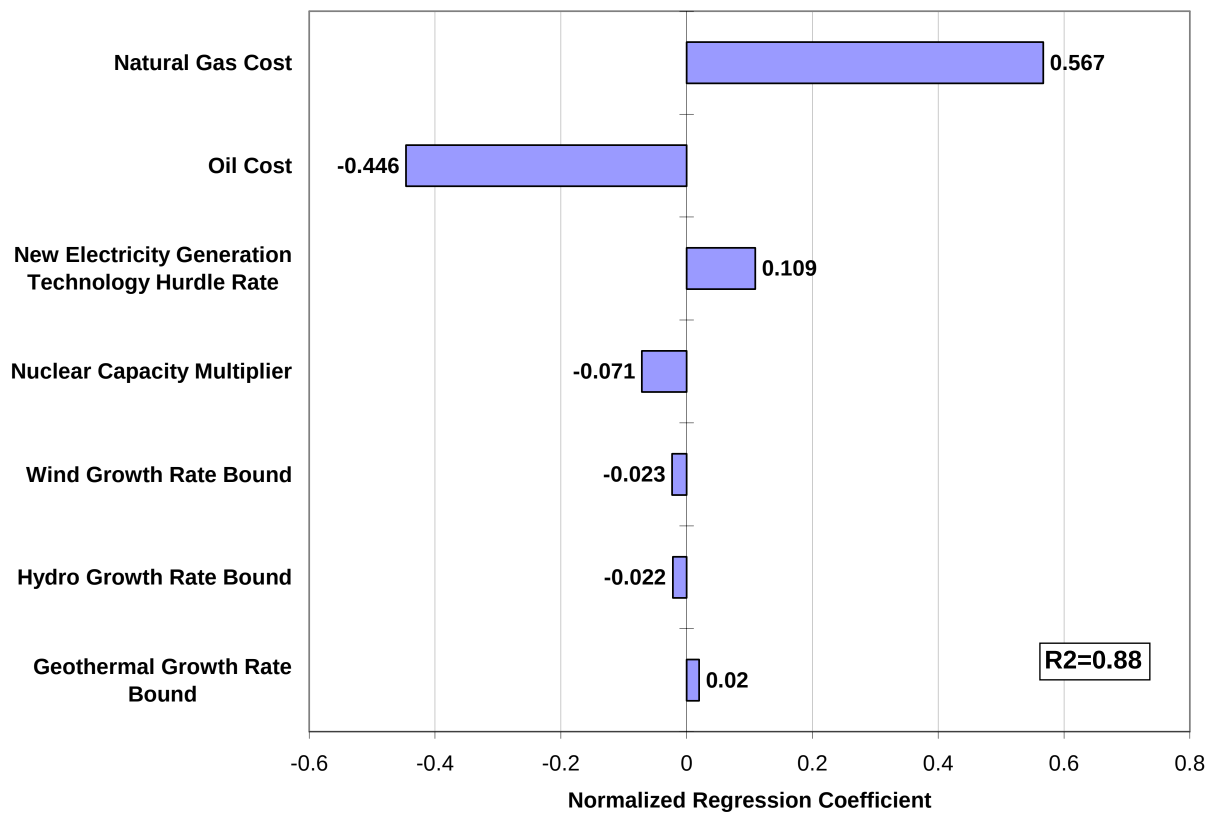


Figure 3.9: Factors affecting fossil fuel imports

3.6 Parametric Sensitivity Analysis

From the global sensitivity analysis, it was evident that many of the key outputs were most responsive to changes in natural gas and oil costs, nuclear capacity, and the hurdle rate for new electricity generation technologies. There were also cross-sector effects between the electricity generation and transportation sectors that had an impact on technology adoption, fuel use, and emissions.

A parametric sensitivity analysis was carried out to evaluate the effect of incremental changes in each of these inputs on the primary outputs of interest: fuel use within the electricity generation sector, system-wide emissions, and net imports. By evaluating changes parametrically, sensitivities around the baseline run were characterized. Results of the parametric runs are provided in Figures 3.10 through 3.16.

Figure 3.10 shows the change in electricity generation by fuel type as natural gas cost changed in relation to the baseline natural gas price in 2030. In this figure, as well as in Figures 3.11 through 3.13, electricity generation categories with outputs of less than 500 PJ are not shown. Decreases in natural gas costs led to an increase in natural gas use in electricity generation, at the expense of coal and oil. The range of decreased natural gas costs that was examined was not sufficient to drive compressed natural gas vehicles to penetrate the light-duty vehicle market, so there was limited interaction with the transportation sector.

Increasing natural gas costs by 35% or more appeared to drive oil use in electricity generation while at the same time resulting in decreased use of coal. Natural gas use decreased with cost, although the decrease was comparatively modest. These observations suggest that the increased natural gas cost may have triggered an emissions-related modeling tipping point that favors oil use over coal.

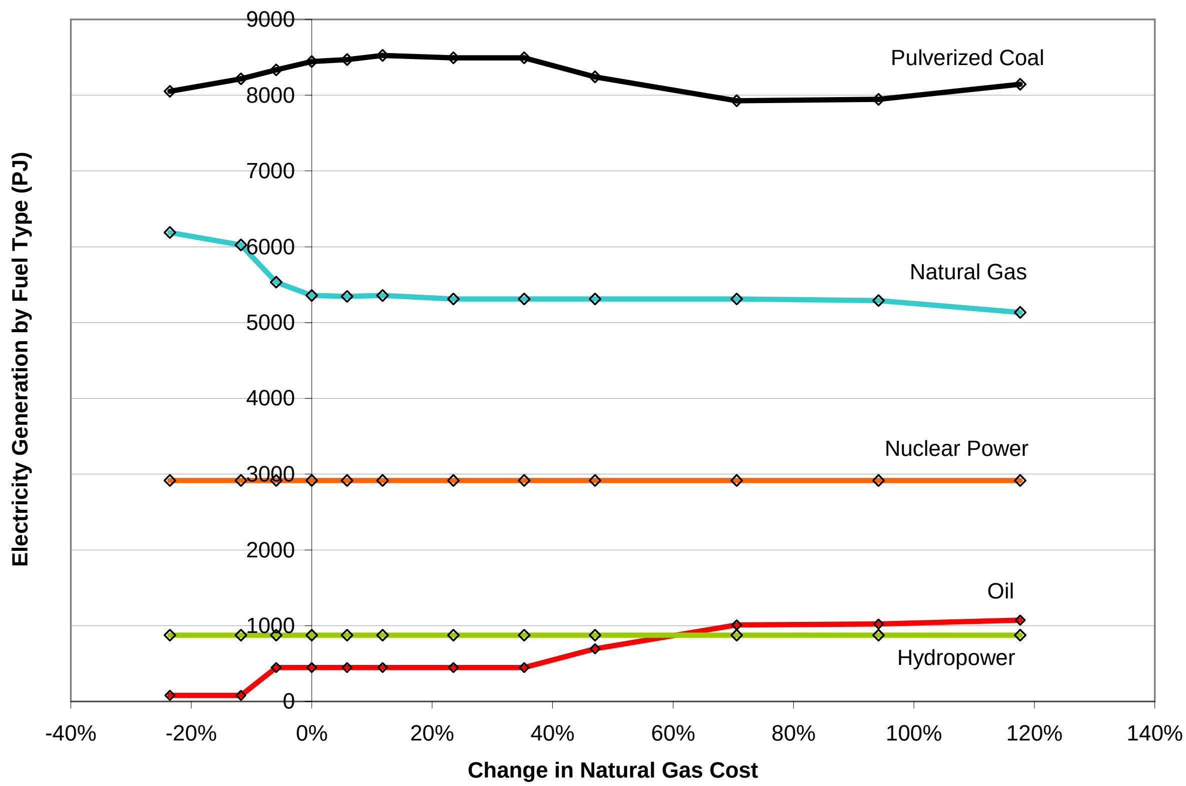


Figure 3.10: Impact of natural gas cost on electricity generation by fuel type.

Figure 3.11 shows that a decrease in the oil costs resulted in additional oil use in electricity generation, accompanied by decreases in natural gas and coal use. Coal use decreased to offset the loss of the low NO_X-producing natural gas technologies. Increased oil prices led to decreases in oil and coal use, with the corresponding demand met instead by natural gas. Coal decreases in this case were likely adopted to offset the loss of low-NO_X-producing oil technologies. Changes in coal use corroborate the hypothesized effect of the emissions constraint suggested in the discussion of Table 3.3 and Figure 3.4.

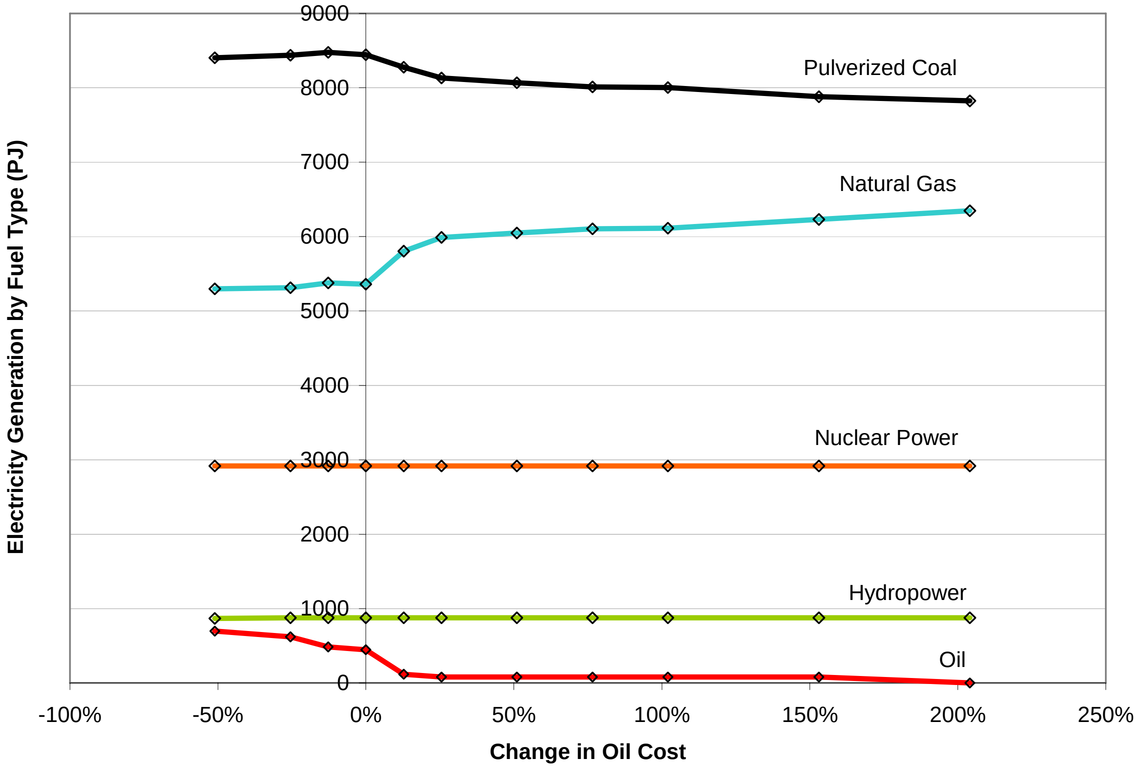


Figure 3.11: Impact of oil cost on electricity generation by fuel type.

Figure 3.12 shows the response of the electric sector to increased nuclear capacity. The primary fuel offset was coal, with only minor changes in natural gas use. Interestingly, the total amount of electricity generated, the sum across fuel types in the future, appears to increase with additional nuclear capacity. An examination of residential energy demands suggests that additional nuclear capacity resulted in fuel switching within that sector from natural gas and oil to electricity (e.g., to meet demands for home heating). Similar fuel switching may have occurred in the commercial and industrial sectors.

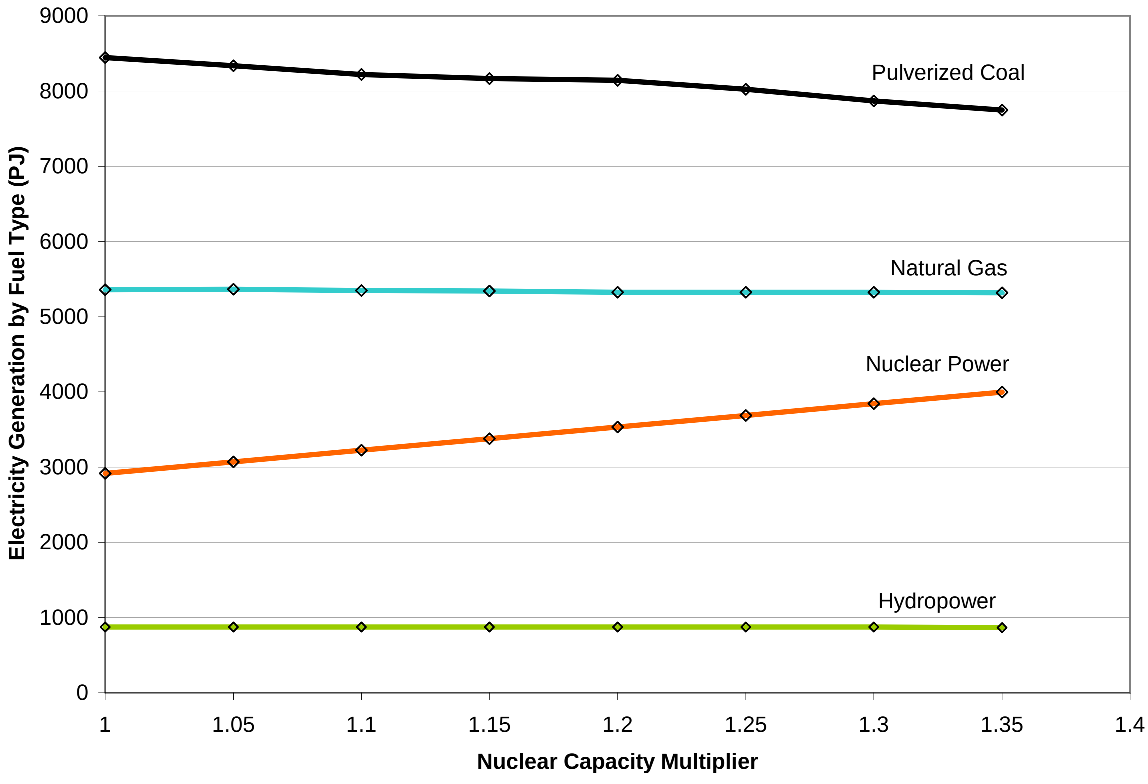


Figure 3.12: Impact of nuclear capacity on electricity generation by fuel type.

Increasing the hurdle rate from 0.05 to 0.25 had the effect of decreasing the uptake of new electricity generation technologies as shown in Figure 3.13. This decrease forces the cost of generating electricity to increase. The net result was a decrease in the use of oil, coal, and natural gas in electricity generation, as well as an overall decrease in the total amount of electricity generated. In response, MARKAL results suggested that the residential sector, commercial, and industrial sectors would experience some degree of fuel switching from electricity to other fuels in meeting demands such as space heating.

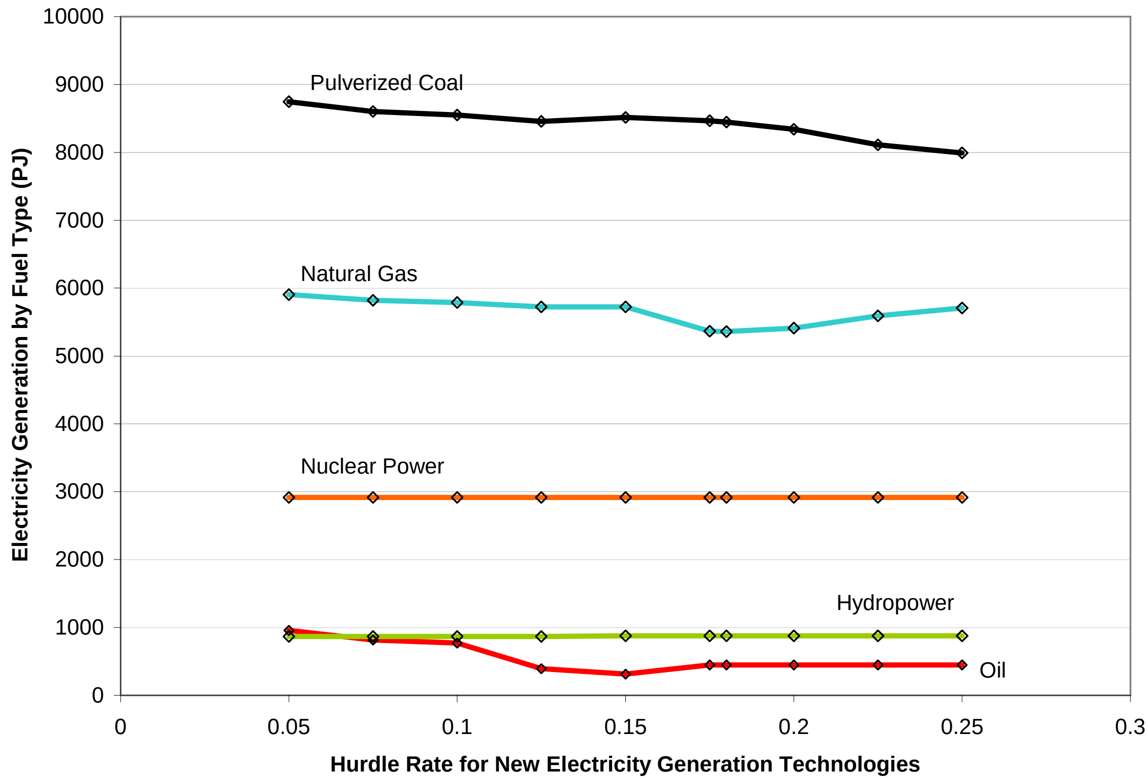


Figure 3.13: Impact of the new electricity generation technology hurdle rate on electricity generation by fuel type.

Figure 3.14 shows percent changes in CO_2 emissions from the electric sector in response to each of the four inputs. This is a different type of parametric sensitivity graph that shows the responses to parametric changes in more than one input on an output.

The results suggest that nuclear power capacity had the most direct impact on CO_2 emissions from the electric sector. A 35% increase in nuclear capacity yielded less than a 6% reduction in CO_2, however. Oil cost had a similar impact with respect to magnitude of CO_2 response.

The overall magnitude of changes in electric sector CO_2 emissions is less than might be expected. One of the primary reasons for the moderate level of these changes is that the renewable technologies with negligible CO_2 emissions are not sufficiently economically competitive that they are able to offset large amounts of fossil fuel usage. Instead, the primary response of the electric generation system to changing inputs is fuel switching from one fossil fuel to another. This has some implications on CO_2 emissions, as reflected in the small changes observed.

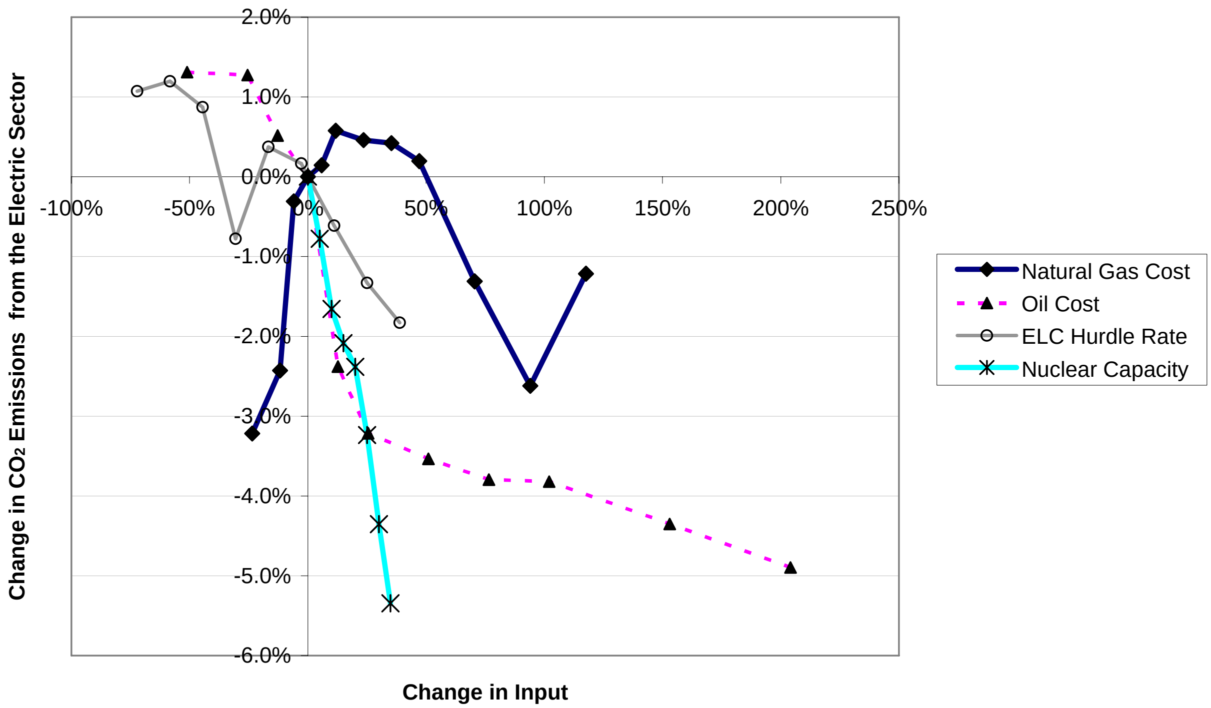


Figure 3.14: Changes in CO_2 emissions from the electric sector in response to changes in inputs.

In Figure 3.15, the system-wide impacts of parametric changes to each input on CO_2 emissions are shown. The functions observed are similar to those in Figure 3.14, although the overall magnitude of CO_2 changes is less, ranging from approximately +1% to -2.75%.

Sensitivity diagrams for electric sector NO_X and SO_2 emissions are not shown here. The electric sector NO_X and SO_2 emissions limits were binding in all runs. System-wide impacts were therefore largely dependent on the transportation sector.

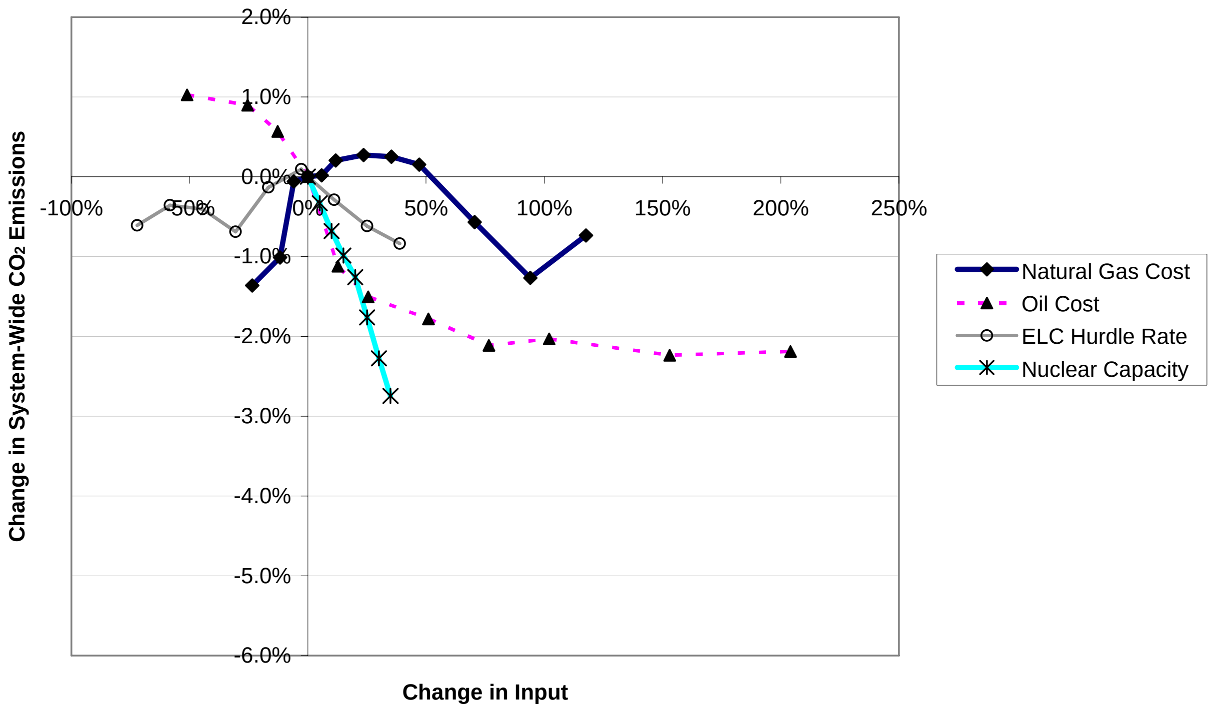


Figure 3.15: Changes in system-wide CO_2 emissions in response to changes in inputs.

Figure 3.16 shows the changes in net imports. Increased natural gas costs had the greatest impact on increasing reliance on imports, with a 100% increase in natural gas costs resulting in approximately a 17% increase in imports. The impact of oil costs on net imports was considerably less, reaching a maximum decrease in imports of about 5%, corresponding to a 150% increase in oil costs.

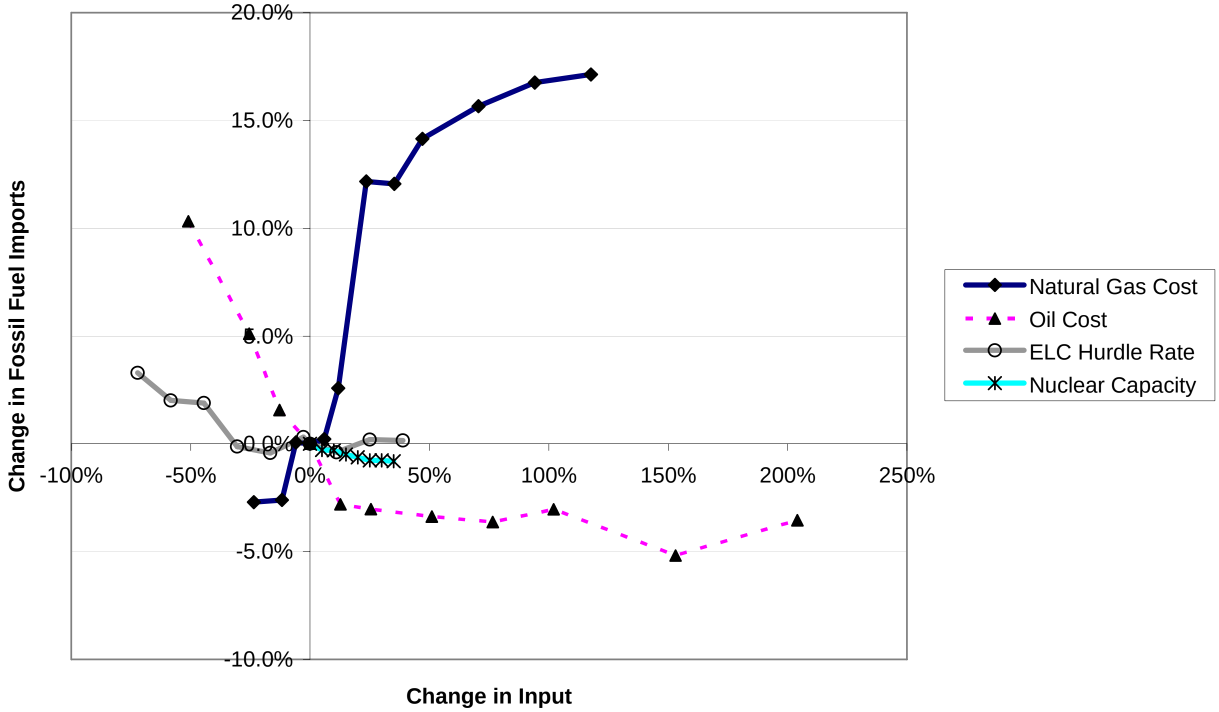


Figure 3.16: Changes in net imports in response to changes in inputs.

3.7 Summary of Observations from Sensitivity Analysis

The combination of correlation coefficients, normalized multiple linear regression, and parametric analysis of the BAU case provides considerable insight into the inner-workings of the MARKAL model and the response of the model to alternative input assumptions. In most cases, the results of these analyses confirmed expected behavior in the model. Additionally, the results provided insight into the complicated response of the system to criteria pollutant emission limits. In this subsection, we summarize many of the key observations from the sensitivity analysis.

Much of the EPANMD electric sector's behavior appears to be influenced by whether specific technologies and fuels meet base or peak load electricity demands. The predominant base load technologies are coal-fired power plants and nuclear power plants. Coal is the most competitive, and has the largest market share.

Natural gas- and oil-fueled technologies are used to meet peak electricity demands. Both fuels experience some cross-sector interactions with the transportation sector because natural gas and refined oil products can be used within vehicles. While there was some evidence of cross-sector interactions, these were largely of secondary importance to in-sector technology and fuel competition.

The electric sector emissions constraints have interesting effects on the electric generation mix. For example, when natural gas became more expensive and gas technology utilization decreased, use of coal also decreased. This behavior, which may at first seem counter-intuitive, is explained by the response of the system to the electric sector NO_X constraint. Since coal technologies had higher NO_X emissions than natural gas technologies, and since NO_X constraints on electric generation were binding, the model opted to replace natural gas with oil. Oil combustion also leads to greater NO_X emissions than that from natural gas, thought it is less than coal. Some coal was therefore displaced by oil. This fuel-switching and related technology change had implications on CO_2 emissions as well.

The electric sector NO_X constraint also affects the model's response to increased nuclear capacity. By introducing electricity generation capacity that does not have NO_X emissions, coal-fired power plant emissions are less constrained in meeting the electric sector NO_X constraint. In response, the fraction of coal-fired plants projected to make use of NO_X controls, such as selective catalytic reduction, decreases. The same behavior can be expected from increased electricity generation from low- or zero-NO_X renewables, such as solar or hydropower.

The electricity generation hurdle rate has an additional impact on future-year energy sector technologies. Increasing this rate effectively makes it more difficult for new, more efficient technologies to penetrate the electricity generation market. This difficulty, in turn, has the effect of increasing the marginal peak electricity price, increasing CO_2 emissions from electricity generation, and decreasing the penetration of renewables. Thus, addressing hesitancy to adopt new technologies through some approaches for hedging risk may yield a more efficient electricity generation system.

Imports of fossil fuels are correlated with the use of oil in electricity generation, but inversely correlated with natural gas use, reflecting that much of the natural gas demand is being met by domestic supplies in the model. Cross-sector fuel switching resulting from changes in natural gas and oil consumption in the transportation sector may also have an impact, but further analysis is needed to characterize this behavior.

Finally, changes in system-wide CO_2 emissions in response to variation in model inputs were minor, with decreases of less than 3% observed. This output is influenced by the inability of low-CO_2 emitting technologies, and in particular, renewables, to achieve high market penetrations. When these technologies do penetrate, the potential reductions in CO_2 emissions are often offset by increased use of coal and other fossil fuels, made possible via the room under the NO_X limit created by the renewables.

Sensitivity analysis such as is presented here has been a useful component of the MARKAL model database development and quality assurance. By identifying key drivers and interactions, sensitivity analysis facilitates an understanding of how the model responds to alternative input assumptions which, in turn, aids model refinements.

Section 4
The Future Role of Nuclear Energy in the U.S.

4.1 Introduction

With all nations facing enormous challenges related to energy security, sustainability and environmental quality, nuclear power will likely play an increasingly important role in the future. In particular, the life-cycle emissions of criteria pollutants and greenhouse gases from nuclear power plants are significantly lower than from conventional fossil-fueled plants, renewing interest in nuclear power as a low emissions source of electric power. In order for nuclear power to emerge as a key future technology, four basic challenges must be met: cost, safety, proliferation prevention, and waste management (Ansolabehere et al., 2003). While acknowledging significant challenges related to the latter three items, this analysis focuses on an engineering-economic assessment of future nuclear power in the U.S.

This section focuses on the potential role of nuclear power in the U.S. electric sector over the next 30 years by analyzing results from the U.S. EPA National MARKAL Database model (EPANMD). The section first describes the implementation of conventional and advanced nuclear technologies in the EPANMD. In the next subsection, modeling results are presented and analyzed. Finally, implications of the penetration of nuclear technologies on the emissions from the power sector are drawn.

4.2 Nuclear Technology Representation in MARKAL

In the EPANMD, all nuclear technologies draw on a single uranium supply curve. The uranium supply curve is based on estimates of global uranium reserves and the cost of extraction (OECD/IAEA, 2002). Because the energy density (energy per unit weight) of uranium is high, transport costs were ignored.

The nuclear fuel cycles included in EPANMD were determined by careful consideration of the nuclear technologies most likely to be deployed in the U.S. over the next three decades. The analysis considers the following technologies: light water reactors operating on a once-through fuel cycle, mixed-oxide reactors, heavy water reactors, fast breeder reactors, and high temperature gas-cooled reactors. Although not a comprehensive list of nuclear technologies, they represent the broad technical thrusts in the nuclear industry.

In an increasingly competitive world of deregulated electricity generation markets, other things being equal, systems with lower upfront costs and shorter construction times are likely to be preferred by investors over those with higher upfront costs and longer construction times. Light water reactors (LWRs) operating on a once-through fuel cycle (no reprocessing) currently have the lowest cost among commercially available reactors. LWRs have been widely adopted globally and still currently serve roughly 20 percent of U.S. electricity demand.

Heavy water reactor technology typically calls for larger plants with higher construction and capital costs, as compared to light water reactor plants. Moreover, the large amount of heavy water (deuterium) required to run these plants also necessitates significant infrastructure investments. A heavy water reactor's key advantage is its ability to use natural uranium, as compared to enriched uranium required by light water reactors. However, the demand-supply equilibrium is such that most analysts expect enough enriched uranium to be available at reasonable price for at least the next half-century. As a result, heavy water reactors are not included in the EPANMD.

Enough supplies of uranium exist to build and operate roughly 1000 reactors in a once-through LWR nuclear fuel cycle. If new uranium resources do not become available and existing resources are depleted at a rapid pace, then breeder reactors may emerge as a viable option to meet long-term energy supply goals. Breeder reactors not only fission uranium, but also convert fertile materials (primarily U^{238} and Th^{232}) into fissile products (primarily Pu^{239} and U^{233}). Breeder reactors are designed to produce more fissile material than they fission. Breeder reactors are not an economically attractive option in the wake of prevailing enriched uranium prices, at least in the short-term. Therefore, we did not include breeder reactors in the EPANMD.

In the U.S., LWRs are likely to remain the dominant nuclear technology because there is significant experience with design, construction and operation of these plants. However, MOX (mixed oxide) reactors were also included in the model, since it is at least plausible that plutonium recycling would be considered in the future, despite the high costs and risks of proliferation. MOX fuel is created by first extracting the fissionable uranium and plutonium from the spent LWR fuel in a process known as PUREX (plutonium and uranium extraction). The resultant fuel must be blended with depleted uranium (a byproduct of the uranium enrichment process) to obtain the correct proportion of fissionable material in the fuel.

Costs and performance characteristics for LWRs were drawn from Ansolabehere et al. (2003) and DOE (2001). It should be noted that the Ansolabehere et al. (2003) cost estimates for MOX recycling are significantly higher than European estimates (Ansolabehere et al., 2003) and should be interpreted as conservative. Table 4.1 below shows the cost associated with the light water reactor fuel cycle used in EPANMD.

Table 4.1: Cost and performance estimates for LWRs used in EPANMD.

	Existing LWRs	**LWRs in 2010**	**MOX Reactors**
Capital Cost* ($/kW)	N/A	1440	2000
O&M Cost ($/kWh)	0.0125	0.005	0.0077
Burnup (MWd/kg IHM)	50	50	40
Capacity Factor (%)	85	90	85
Efficiency (%)	33	36	33
Fuel Cost ($/kWh)	0.0051	0.0051	0.022
Lifetime (years)	40	40	40
Average Cost ($/kWh)	0.018	0.036	0.070
Data Source	NEI, 2003	DOE, 2001	Ansolabehere et al., 2003

*The levelized costs for new plants are calculated with a 15% discount rate, representing a private investor's expected rate of return.

Figure 4.1 presents a schematic diagram of the LWR fuel cycle in the EPANMD. The enrichment step includes the cost for uranium ore purchase, conversion, enrichment, fabrication, and storage and disposal of nuclear waste. Note that spent uranium can be reprocessed and fissioned in a MOX (mixed oxide) reactor.

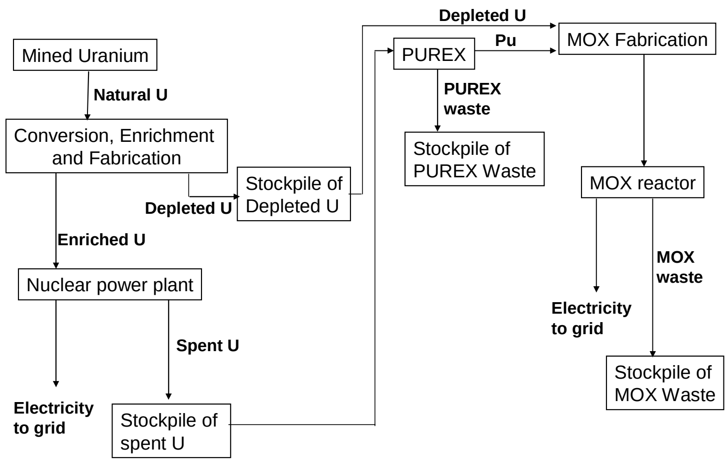


Figure 4.1: Schematic diagram of the light water reactor (LWR) fuel cycle in the EPANMD.

LWRs have several technical drawbacks that have limited their deployment, particularly in the U.S. Construction of the reactor vessel and associated fuel handling equipment is materials-intensive and requires large capital outlays. To defray the cost, LWRs exploit economies of scale: LWR plants are typically 1 GW or larger and usually take 10 years to approve and build. From a finance perspective, investors may be unwilling to bear the risk of ordering a plant that will not go online for many years, by which time others may have added new capacity in the same region. Although large nuclear plants provide relatively low per kWh cost, they have the drawback of exceeding demand growth in smaller-demand networks.

In addition, the low thermal efficiency (approximately 33%) and burnup (50 GWd/TIHM) of LWRs create a significant amount of radioactive waste that requires storage and disposal. The ultimate disposition of spent uranium from LWRs presents a serious technical challenge and a public policy concern. Finally, LWRs rely on active safety systems and human judgment and intervention to prevent core meltdowns, which can fail, as evidenced by the accident at the Three Mile Island nuclear facility outside of Harrisburg, Pennsylvania.

High temperature gas-cooled reactors (HTGRs) address many of the shortcomings of LWRs and are therefore included in the EPANMD. HTGRs are built in modular units ranging from 100-300 MWe, making nuclear a feasible option in smaller markets. The smaller size and modular design can also allay investor concerns about long construction times and the associated financial risk. In addition, HTGRs have higher burnup and thermal efficiency, resulting in a proportional reduction in spent fuel. Finally, HTGRs incorporate a passive safety design, such that heat generated during fission can be thermally conducted to the ground without resulting in a core meltdown.

In order to dissipate heat passively through the ground, HTGRs must have a smaller core density than LWRs, so multiple HTGR units are required to compete with a single LWR. At first glance, it would seem that HTGRs would be prohibitively expensive because the design does not take advantage of the same economies of scale as LWRs. HTGR designers are depending on a different economic scaling law that will make HTGRs competitive with LWRs: factory manufacturing of modules, shorter construction schedules, and sequential completion of units (1 year apart). Because HTGRs are currently in the demonstration stage, this economic strategy remains unproven.

There are two main competing HTGR designs: the Pebble Bed Modular Reactor (PBMR) and the Gas Turbine – Modular Helium Reactor (GT-MHR). A common feature of these two designs is uranium oxide particles coated with pyrolytic carbon to contain the fission products. In the PBMR design, the fuel particles are embedded in carbon spheres roughly 2.5 inches in diameter, which allows the continuous removal and reloading of fuel spheres without shutting down the reactor. Also, both the PBMR and GT-MHR use helium as a coolant and run modified combustion turbines directly on the high temperature helium. A schematic diagram of the HTGR fuel cycle without recycling is shown in Figure 4.2. Note that while in practice it is possible to extract enriched uranium and plutonium from the spent fuel particles, it is prohibitively expensive at present.

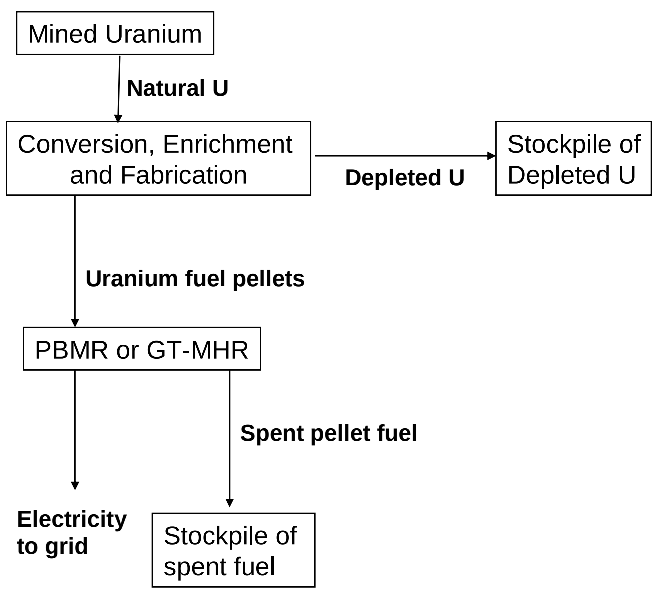


Figure 4.2: Schematic diagram of the high temperature gas-cooled reactor (HTGR) fuel cycle in the EPANMD.

Because there has been no commercial development of HTGRs, the cost estimates used in EPANMD are speculative. The capital costs represent nth-of-a-kind estimates, which assume the units are being mass produced. The speculative nature of the estimates and the nth-of-a-kind cost assumptions make the characterizations of HTGRs in the EPANMD optimistic (see Table 4.2).

Table 4.2: Cost and performance estimates used in EPANMD for HTGRs (advanced nuclear).

	PBMR	**GT-MHR**
Capital Cost* ($/kW)	1250	1122
O&M Cost ($/kWh)	0.0025	0.0036
Burnup (MWd/kg IHM)	80	112
Capacity Factor (%)	95	90
Efficiency (%)	40	48
Fuel Cost ($/kWh)	0.005	0.0077
Lifetime (years)	60	60
Average Cost ($/kWh)	0.03	0.033
Data Source	DOE, 2001	DOE, 2001

* The levelized costs for new plants are calculated with a 15% discount rate, representing a private investor's expected rate of return.

4.3 MARKAL Analysis

The EPANMD includes the following nuclear technologies: LWRs, MOX plants, PBMRs, and GT-MHRs (the latter two being the high-temperature gas-cooled reactors). In the results that follow, the LWR and MOX plants are grouped together and presented as "conventional nuclear" and the PBMR and GT-MHR are grouped together and presented as "advanced nuclear".

Growth Rates

The choice of a nuclear growth rate constraint is a key assumption, as it prevents MARKAL from building an unrealistic amount of nuclear capacity. Ideally, the growth rate constraint would be based on the amount of capacity installed in the previous time period, but MARKAL does not provide the capability to define a capacity-dependent growth rate constraint. Instead, MARKAL allows the specification of growth rate constraints by time period only. The maximum growth rate decreases in later time periods under the assumption that nuclear capacity will grow at a slower pace as the nuclear capacity base grows larger. In addition, another growth parameter was used to allow a small increment of capacity to be added above the upper bound growth constraint. For conventional LWRs, the incremental capacity allowance is 4 GW–representing roughly four new plants–and the capacity allowance is 3 GW for advanced nuclear–representing roughly 15 new units. This incremental capacity provides an upper bound on the nuclear capacity the first year it enters the model, and allows the 3 – 4 GW addition over and above the specified growth rate in all subsequent periods. Growth constraint specifications are shown in Table 4.3. Conventional nuclear can first enter in 2010, and 4 GW max can be built. Note that these growth rates apply to each individual technology; there are two advanced and two conventional nuclear technologies.

Table 4.3: Annual maximum growth rates (%) by model time period and incremental capacity (GW) allowable over the growth rate.

	Incremental GW	2015	2020	2025	2030
Conventional	4	25	25	18	12
Advanced	3	0	25	25	18

While the choice of future growth constraints is somewhat arbitrary, the growth constraints shown in Table 4.3 are plausible. From the inception of Eisenhower's Atoms for Peace Program in the early 1950s to the mid-1980s when the last U.S. nuclear units came online, roughly 100 GW of nuclear capacity was built (EIA, 2003). This benchmark indicates the U.S. built 100 GW over 30 years, or roughly 3 GW/yr assuming linear capacity additions. With the upper bound growth constraints in Table 4.3, the maximum conventional nuclear capacity would be approximately 130 GW by 2030. Likewise, the maximum advanced nuclear capacity would be approximately 80 GW by 2030. Though this upper bound on growth allows for the unprecedented expansion of nuclear, a mature nuclear industry and improved technology make such growth feasible.

Model Results

Electricity production is shown in Figure 4.3 when EPANMD is run with both conventional and advanced nuclear technologies. The results include 16 GW of new conventional nuclear and 50 GW of new advanced nuclear.

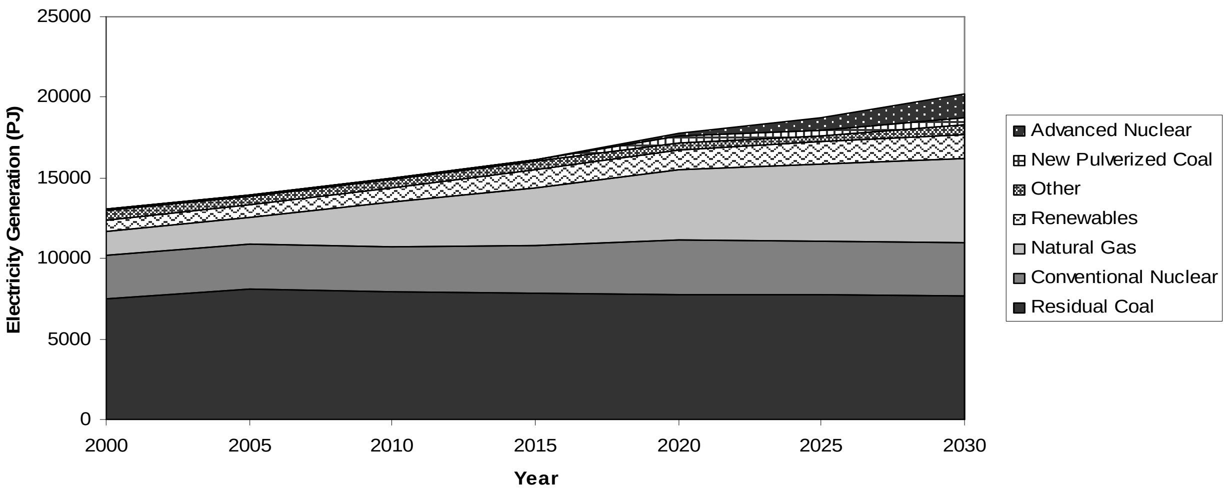


Figure 4.3: Electricity generation in a baseline run of EPANMD with both conventional and advanced nuclear technologies available.

The new nuclear capacity did not reach the upper bound growth constraints shown in Table 4.3. In 2030, nuclear power accounts for 17.4% of the electricity generated, which maintains the current amount of nuclear power on a relative share basis. Much of the growth in electricity demand over the model time horizon was met by new combined-cycle natural gas (248.8 GW).

Because fossil fuel prices are a key future determinant of electric sector technology, parametric analysis of natural gas and coal prices was performed to observe the impact on nuclear power installations. Figures 4.4 and 4.5 show the change in the nuclear share as coal and gas prices are increased, respectively. Doubling the coal price (+2 \$/GJ) only increases the nuclear share by approximately 1% (Figure 4.4). While doubling the natural gas price (+5 \$/GJ) increases the share of nuclear by approximately 5% (Figure 4.5).

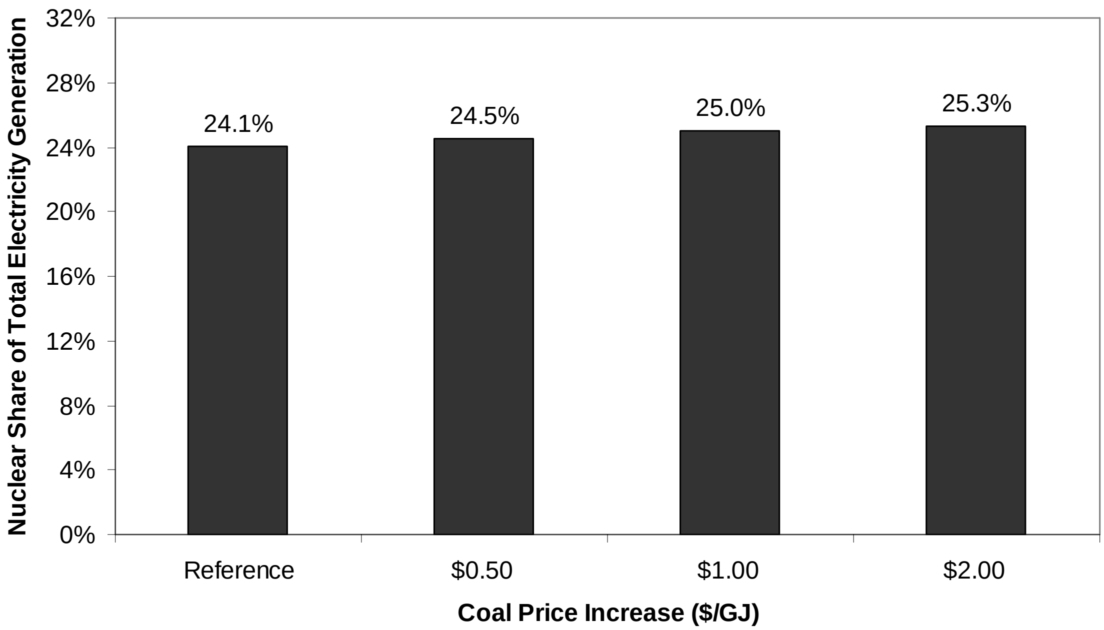


Figure 4.4: Change in the 2030 nuclear share of total electricity production as coal price is increased parametrically.

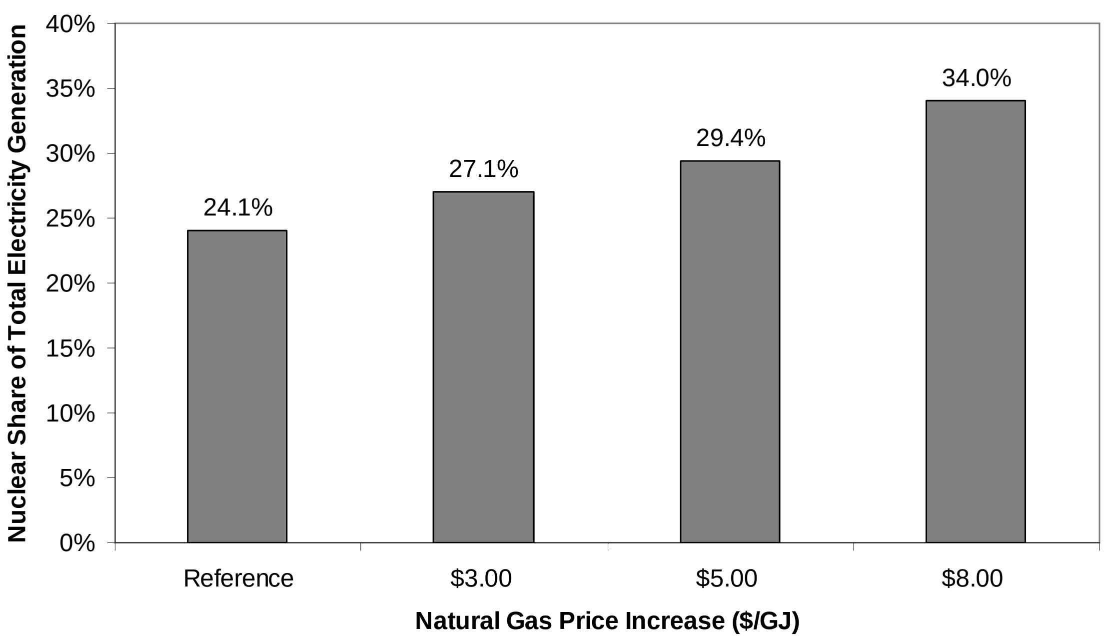


Figure 4.5: Change in the 2030 nuclear share of total electricity production as natural gas price is increased parametrically.

Figures 4.4 and 4.5 demonstrate that nuclear power can provide a limited hedge against high fossil fuel prices in the electric sector. An additional scenario was run that included both an 8 $/GJ markup on natural gas and 2 $/GJ markup on coal prices to examine the synergistic effect on nuclear capacity. The result was a nuclear share of total electricity that was approximately 37% (approximately 3% more than an 8 $/GJ mark up on natural gas alone). The high natural gas and coal prices together did not push conventional nuclear to its growth limits, which would allow nuclear to achieve a maximum share of approximately 45% in 2030. Because EPANMD supply curves for coal and natural gas are based on EIA's Annual Energy Outlook, which employs very conservative assumptions regarding fuel prices, the range of costs tested in the sensitivity analysis above is plausible.

Surprisingly, the availability of nuclear has no effect on SO_2 and NO_X emissions. In all scenarios, the Clean Air Act emission constraints on electric sector emissions are in effect. Because air pollutant emissions are driven largely by pre-existing coal plants, the emissions constraints require much of this capacity to be retrofitted to reduce emissions. However, new capacity is largely SO_2 and NO_X emissions free: nuclear has zero operating emissions, new pulverized coal capacity includes FGD for SO_2 control and SCR for NO_X control that eliminate more than 90% of emissions, and natural gas turbines have low emissions. Because the incremental cost to retrofit existing coal plants is low, the pre-existing coal plants are retrofitted in all model scenarios and continue to run over the entire model time horizon. The availability of new nuclear capacity only affects the construction of new plants, which has little effect on air pollutant emissions.

Figure 4.6 shows that CO_2 emissions are also minimally impacted. The "baseline" scenario assumes no new nuclear capacity additions and the "advanced + conventional nuclear" scenario allows the addition of both LWRs and HTGRs. Between 2000 and 2030, 66 GW of new nuclear (conventional + advanced) is built. By 2030, new nuclear capacity results in only a 7% reduction in electric sector carbon emissions compared with a model scenario that does not allow new nuclear capacity to be built. This modest emissions benefit is partly explained by the fact that the availability of nuclear results in 20 GW of total additional generating capacity over the constant nuclear case, presumably because some service demands can be met more cost-effectively by electricity when nuclear is a supply option. The nuclear capacity additions have a negligible effect on carbon emissions in sectors other than electric; the modest electric sector emissions benefit is largely obscured in the system-wide carbon emissions.

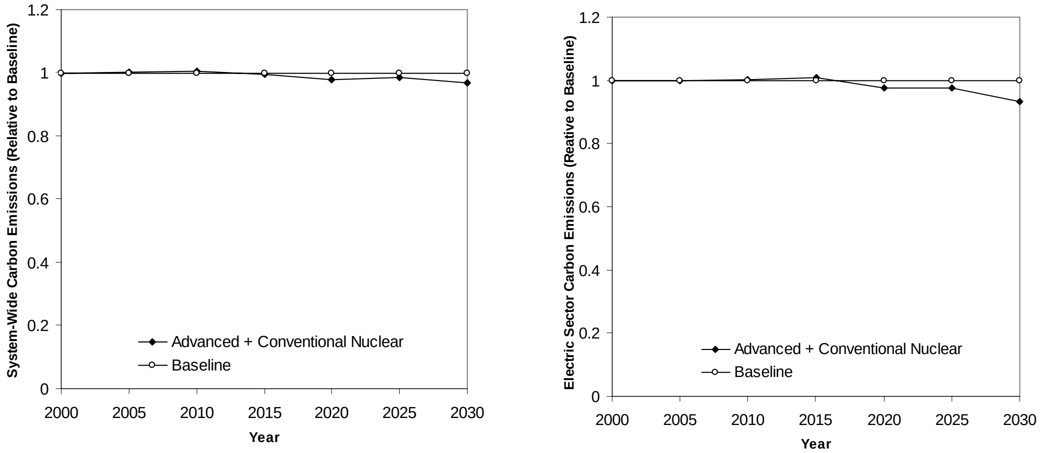


Figure 4.6: System-wide (left) and electric sector (right) CO_2 emissions relative to baseline scenario.

In the analyses above, nuclear was unable to gain a significant market share and, as a result, emission reductions were minimal. This is a consequence of the CAA restrictions being tighter than the beneficial role nuclear played in generating electricity. Circumstances that depart even further from BAU model assumptions, however, could provide stronger incentive for new nuclear investment.

Advanced nuclear generation technologies, for instance, may play a larger role when electric sector CO_2 emission trajectories depart significantly from BAU assumptions (see Section 2). Alternate (non-BAU) carbon trajectories, though they represent a realistic stimulus for new nuclear investment, primarily offer a means to flex the EPA MARKAL model and facilitate a more convincing examination of how this investment might impact criteria pollutant emissions. The trajectories used in this analysis include: (1) electric sector carbon emissions limited to 1995 levels from the BAU scenario (Section 2) starting in 2015, (2) electric sector carbon emissions limited to 80% of 1995 levels from 2015 on, and (3) electric sector carbon emissions limited to 50% of 1995 levels from 2015 on. Note that these low carbon scenarios apply only to the electric sector, not system-wide.

These carbon trajectory scenarios are deliberately arbitrary in that they do not reflect known projections, proposed policy, or a preferred carbon emissions profile. The non-BAU trajectories merely serve to force a signal—in this case, the adoption of advanced nuclear generating technologies. One, of course, could constrain the model to produce a certain fraction of its electricity from new nuclear capacity and examine the effects on criteria pollutant emissions. Doing so, however, would be equivalent to using MARKAL as a calculator and would fail to take advantage of its strength as an energy *systems* model. The non-BAU carbon trajectories provide an incentive not only for new nuclear investment, but also for the addition of competing technologies like natural gas and renewables. It such this competition that will drive criteria pollutant emissions in any scenario, and accounting for these emergent system effects provides a more realistic picture of the corresponding air quality implications.

Figure 4.7 presents electric sector technology penetrations for the three alternative carbon trajectories. In general, pre-existing coal capacity is forced off-line, and combined-cycle natural gas turbines appear to be the most effective technological response in carbon limited scenarios. However, nuclear plays an increasingly important role as the carbon trajectory departs from BAU results. Even with high costs for the MOX fuel cycle, MOX plants play a role in the lowest carbon scenario. Figure 4.8 illustrates how much conventional and advanced nuclear capacity was built compared with the capacity limits set by the growth constraints. The low carbon trajectories are the same as shown in Figure 4.7. Note that the growth in advanced nuclear is steeper because the capacity of both PBMR and GT-MHR have been added together.

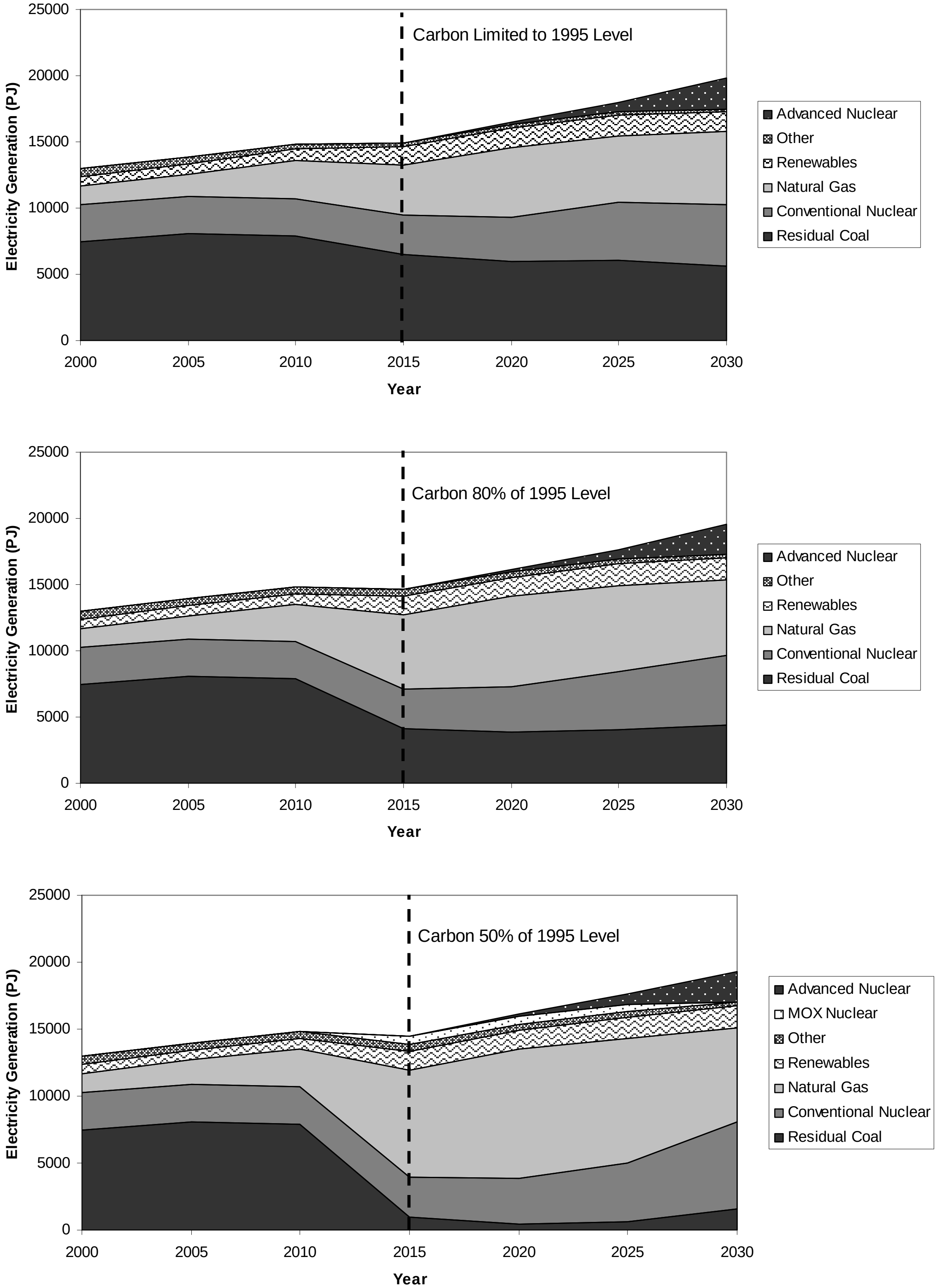


Figure 4.7: Electricity generation by technology from non-BAU carbon trajectories and both conventional and advanced nuclear technologies are available.

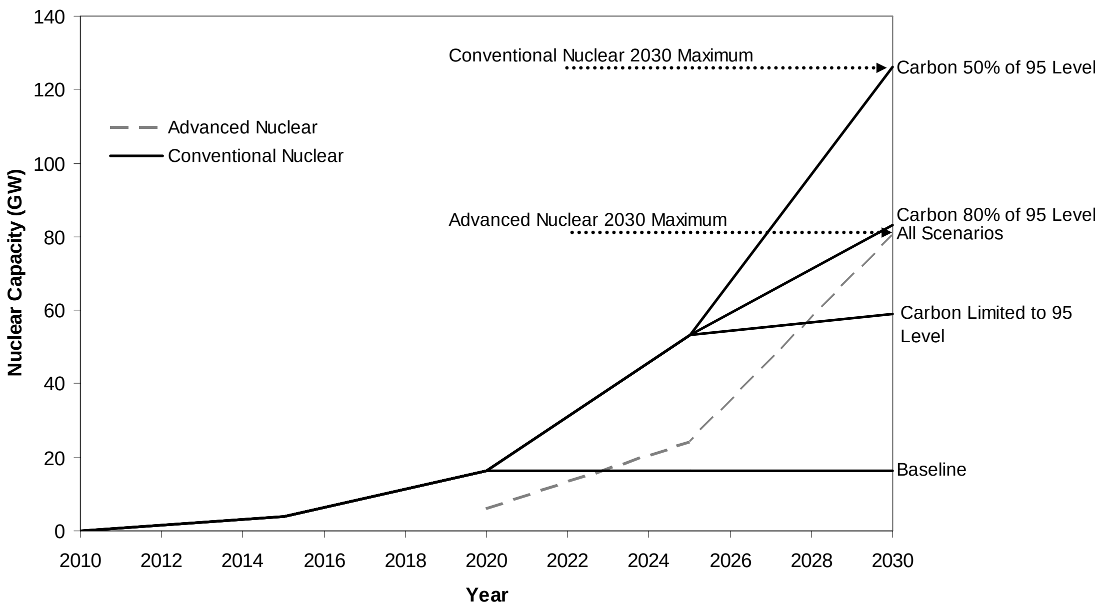


Figure 4.8: Conventional and advanced nuclear capacity over time, compared with the maximum capacity allowed by the growth rate constraints.

Figure 4.8 demonstrates that advanced nuclear (HTGRs) are a compelling option for the future. In all scenarios, the model builds the maximum allowable advanced nuclear capacity. While the costs for HTGRs in the model are highly speculative, the results can be interpreted as prescriptive: if developers can meet the currently projected nth-of-a-kind cost targets for HTGRs, they are likely to play an important role in the future U.S. electricity system. Conventional nuclear only hits the growth constraint limit in the scenario with the tightest carbon trajectory. The higher capital costs for LWRs put them at an economic disadvantage relative to HTGRs.

An interesting result is how advanced technologies in the U.S. electricity sector do have ancillary benefits for air quality. Figure 4.9 presents SO_2 and NO_X emissions under the three non-BAU carbon trajectories shown in Figure 4.7.

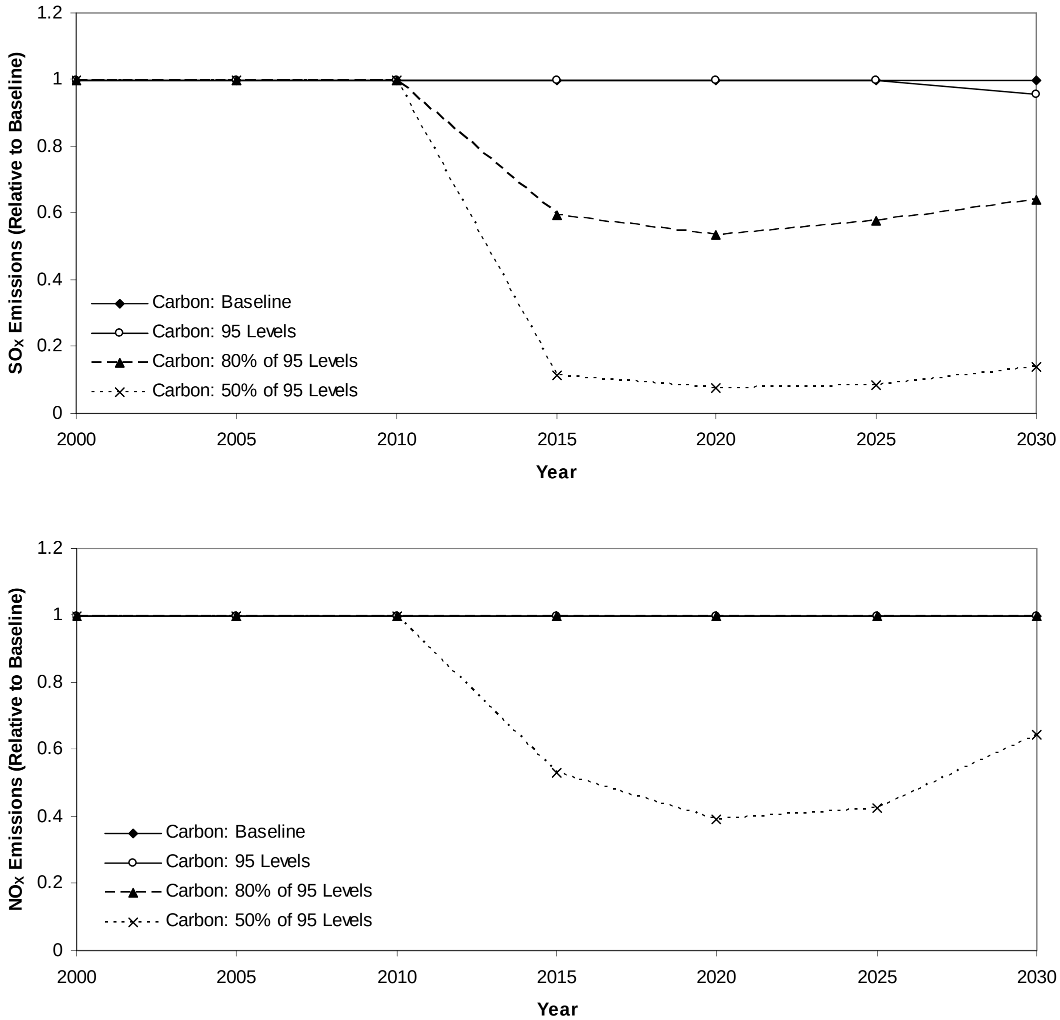


Figure 4.9: SO_2 (top) and NO_X (bottom) emissions relative to the baseline scenario under the low carbon scenarios presented in Figure 4.7.

The alternative CO_2 trajectories have a significant impact on SO_2 emissions, with deep reductions in emissions under the two scenarios that depart furthest from BAU assumptions. The NO_X emissions constraint, however, is binding except under the 80 and 50 percent trajectory, when 87 percent of the pre-existing coal-derived electricity is replaced by technologies with lower emissions. As a result, low carbon trajectories in the electric sector will only reduce NO_X emissions when most of the pre-existing coal capacity is displaced

Suppose there is no limit to the rate at which nuclear capacity can grow. Figure 4.10 demonstrates the mix of generation sources (with nuclear growth rate constraints removed) under a carbon trajectory that is 20% below 1990 levels from 2015 to 2030. In this case, advanced nuclear plays a central role in electricity production after 2020.

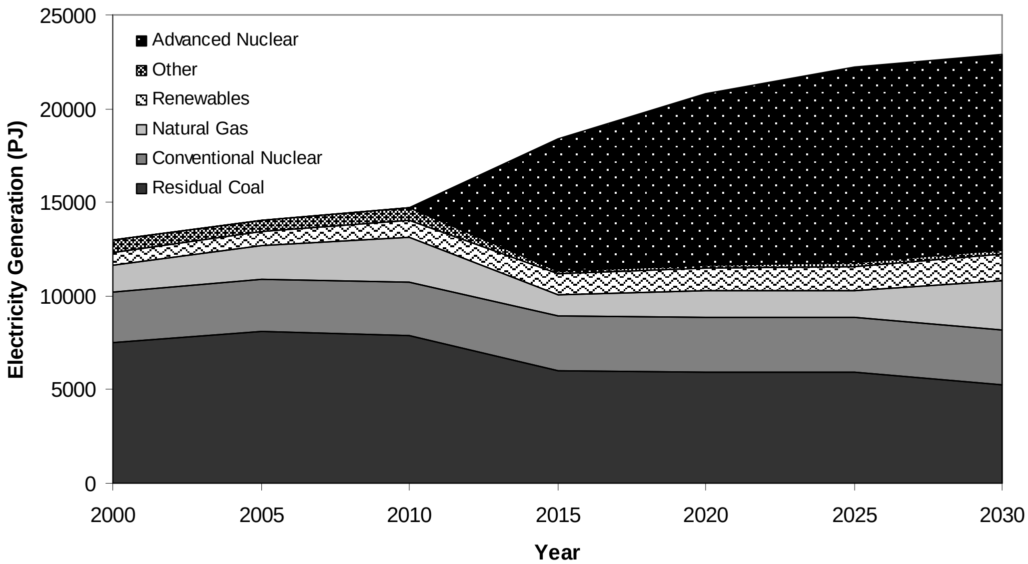


Figure 4.10: Electricity generation by generation source with a carbon trajectory reflecting 80 percent of 1995 levels from 2015 to 2030.

The new advanced nuclear capacity (GW) added by time period is shown below in Table 4.4. Interestingly, the model chooses to build 235 GW of new advanced nuclear capacity between 2010 and 2015, which not only meets growing demand but also displaces a portion of the electricity production from existing pulverized coal plants and natural gas turbines. This is an enormous amount of nuclear power that represents fully 25% of currently installed U.S. capacity. Even under the most optimistic scenarios for the deployment of HTGRs, this amount of new capacity would be implausible to deploy only one decade from now, in particular because of limited manufacturing capacity. After the massive addition of nuclear in 2015; however, the capacity additions of advanced nuclear are more plausible. This initial massive investment in nuclear followed by smaller additions in later time periods reflects the carbon limit, which is imposed in 2015 and remains constant thereafter.

Table 4.4: GW of advanced nuclear added by model time period.

Year	**2015**	**2020**	**2025**	**2030**
Capacity (GW)	235	71	44	0.1

4.4 Conclusions

The MARKAL scenario results presented in this section offer important insights into the role that nuclear technology can play in the U.S. electricity system over the next three decades. First, if high temperature gas-cooled reactors (HTGRs) can be constructed at the currently projected costs, they would be preferable to higher cost light water reactors (LWRs) and could plausibly play a large role in the future.

Increased costs for natural gas and coal do not have a significant impact on the penetration of nuclear. As a result, nuclear only provides a modestly effective hedge against high fossil fuel prices in the electric sector, at least over the price range explored here. These modest penetration levels contribute to meeting the electric sector's CAA limits for SO_2 and NO_x.

Although both conventional and advanced nuclear are economical in the base case, nuclear generation only has a modest impact on system-wide carbon emissions. When the electric sector follows non-BAU carbon trajectories, new nuclear capacity plays a more significant role and leads to SO_2 and NO_x reductions below CAA constraints. In all cases, the model prefers advanced nuclear (the high temperature gas-cooled reactors) to conventional nuclear (the light water and MOX reactors). The issues governing this preference include whether HTGR developers can meet the model's optimistic nth-of-a-kind cost assumptions and how rapidly units can be manufactured and deployed over the next few decades.

Section 5

The Air Quality Implications of Carbon Capture and Sequestration in U.S. Electric Markets

With its abundant coal reserves, the U.S. has built an electric power infrastructure dominated by coal-fired generation. Coal plants produce roughly half the nation's electricity, with natural gas and nuclear plants each contributing nearly twenty percent and renewables making up the difference (EIA, 2006a). Given the long-lived nature of this infrastructure and the lack of an economically-competitive substitute technology, the nation's dependence on coal is unlikely to cease. The U.S. Department of Energy (DOE) is therefore assessing technological options to reduce the environmental impacts of coal plants. Technologies included in this assessment include coal gasification and carbon capture and sequestration (CCS). By itself, coal gasification would nearly eliminate atmospheric SO_2, NO_x, and Hg emissions; integrated with CCS, the combined technology could also make potentially significant reductions in electric sector CO_2 emissions, should the need to do so arise (NETL, 2005). Integrated gasification-CCS technologies could also provide the technological underpinnings of a future hydrogen economy (FutureGen Industrial Alliance, 2006).

This section examines the air quality benefits of CCS in an energy systems context. While climate concerns would drive the adoption of CCS, the technology could yield important air quality benefits—benefits that would depend on the rate at which CCS units enter the market and the technologies they displace. In addition, CCS would compete with an expanded use of natural gas, nuclear power, and renewable energy sources. A systems level assessment is needed to examine how these routes to electric sector CO_2 reduction interact, how this interaction affects the economic attractiveness of CCS, and how these dynamics collectively impact criteria pollutant emissions.

This section begins to meet the need for a comprehensive assessment. The first two subsections define CCS as examined here, list its prominent advantages and disadvantages, briefly describe the current state of the technology, and discuss its implementation in the U.S. EPA National MARKAL model. The following subsection presents the analysis by identifying scenarios in which CCS technologies enter, given business as usual assumptions about competing technologies. Section 6 of this report broadens the assessment to look at how CCS might compete with other supply-side abatement alternatives under more optimistic scenarios about the latter. An evaluation of CCS relative to end-use efficiency improvements is left for future work.

The assessment in this section focuses on CCS *from an energy system perspective* and seeks to identify scenarios—ranges of CCS costs and performance factors, for instance—that lead to its adoption. The section examines generic classes of CCS power generation units and does not evaluate the merits of particular CCS technologies. The analysis also concentrates on CO_2 capture and considers only the aggregate cost of sequestration—not the many other significant issues surrounding underground injection of the gas. Finally, the analysis does not evaluate or propose policies related to CO_2 control. CCS technologies, of course, will not be adopted without the need to reduce electric sector CO_2 emissions. The analytical approach employed here examines how CCS technologies fare relative to other emission abatement options *given* a

CO_2 emission trajectory expressed as some percentage of business as usual projections in order to examine the impact on air quality.

5.1 CCS Technology Background

CCS provides a means of reducing electric sector CO_2 emissions. In this context, CO_2 capture works with any power generation unit utilizing coal or natural gas as its primary fuel, and may take place before or after combustion. Sequestration occurs by injecting the captured CO_2 into a suitable geological formation after transportation – most likely by pipeline – from the plant. Deep saline aquifers, as well as active and depleted oil and gas reservoirs are potential sequestration sites. CO_2 may also be captured from industrial processes, and "CO_2 sequestration" is often used to refer to the uptake of atmospheric CO_2 in biomass and soils. Neither of these options is considered here. Recent publications from the International Energy Agency (IEA, 2004) and the Intergovernmental Panel on Climate Change (IPCC, 2005) provide up-to-date and comprehensive background information on CCS.

The value of CCS lies in its potential to ease the world's dependence on an energy infrastructure dominated by fossil fuel consumption (Johnson and Keith, 2004). The long life and slow turnover of this infrastructure and the current unavailability of an economic substitute support the continued use of fossil energy—especially coal for power generation. CCS is compatible with the electric sector as it exists today. On the generation side, power plants with CO_2 capture (new or retrofit) would have the same capacity as their conventional counterparts, and follow similar dispatch rules. Construction and management expertise at the plant level would also transfer. Beyond the plant, the electric power distribution network would remain the same and electricity consumers would experience no change in how they use energy (though it would likely cost more). Finally, the utilities and other energy companies that currently supply electricity would continue to do so, and the ability to exploit niche markets and take advantage of synergies (e.g., selling captured CO_2 for enhanced oil recovery) might increase their competitive advantage.

CCS, of course, is not without significant drawbacks. Although a potentially valuable transition technology, CCS is an "end-of-pipe" solution that does not address the more fundamental need to move away from an energy system reliant on carbon-intensive—and, in the case of petroleum and natural gas, ultimately limited—fossil energy resources. In addition, successful adoption of CCS could ease the pressure to develop more sustainable energy alternatives, and resources invested in CCS technologies are resources not invested in renewable options (i.e., an opportunity cost). CO_2 capture also requires considerable energy, which increases both the cost of generating electricity and the amount of CO_2 produced per kWh. As a result, while a sudden release of sequestered CO_2 near a low-lying inhabited area poses the vivid risk of asphyxiation, a more general failure to contain CO_2 could—in the extreme—result in higher atmospheric concentrations of the greenhouse gas than would have been the case if CCS had not been pursued. These disadvantages, along with technological uncertainties and the need to address important issues related to regulation, liability, long-term monitoring, and public acceptance, pose obstacles to the adoption of CCS (Palmgren, et al., 2004; Wilson, 2004).

In terms of promise, however, the potential benefits of CCS are seen as offsetting its disadvantages, and development of the technology has consequently progressed to the demonstration phase. The DOE's *FutureGen Initiative*, for instance, is the most visible U.S. attempt to develop a large-scale power production facility with CO_2 capture and sequestration—one that will also produce H_2 and serve as a joint industry-government sponsored research testbed within the coming decade (FutureGen Industrial Alliance, 2006). Utilities are also beginning to evaluate the merits of designing new, retrofit compatible coal-fired or coal gasification power generation units should they eventually decide to pursue CO_2 capture (EPRI, 2005). On the sequestration side, several ventures are operational, and three of these—in Norway, Canada (with CO_2 captured in the U.S.), and Algeria—have achieved injection rates close to 1 $MtCO_2$ per year (IPCC, 2005). These examples provide an indication of the resources being devoted to CCS-related projects, and are only a reflection of the growing level of international research activities (see IPCC, 2005, for a review).

The initial success of CCS will depend on the integration of disparate, but largely mature, component technologies, and scaling the resulting system up to a level able to handle the amount of CO_2 generated annually by a typical power plant (roughly 1 $MtCO_2$/year for a 500 MW unit). Niche applications—in which an electric power plant with capture would provide a supply of CO_2 for enhanced oil recovery (EOR), for instance—might help lower initial costs and lead to learning-related cost reductions and performance improvements. Long-term success will rest on improvements in capture technology, development of a legal framework to govern sequestration, and public acceptance. This section focuses on the first of these three requirements (capture), though the other two are likely to be equally significant.

CO_2 capture as currently envisioned may take place along one of three general routes (Figure 5.1). The first of these is equivalent to traditional "smoke stack" controls for SO_2 and NO_X and involves post-combustion separation of CO_2 from the remaining flue gases. Applicable to both coal-steam and natural gas combustion turbines, this approach would likely be the preferred means of retrofitting existing power generation units (short of a complete repowering, as discussed below). Existing post-combustion capture technology relies on chemical absorption of CO_2 using a monoethanolamine solvent—a mature industrial process that has provided CO_2 for use in food, beverage, and chemical production since the 1950s. Amine separation can remove up to 95% of the CO_2 from a gas stream, though removal efficiencies in the 80% range would likely be more common in practice. Table 5.1 (below) summarizes cost and performance data.

Several technical issues, however, create disincentives to the use of post-combustion capture processes relying on amine separation. Solvent regeneration, steam requirements, and the need to compress the captured CO_2 (which constitutes only 3-15% of power plant flue gas by volume), for instance, impose an energy penalty on the order of 10-40% of the unit's output. In addition, the amine separation process requires the use of scrubbers to remove SO_2, NO_X, particulate matter, and other flue gas impurities prior to CO_2 capture. Scale is yet another issue, with contemporary commercial amine capture systems more than an order of magnitude smaller than that required for a typical coal-fired power plant. Amine-based capture is therefore unlikely to be economically competitive relative to other electric sector CO_2 emission abatement alternatives. Post-combustion CO_2 capture from air-fired power plants may be viable if an amine substitute becomes available. Research is currently focusing on absorption using novel solvents (both liquid and solid), the development of adsorption processes, and the use of membranes

(IPCC, 2005). The advantages of finding a "cheap" retrofit option for existing coal-fired power plants provide incentives.

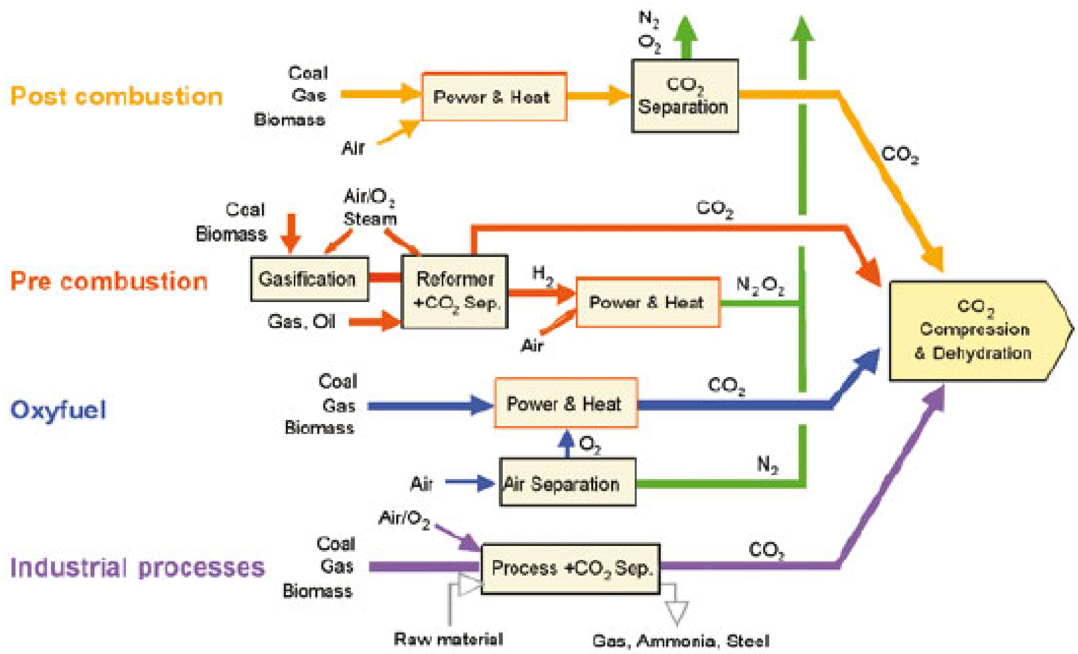


Figure 5.1: Schematic of the three generic routes to carbon capture and sequestration; industrial process are shown, but not included in this analysis; Source: IPCC (2005)

Amine-based CO_2 capture is conceptually similar to post-combustion controls for SO_2 and NO_X; except for the energy penalty, operation of a power plant would not "look" different with flue gas CO_2 capture. So-called oxy-fuel processes offer a second post-combustion route to CO_2 capture, but one that would require more significant changes in power plant design. Rather than combusting coal or natural gas in air, an oxy-fuel system would use a mix of pure O_2 and recycled flue gas CO_2. As combustion in O_2 produces mainly CO_2 (at least 80% of flue gas volume) and water vapor, capture would require little more than drying the flue gas and compressing the CO_2. An oxy-fuel system would therefore capture nearly all CO_2 produced (again, see Table 5.1 for cost and performance data). Small-scale oxy-fuel combustion processes have found industrial applications, but do not exist as integrated systems at the scale needed for power generation. Like amine separation, an oxy-fuel power plant would operate at a lower efficiency than its conventional counterpart, with the O_2 production process (a mature technology) responsible for much of the added energy requirement. Applied to existing power plants, oxy-fuel conversion is considered to be a repowering option (i.e., replacing a plant's core energy generating technologies), rather than a retrofit modification.

The last generic route to electric sector CO_2 capture differs from the first two by separating the carbon from the fuel stream prior to combustion. The approach to separation most likely to shape the design of new power plants with CO_2 control, pre-combustion capture is a mature process that the H_2, synthetic fuel, and chemical industries use routinely. The process begins with either steam reforming or partial oxidation of natural gas, or gasification of coal, to produce

H_2 and CO (other byproducts—such as H_2S from coal gasification—need to be removed). A water gas shift reaction then produces additional H_2 while converting CO into a high pressure CO_2 stream. The higher pressure simplifies the CO_2 capture process (which is typically accomplished via physical absorption) and reduces its energy requirements, improving overall system efficiency. The H_2 is available for use in a combined turbine and steam cycle power generation unit, though it could also be used in a fuel cell to produce power or sold as a transportation fuel or industrial feedstock. Coal-based IGCC (integrated gasification combined-cycle) plants with CO_2 capture are the most frequently mentioned pre-combustion CCS technology in the literature, both for new plant construction and existing unit repowering. IGCC technologies (with or without capture), however, are currently limited to high-ranked coals. Like oxy-fuel conversion, pre-combustion CO_2 capture applied to existing power plants would involve significant repowering rather than a retrofit add-on.

Table 5.1 compares cost and performance estimates for new technologies representing the three generic routes to CO_2 capture described above, and contrasts these with their non-CCS counterparts. With the benefit of research and learning-by-doing, newly-built plants with CO_2 capture in 2020 are expected to achieve costs and efficiencies similar to their non-capture equivalents today (IPCC, 2005).

Table 5.1: Estimated cost and performance ranges from the literature for new CCS technologies as summarized by the IPCC (2005).

Technology	Capital Cost ($/kW)	Cost of Electricity ($/MWh)	Thermal Efficiency (% LHV)	CO_2 Capture Efficiency
Post-Combustion				
PC*	1161-1486	43-52	41-45	n/a
PC + CCS	1894-2578	62-86	30-35	85-90
Pre-Combustion				
IGCC	1169-1565	41-61	38-47	n/a
IGCC + CCS	1414-2270	54-79	31-40	85-91
NGCC**	515-724	31-50	55-58	n/a
NGCC + CCS	909-1261	43-72	47-50	85-90
Oxyfuel				
Oxyfuel	1260-1500	44-45	37-44	n/a
Oxyfuel + CCS	1857-2853	58-83	25-35	Insufficient data

*PC = pulverized coal
**NGCC= natural gas combined-cycle

The costs of retrofitting existing plants, in contrast, are highly uncertain and are more likely to be site-specific. The IPCC, for instance, notes that "[t]here has not yet been any systematic comparison of the feasibility and cost of alternative retrofit and repowering options for existing plants" (IPCC, 2005, p. 344). The energy penalty associated with amine-based post-combustion retrofits renders this option economically unattractive; oxy-fuel or pre-combustion repowering of coal units, however, may be worthwhile as the end result is essentially a new—and likely larger—plant without the obstacles associated with developing a greenfield site. A further distinction lies between retrofitting or repowering plants that exist today, and designing new non-capture power plants for future conversion. The cost of the latter, of course, will be cheaper and more predictable.

The analysis that follows focuses on the penetration of electric sector CO_2 capture technologies. The sequestration component of CCS enters the assessment only as a cost, which consists of CO_2 transport, injection, and monitoring components. The first two elements involve mature technologies and processes with which the oil and gas industries have considerable experience. Land-based pipeline transport as currently practiced, for instance, costs 1-5 \$/tCO_2 per 100 km. Applied to CCS, future injection cost estimates range more widely—from 0.5 to 8.0 \$/tCO_2, depending on the site—with the need to monitor CO_2 containment adding 0.1 to 0.3 \$/tCO_2 (IPCC, 2005). Note that sequestration capacity is not likely to pose a problem. Deep saline aquifers (i.e., below 800 m) alone may hold 1000 to 10,000 GtCO_2—several orders of magnitude greater than yearly global CO_2 emissions (which are on the order of 25 GtCO_2/year; IEA, 2004). Sequestration in depleted oil and gas reservoirs provides another option and, as noted, the ability to sell CO_2 for enhanced oil recovery (EOR) might provide a profitable and early niche market—and a route to achieving learning-by-doing technology improvements. EOR operations in the U.S., for instance, have historically paid 10-16 \$/tCO_2, depending on oil and gas prices (IEA, 2004).

While the cost of CO_2 sequestration is likely to be significantly less than that of capture, the institutional uncertainties associated with injection and storage are greater. The necessary legal frameworks (both domestic and international) are not in place, risk management trade-offs are in need of resolution, and public acceptance of large-scale underground CO_2 storage remains untested. In addition, site-specific factors will play a much greater role in determining sequestration (and, hence, emission abatement) potential in a given region. The future of CCS rests as much on resolving institutional issues such as these as its does on solving technical problems (Wilson, Johnson, and Keith, 2003).

Integrated assessments, however, suggest that CO_2 capture technologies could sequester nearly 50% of projected global CO_2 emissions by mid-century at a cost ranging between 25 and 50 \$/tCO_2 (IEA, 2004; IPCC, 2005). While CO_2 capture would add at least 2-3 cents/kWh to electricity prices today, this premium would likely drop by half over a few decades. CCS could therefore be an important element in a portfolio of electric sector emission abatement options. The remainder of this section examines the place of CCS in this portfolio from an air quality standpoint.

5.2 Implementation of CCS in the U.S. EPA National MARKAL Model

The analytical approach adopted in the remainder of this section examines generic classes of electric sector CCS technologies (e.g., IGCC with CO_2 capture) rather than specific proposed designs (e.g., a Texaco oxygen-blown, quench-based gasifier). Reference values from the range of studies surveyed by the IPCC (2005) and summarized in Table 5.1 provide baseline cost and performance data for these technology representations—a starting point to more informative uncertainty analyses. Anderson and Newell (2004), IEA (2004), Johnson and Keith (2004), and EIA (2006b) provide additional data. Table 5.2 lists the CCS-related technologies included in the U.S. EPA National MARKAL model database, and provides details about their specifications. EPA (Shay,et al., 2006) provides documentation on the base MARKAL model. All CCS technologies become available in the 2015 model period, have a 40 year useful life, and share an 18 percent investment hurdle rate.

Table 5.2: CCS technology parameters as implemented in the EPANMD. All figures were converted into common units from their actual MARKAL values.

Technology	Capital Cost ($/kW)	Variable Operating Cost ($/kWh)	Fixed Operating Cost ($/kW)	Thermal Efficiency (%)	CO_2 Capture Efficiency (%)
Retrofits					
Existing Coal Retrofit	1414	0.0093	26.24	65	85
New PC Retrofit	1345	0.0085	21.84	70	85
IGCC Retrofit	966	0.0045	8.99	80	90
NGCC Retrofit	763	0.0022	5.77	80	85
New Integrated Technologies					
IGCC+CCS	1873	0.0040	41.44	40.0	90
NGCC+CCS	1021	0.0027	18.12	42.9	90

The retrofit parameterization requires a few words of explanation. First, the incremental retrofit costs are higher than published estimates for amine-based systems (see, e.g., Simbeck and McDonald, 2001; IPCC, 2005) to account for the fact that the MARKAL model employs base plant (i.e., conventional PC, IGCC, and NGCC capacity) cost figures that are more optimistic than the retrofit studies typically assume. To prevent MARKAL from immediately retrofitting newly-built conventional capacity instead of building a new integrated capture plant, the model adopts retrofit cost parameters that ensure that the combined investment and operating costs of retrofit capacity (base plant costs + retrofit costs) are at least as great as those of the corresponding integrated capture plant. Second, the retrofit "efficiency" is perhaps better interpreted as an energy penalty (i.e., a base plant output derating). The inverse of the retrofit efficiency (expressed as a decimal fraction) is the increase in input energy required per unit of retrofit energy output. The corresponding energy penalty is then this increase divided by 1 plus itself [energy penalty = increase/(1+increase)]. Finally, since all retrofits sit in the fuel chain leading into the base plant, the MARKAL database adjusts the retrofit parameters to account for the base plant efficiency.

Note that the model does not include new integrated PC capture plants or an oxyfuel option. These technologies are not sufficiently different from new IGCC capture units to be meaningfully distinct in MARKAL. IGCC is generally seen as the least-cost coal-fired capture alternative and the model therefore adopts the label for its new coal CCS technology; investment in IGCC capture technologies could therefore represent one of several technologies.

In keeping with this aggregate technology representation and the analytical focus on supply-side CO_2 abatement options, the augmented model uses a single figure (28 $/tC, or approximately 7.5 $/t$CO_2$) to represent the cost of CO_2 transport, injection, and long-term monitoring. This value reflects the upper end of published estimates, and assumes that geological injection sites are located within 300 km of all central station power generating units (IPCC, 2005).

This generic representation of CCS technologies is compatible with the level of detail characterizing other electric sector power generation technologies in the EPA National MARKAL database (e.g., three model plants represent all existing U.S. coal-fired units). This level of detail is also compatible with both the uncertainty inherent in CCS technologies, the nature of a linear programming optimization model like MARKAL, and the scenario-based analytical strategy that guides the following assessment.

Choices made in modeling carbon capture retrofits provide a useful illustration of this point. As discussed, CO_2 capture using solvent absorption is a mature industrial process. The costs and performance issues associated with retrofitting existing coal-fired power plants at the scale necessary to make a significant reduction in electric sector emissions, however, are uncertain. Contemporary amine-based technologies would impose such a significant energy penalty that alternative technologies (e.g., membranes) would likely be needed for the post-combustion retrofit option to become economically feasible. All retrofit technologies would be subject to uncertain learning, and site-specific details such as the space available for the capture equipment would drive installation costs. Differences in the specifications of proposed retrofit technologies easily fall within the range of this uncertainty, but an optimization model like MARKAL will always pick the technological option with the lowest overall costs, inflating the apparent significance of that technology and possibly leading to rapid and unstable period-to-period shifts in favored options. Modeling identifiable but marginally different retrofit schemes would therefore produce meaningless and potentially misleading results. (Note that these schemes may have significantly different *technological* potential; unless they also have substantially different costs and efficiencies, however, they essentially look the same within MARKAL. The most one could do is lower a technology's availability to reflect decreased reliability. Radically different retrofit designs, of course, should be modeled independently.)

Given that small differences in parameter values often lack practical significance in a modeling context like this, a reasonable alternative would look only at broad technology classes and then use sensitivity analysis around their reference parameter values to identify ranges of these values that influence results. MARKAL characterizes CCS retrofits, for instance, by their costs and energy penalties. One could use parametric sensitivity analysis to examine how variations in model retrofit specifications affect retrofit adoption, and then trace "successful" parameter combinations back to specific retrofit designs. The difference in approach between modeling a suite of technologies and using sensitivity analysis in conjunction with a representative example may seem subtle, but the generic strategy—for reasons described above—is more defensible for this type of analysis and is consequently employed below.

5.3 CCS Results and Analysis

The remainder of this section does for CCS what the previous section did for nuclear power generating technologies. Building on the business as usual (BAU) scenario results (Section 2), the analysis examines the extent to which CCS technologies contribute to meeting electricity demand and its impact on air quality under the same set of alternative electric sector CO_2 trajectories that framed the nuclear assessment. It is worth repeating that these non-BAU trajectories are arbitrary and merely a modeling device used to stimulate CCS investment, and do not represent policy or endorse a particular carbon emissions profile.

Outcomes of interest from this analysis include: patterns of investment in CCS technologies and their electricity output; the balance between new, integrated CCS units and existing capacity retrofits; the share of coal- and natural gas-fueled CCS technologies; the competition between coal-to-gas fuel switching and CCS; and ultimately the impact of CCS penetration on electric sector criteria pollutant emissions. Scenario drivers within the CO_2 trajectory framework include variations in CCS parameters (especially costs and efficiencies), natural gas prices, and sequestration costs. This analysis assumes BAU nuclear and renewable generating capacity. Section 6 allows new nuclear and renewable technologies into the model and concludes the report with a look at the competition between these alternatives to fossil-fuel based power generation and CCS.

Tables 5.3 and 5.4 summarize electricity generation by technology class and new capacity investment, respectively, for a model run with CCS technologies (as described above) and an electric sector CO_2 trajectory that holds emissions constant at 1995 levels from 2015 on (approximately 2.4 Gt CO_2 per five-year period). Figure 5.2 illustrates how different technologies contribute to meeting increasing power demand over time, and Figure 5.3 shows the impact of CCS technology penetration on electric sector CO_2, SO_2, and NO_X emissions, as well as economy-wide CO_2 output. Compared to the non-CCS BAU analysis (Section 2), coal-fired generation actually increases slightly at the expense of gas, with new integrated IGCC+CCS capacity providing the CO_2 emissions reduction. Neither NGCC units with CO_2 capture nor retrofits of any types enter. Note that the level of investment in conventional gas technologies is not significantly different from the non-CCS base case.

Table 5.3: Baseline CCS scenario electric power generation (in PJ/period) by technology class and time.

Technology	Electricity Generation (PJ/period)						
	2000	2005	2010	2015	2020	2025	2030
Nuclear	2734	2788	2831	2874	2916	2916	2916
Existing Coal	7485	8095	7900	6452	6225	5972	5558
New PC	0	64	64	64	64	64	64
IGCC	0	0	0	0	0	0	0
Existing Coal Retrofit	0	0	0	0	0	0	0
New PC Retrofit	0	0	0	0	0	0	0
IGCC Retrofit	0	0	0	0	0	0	0
IGCC+CCS	0	0	0	674	2012	2250	3201
Gas	1424	1661	2676	3767	4402	5003	5713
NGCC Retrofit	0	0	0	0	0	0	0
NGCC+CCS	0	0	0	0	0	0	0
Renewables	702	781	827	1369	1445	1583	1685
Other*	550	481	439	132	146	143	220

*Other includes natural gas-fired microturbines (distributed generation), diesel combustion engines, and generation from municipal solid waste and landfill gas.

Understanding the results involves analyzing the relationship between the ways in which different technologies meet electricity demand, air quality goals, and the need to recover capital investment. In general, coal-fired power plants have high capital requirements, but low operating costs relative to gas turbines (the latter due largely to differences in fuel costs). This cost difference, combined with dissimilar operating characteristics (i.e., coal plants are not simply "turned on"), explain why coal units typically supply baseload power, while natural gas units are especially suited for load-following during peak demand hours. Coal, of course, is the most carbon-intensive fossil fuel and baseload generation (to the extent that it is not met by nuclear plants) is therefore especially carbon intensive. Hence, CCS enters with coal (here, IGCC). This pattern also makes sense from a CCS investment standpoint. CO_2 capture is costly. If a utility invests in CCS technology, it will want to use that capacity to the limits of its availability (reliability), since the per kWh costs of the technology decline with increased power production. CCS therefore enters the dispatch order to meet baseload demand, while peaking units simply do not generate enough electricity to make CCS worthwhile (see Johnson and Keith, 2004).

Table 5.4: Baseline CCS scenario new capacity investment (in GW/period) by technology class.

Technology	New Capacity Investment (GW/period)						
	2000	2005	2010	2015	2020	2025	2030
Nuclear	0	0	0	0	0	0	0
Existing Coal	0	0	0	0	0	0	0
New PC	0	2	0	0	0	0	0
IGCC	0	0	0	0	0	0	0
Existing Coal Retrofit	0	0	0	0	0	0	0
New PC Retrofit	0	0	0	0	0	0	0
IGCC Retrofit	0	0	0	0	0	0	0
IGCC+CCS	0	0	0	25	50	9	35
Gas	38	77	0	98	43	31	32
NGCC Retrofit	0	0	0	0	0	0	0
NGCC+CCS	0	0	0	0	0	0	0
Renewables	0	9	1	7	4	5	6
Other	4	4	4	4	4	4	4

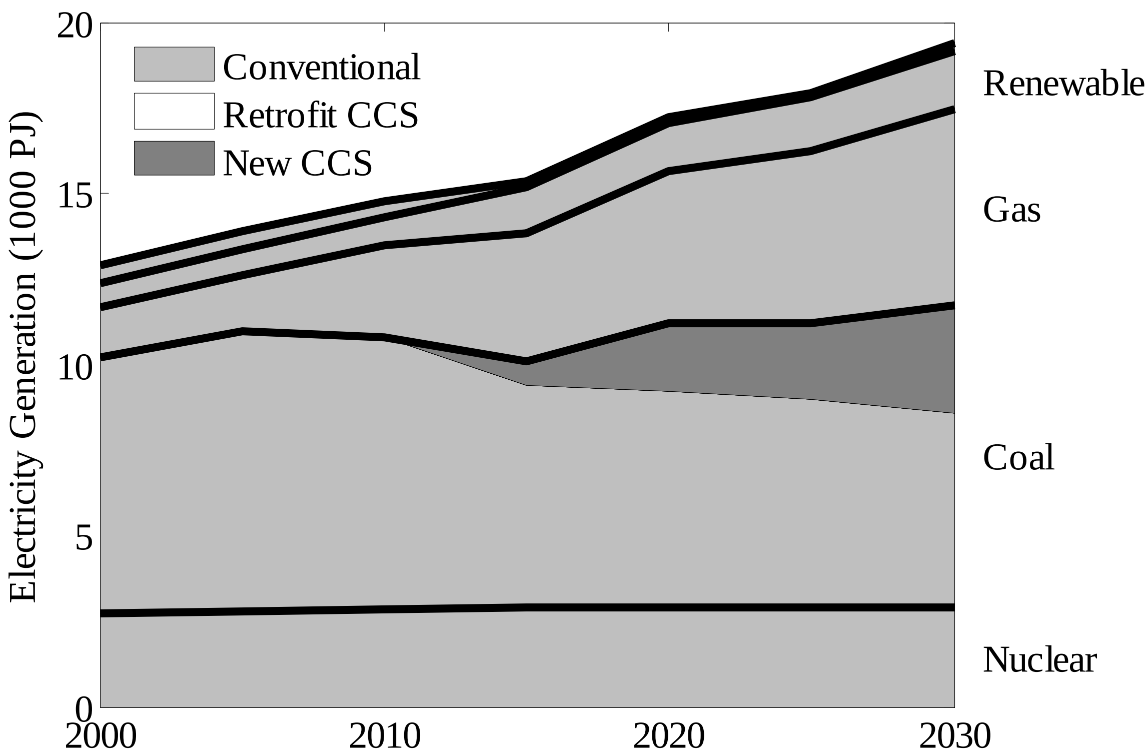


Figure 5.2: Electricity generation per-period by technology class for the baseline CCS scenario (electric sector CO_2 emissions held constant at 1995 levels from 2015 on, with no CCS growth constraints).

The emissions numbers (Figure 5.3) tell an interesting story. Electric sector CO_2 emissions decline to nearly two-thirds of their BAU levels by 2025, while system-wide carbon output decreases by about 10 percent. Electric sector NO_X emissions, however, remain essentially unchanged at their constrained BAU levels (which account for Clean Air Act mandated limits), while SO_2 declines roughly 20 percent for two periods before hitting its cap once again. The explanation for this behavior lies with the deployment of existing coal plant criteria pollutant control retrofits (FGD especially), which are used approximately 20 percent less in the CCS scenario. IGCC plants with CO_2 capture also reduce criteria pollutant emissions, easing the burden on coal plant retrofits to meet emission constraints.

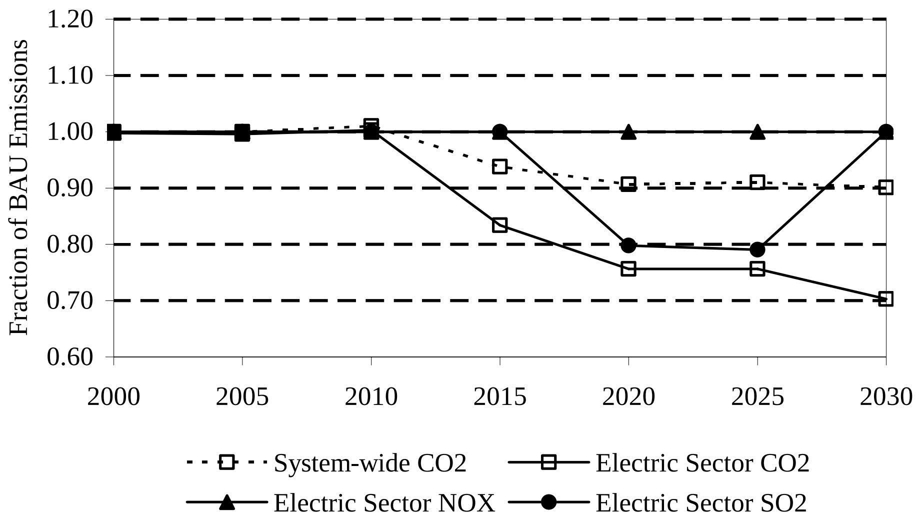


Figure 5.3: Electric sector CO_2, SO_2, and NO_X and economy-wide CO_2 emissions as a function of time for the baseline CCS scenario.

One objection to these results is the rate at which CCS investment takes place, starting in 2015 (Table 5.4). MARKAL, as a "perfect foresight" modeling framework, assumes the position of a rational decision maker with complete information about the future. The model thus determines the least-cost means of meeting demand for energy services over the entire time horizon, making all investment and operating decisions simultaneously. Actual investors do not have the luxury of clairvoyance, or necessarily the long-lead time represented here (20 years from 1995 to 2015), to pursue research and development and ready new technology (such as IGCC with CO_2 capture) for the market. Results would likely look different in a myopic model that made investment decisions on a period-by-period basis without consideration of future operating constraints. Adoption of novel technologies like IGCC would be more gradual, at least until reliability issues were resolved, sufficient learning occurred, and economies of scale were achieved.

Picking a growth rate, however, is difficult for the non-BAU world represented here. Achieving an emissions trajectory similar to the CCS scenario's would induce technology change in an unpredictable manner. With sufficient leadtime, levels of technology adoption as shown in Table 5.4 would not necessarily be unreasonable, though one might expect to see IGCC appearing gradually from an earlier date (with CO_2 capture used when needed). Furthermore, the observed model behavior does not seem far out of line when one considers that sequestered CO_2 represents 6 percent of the CCS scenario's electric sector total carbon emissions in 2015 (5 percent of the BAU scenario's), and increases to only 30 percent (21 percent of the BAU level) in 2030. Finally, as noted earlier, the model labels its integrated coal-fired, CO_2 capture technology "IGCC" as current thinking tends to assume that this combination would be cheaper than new pulverized coal with capture. Advanced PC plants with capture, however, could achieve costs and efficiencies similar to those used here to represent IGCC and would be nearly indistinguishable in MARKAL. The large per-period investment in what appears to be a single technology could actually be a mix of advanced coal-based designs. The following set of scenarios explore the growth rate issue in tandem with the other CO_2 trajectories. One must keep in mind, however, that results should always be interpreted as indicating what would be optimal from a least-cost perspective – a target, for instance, for allocating research, development, and deployment resources.

The initial CCS scenario added a total of 119 GW of new IGCC units with capture through 2030, starting with 25 GW in 2015. Restricting CCS growth to an initial 10 GW per technology (including retrofits) with a 10 percent annual growth rate limit reduces the cumulative CCS installation over the same timeframe to 106 GW, with 94 GW IGCC (a binding constraint) plus 12 GW NGCC; 40 GW of new conventional NGCC, entering between 1995 and 2030, makes up the difference. A 5 GW initial period limit with the same growth rate results in 89 GW, split nearly evenly between new IGCC and NGCC with capture. Both restrictions lead to a small investment in existing coal plant retrofits (< 10 GW). Note that a growth rate restriction similar to that employed in the nuclear analysis (i.e., a 3 or 4 GW first-period limit and initial annual growth rate of 25 percent) does not affect cumulative CCS installation. The remainder of the section (except where noted) uses a 10 GW per technology initial investment limit with a 10 percent annual growth rate. The more restrictive 5 GW initial limit may seem more realistic but, as argued above, induced technology change is difficult to predict and the looser limit reduces the chance that modeling assumptions will arbitrarily drive results.

Growth rate restrictions play a more important role with electric sector CO_2 trajectories that depart further from BAU assumptions. Figures 5.4 and 5.5 depict the least-cost mix of generating technologies that attain emission trajectories corresponding to 80 and 50 percent of 1995 level, respectively, starting in 2015. Both scenarios adopt a mix of IGCC (94 GW in each) and NGCC capture units (52 and 68 GW, respectively), with a minor retrofit investment. As before, the IGCC limits are binding. New NGCC units also play a larger role in each scenario, with nearly 500 GW of new (conventional) capacity installed in the most restrictive CO_2 trajectory between 1995 and 2030. Compared to the initial CCS scenario (which held CO_2 emissions at 1995 levels), SO_2 emissions decline significantly below BAU output (Figure 5.6) for both emission trajectories examined here. Electric sector NO_X emissions decline below their constrained values only for the lowest carbon trajectory.

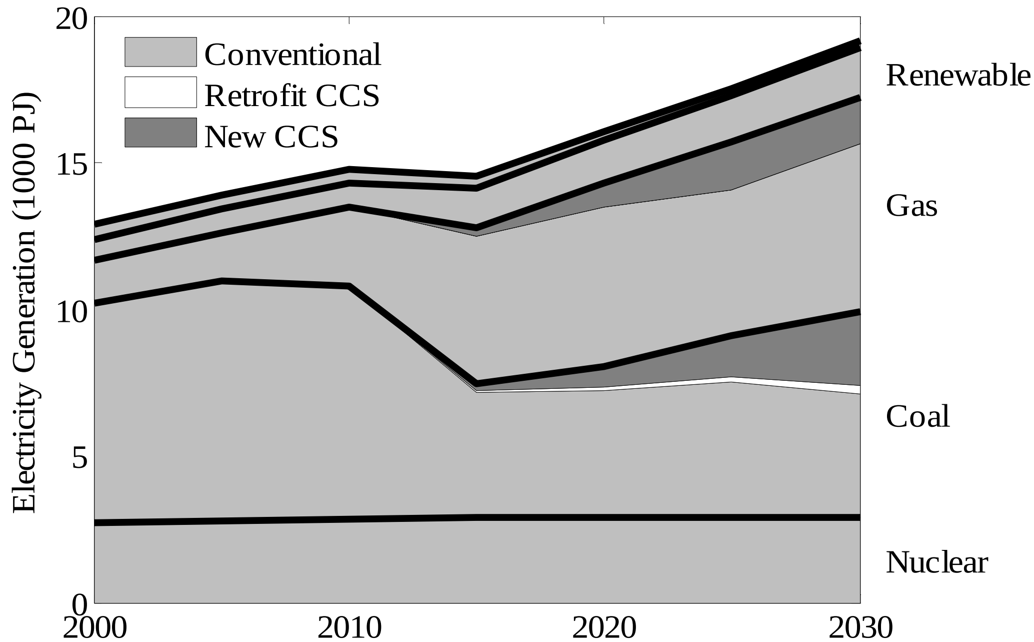


Figure 5.4: Electricity generation per-period by technology class for the 80 percent emissions scenario (electric sector CO_2 emissions held constant at 80 percent of 1995 levels from 2015 on, with CCS growth constraints in place).

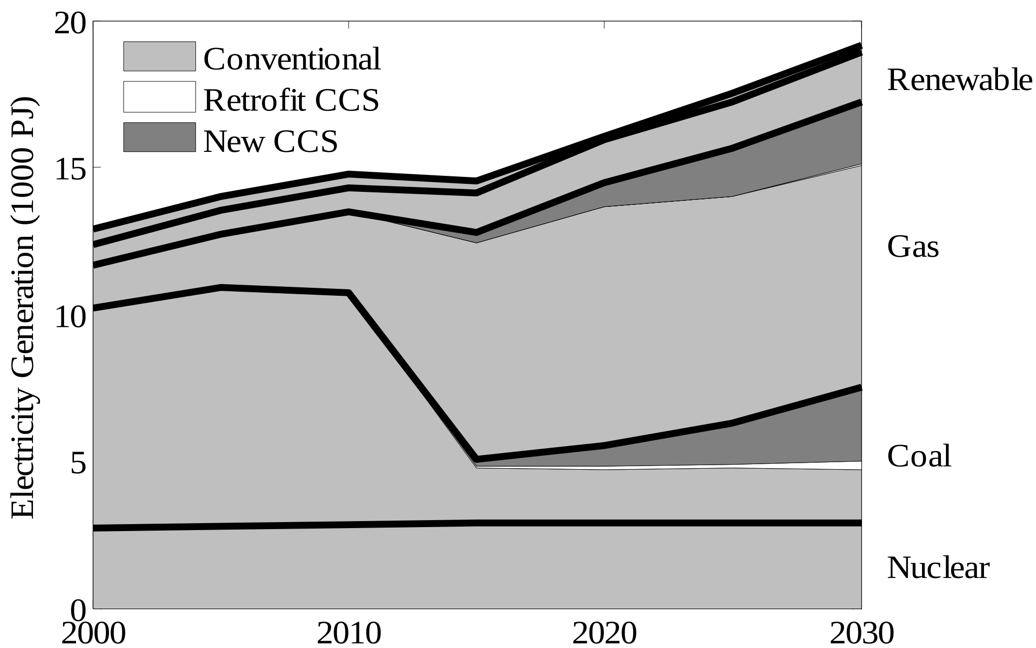
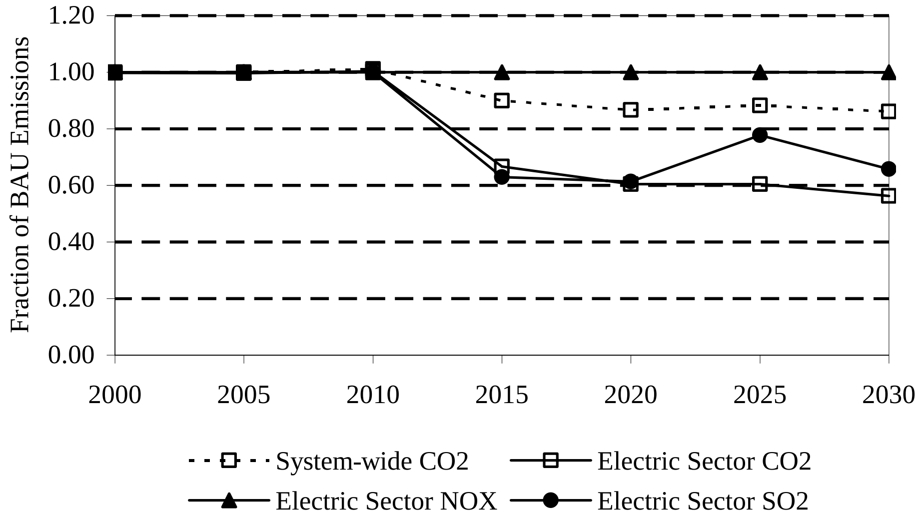
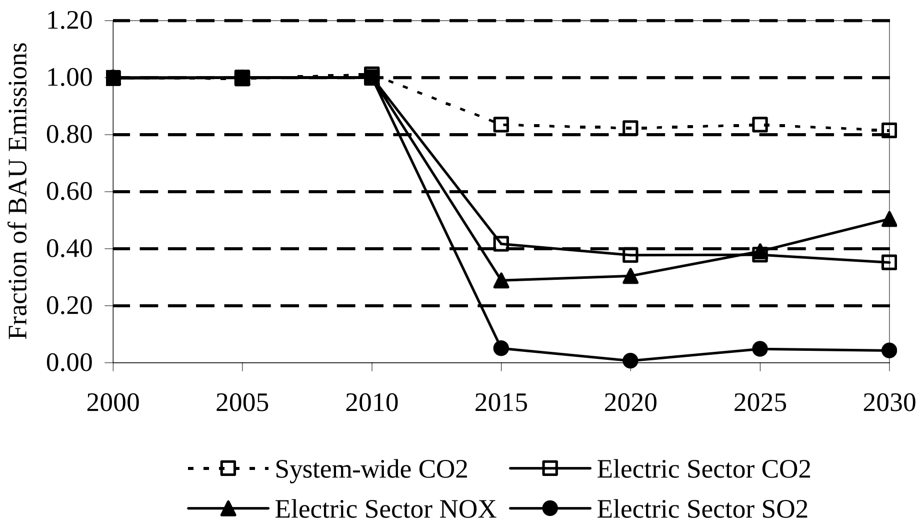


Figure 5.5: Electricity generation per-period by technology class for the 50 percent emissions scenario (electric sector CO_2 emissions held constant at 50 percent of 1995 levels from 2015 on, with CCS growth constraints in place).



(a)



(b)

Figure 5.6: Electric sector CO_2, SO_2, and NO_X and economy-wide CO_2 emissions as a function of time for (a) the 80 percent emissions scenario and (b) the 50 percent emissions scenario.

The relative consistency of these results across emission scenarios points to the need to examine how CCS technology specifications affect model behavior. Tables 5.5 and 5.6 show how different generating technologies compete to meet demand for two sets of parametric sensitivity analyses under the original CO_2 trajectory. To avoid conflating growth rate dynamics with the effects of interest, both sets of analyses exclude these constraints.

The first set of analyses (Table 5.5) varies the costs and input fuel requirements (the inverse of efficiency) of all CCS technologies (new and retrofit) by ± 20 percent from their base line values. Two trends stand out. First, when CCS technologies perform better and cost less than baseline assumptions, new integrated NGCC units with CO_2 capture enter to meet part of the shoulder generation (between base and peak load) previously supplied by conventional NGCC capacity. The overall share of gas technologies, however, remains constant (even though it is not constrained) and existing coal units increase their output to meet part of the baseload generation previously supplied by IGCC plants with capture. The efficiency improvement in this scenario reduces the NGCC capture unit operating (fuel) cost disadvantage relative to IGCC. Next, when efficiencies are low, but costs high, existing coal plant retrofits enter at the expense of IGCC capture units. These results correspond to intuition: retrofits are at both a cost and efficiency disadvantage to new integrated CCS units. When these shortcomings are removed, retrofits become somewhat competitive. The next set of sensitivity analyses explores this dynamic further. Note that the high CCS cost, high fuel requirement (low efficiency) scenario looks similar to the base CCS run; differences are due to rounding and the slightly reduced centralized electric power production in the former scenario.

Table 5.5: Share of electricity generation in 2030 by technology for the initial CCS scenario (CO_2 emissions held constant at 1995 level from 2015 on) and four parametric analyses of differences in CCS technology costs (investment plus all operating) and efficiencies (expressed here as change in input fuel requirements) relative to baseline values.

	Share of Electricity Generation in 2030				
Fuel Input	-20%	-20%	20%	20%	Base CCS Scenario
Cost	-20%	20%	-20%	20%	
Nuclear	0.15	0.15	0.15	0.15	0.15
Existing Coal	0.36	0.30	0.26	0.27	0.29
New PC	0.00	0.00	0.00	0.00	0.00
IGCC	0.00	0.00	0.00	0.00	0.00
Existing Coal Retrofit	0.00	0.09	0.00	0.00	0.00
New PC Retrofit	0.00	0.00	0.00	0.00	0.00
IGCC Retrofit	0.00	0.00	0.00	0.00	0.00
IGCC+CCS	0.10	0.06	0.20	0.18	0.17
Gas	0.14	0.30	0.30	0.30	0.30
NGCC Retrofit	0.00	0.00	0.00	0.00	0.00
NGCC+CCS	0.15	0.00	0.00	0.00	0.00
Renewables	0.09	0.09	0.09	0.09	0.09
Other	0.01	0.01	0.01	0.01	0.01

The second set of parametric sensitivity analyses attempts to tease out the main drivers of CCS retrofit behavior (Table 5.6). Once again, two trends are noticeable. First, energy penalty improvements (decreases in input fuel requirements) help retrofits of existing pulverized coal plants and new IGCC capacity without CCS become economically competitive with integrated IGCC capture units. As efficiency improves further, coal plant retrofits loose market share to NGCC capture conversions. This is the same pattern seen above: the efficiency improvement reduces the operating cost disadvantage gas plants experience as a result of their higher fuel costs. New, integrated NGCC capture units are not affected by this sensitivity analysis and do not enter the mix of generating plants. Equivalent improvements in retrofit costs do not have as large an impact. As investment and operating costs decline, retrofits of existing coal plant increase, reducing the share of power new IGCC capture units generate. Simultaneous improvement in both retrofit costs and efficiencies combines these effects. Note that new pulverized coal plant retrofits never become a competitive investment option.

Table 5.6: Share of electricity generation in 2030 by technology for the initial CCS scenario (CO_2 emissions held constant at 1995 BAU levels from 2015 on) and four parametric analyses of differences in CCS retrofit technology costs (investment plus all operating) and efficiencies (expressed here as change in input fuel requirements) relative to baseline values.

	Share of Electricity Generation in 2030					
Fuel Input	-20%	-40%	100%	100%	-20%	Base CCS Scenario
Cost	100%	100%	-20%	-40%	-20%	
Nuclear	0.15	0.15	0.15	0.15	0.15	0.15
Existing Coal	0.30	0.37	0.28	0.28	0.34	0.29
New PC	0.00	0.00	0.00	0.00	0.00	0.00
IGCC	0.00	0.02	0.00	0.00	0.00	0.00
Existing Coal Retrofit	0.09	0.04	0.03	0.06	0.06	0.00
New PC Retrofit	0.00	0.00	0.00	0.00	0.00	0.00
IGCC Retrofit	0.06	0.02	0.00	0.00	0.05	0.00
IGCC+CCS	0.00	0.00	0.14	0.12	0.00	0.17
Gas	0.30	0.12	0.30	0.30	0.20	0.30
NGCC Retrofit	0.00	0.18	0.00	0.00	0.10	0.00
NGCC+CCS	0.00	0.00	0.00	0.00	0.00	0.00
Renewables	0.09	0.09	0.09	0.09	0.09	0.09
Other	0.01	0.01	0.01	0.01	0.01	0.01

These CCS sensitivity analyses showed that gas units with CO_2 capture could be competitive with their coal-fired counterparts when efficiency improvements reduced the impact of the price difference between natural gas and coal. More generally, fuel switching from coal to gas provides an alternative to CCS. Hence, the impact of natural gas prices on technology penetration is worth exploring via its own sensitivity analysis. Figure 5.7 compares the share of generation in 2030 from conventional gas versus CCS units for the baseline CCS scenario plus additional scenarios incorporating a 10 $/GJ markup in economy-wide natural gas prices as well as a 3 $/GJ cut. The markup decreases the share of gas generation by 3%, and leaves CCS unchanged. The gas price cut affects neither. These results are partly an artifact of the MARKAL model, which treats NGCC as non-baseload capacity and therefore prevents NGCC capture units (new and retrofit) from substituting for their coal-fired counterparts. Gas price markups smaller than 10 \$/GJ had no effect on results. Note that these scenarios do not include the CCS growth constraints; equivalent runs with the constraints in place prevented investment in additional coal-fired CCS capacity (the preferred option) and only increased the overall share of gas 4 percent by adding new NGCC plants with capture when gas prices were low (conventional NGCC did not change).

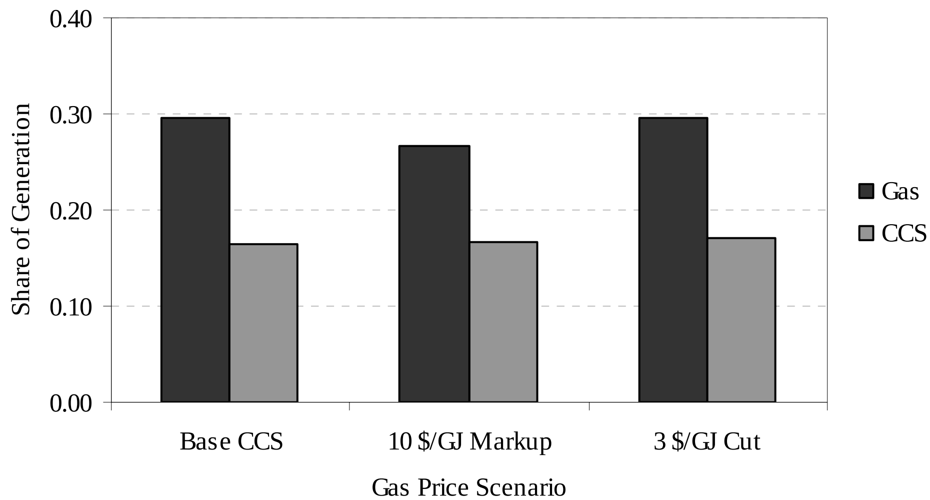


Figure 5.7: Share of electricity generation for conventional gas and all CCS technologies under three gas-price scenarios.

Finally, the analysis in this section has focused on the technological side of CO_2 capture. Sequestration enters the analysis as a single 28 dollar cost per ton of carbon (approximately 7.5 \$/tCO_2) transported and injected, based on a moderate plant-to-well distance and a high-end estimate for both costs derived from the IPCC synthesis report (2005). Actual sequestration costs will be site specific. Moreover, as noted, an average cost figure fails to capture important drivers such as uncertainty over public acceptance, the regulatory environment, and the need for long-term monitoring. Where CO_2 has economic value, such as for enhanced oil recovery, the gas could be sold for profit. Such opportunities could provide a niche market for capture technologies, fostering learning-by-doing and lowering its costs. These issues require a more detail analytical strategy and modeling environment than employed here. As a check on sensitivity to model assumptions, however, two additional scenarios explored the impact of halving and doubling sequestration costs – the likely range of variation for power plants operating in the U.S. Neither change had an appreciable effect on results for the baseline CCS scenario, supporting the view that capture would dominate CCS from an economic perspective (IEA, 2004; IPCC, 2005).

5.4 Conclusions

This section has taken an initial look at how carbon capture and sequestration technologies function in the U.S. EPA National MARKAL energy systems model. The energy systems context is important as CCS would compete with measures to reduce the carbon intensity of power production and efforts to improve end-use efficiency. Driven by an assumed electric sector CO_2 trajectory, the model adopts CCS mainly for baseload generation in the form of new IGCC capture capacity. The analysis does not consider demand-side measures, but the model is seen to rely on coal-to-gas fuel-switching as much as it does on CCS under the assumed carbon trajectories. The next section examines CCS relative to nuclear power and renewable energy sources, two other prominent means of reducing the carbon intensity of power production. Like the previous section's nuclear power analysis, moderate levels of CCS adoption do not significantly affect electric sector criteria pollutant emissions. CCS displaces new baseload capacity under these circumstances, but does not significantly impact the operation of existing coal-fired plants, which contribute most of the sector's Clean Air Act constrained SO_2 and NO_X.

Several limitations of this section's analysis should be kept in mind. First, MARKAL is not a dispatch model. Consideration of how different generation technologies operate over the course of a typical day would help tease out how technology use affects investment patterns, as discussed earlier (Johnson and Keith, 2004). Technology adoption—particularly the competition between CCS and coal-to-gas fuel switching—would also look different in a model that treated NGCC units as baseload capacity (a competitor to IGCC capture units). Likewise, the analysis would benefit from a more detailed representation of existing coal-fired power plants; the retrofit option, for instance, might look better with greater model resolution. Next, the model assumes static cost and efficiency values for all CCS technologies. Since, learning and economy-of-scale improvements in both sets of CCS parameters would likely occur, this assessment of CCS is probably conservative (though the course of technology development is difficult to predict and all electric sector technologies would be subject to leaning). Finally, CCS is not restricted to the electric sector. IGCC capture plants, for instance, could produce electricity as needed during the day, and use excess capacity during non-peak hours to produce H_2 for use as a transportation fuel. Other industrial applications of CCS are possible (see, e.g., IPCC, 2005). Future work will explore these issues to see their full effect on air quality.

Section 6

Nuclear Power, Carbon Capture and Sequestration, and Wind Generation: The Competition Among Technology Alternatives

The previous sections built on the business as usual (BAU) analysis to examine how nuclear power or CO_2 capture and sequestration (CCS) technologies might contribute to meeting demand in U.S. electric markets and, in turn, impact air quality. Separate assessments enabled a higher-resolution look at the factors that affect the adoption of these alternatives to conventional power generation and the choice among the specific technologies that make up each class. This section explores how nuclear and CCS compete in the EPA National MARKAL Model (EPANMD). The analysis also loosens the constraints on wind generation to examine how these technologies fare against a prominent renewable energy option. Once again, the focus is on technology investment and how the resulting patterns of activity affect electric sector criteria pollutant emissions.

Like the preceding sections, this analysis relies on the arbitrary non-BAU carbon trajectories as a modeling device to stimulate investment in nuclear and CCS. Figure 6.1, for instance, shows how CCS fares against conventional nuclear power (light water and mixed-oxide reactors), natural gas, and wind when electric sector CO_2 emissions level off at its 1995 level in 2015. All technologies incorporate the baseline costs, efficiencies, and growth constraints assumed in the previous sections. Nuclear power increases its contribution to baseload generation, with 126 GW of new investment through 2030 (bumping up against its growth constraint), while a more modest 26 GW of new IGCC capture capacity comes on-line. Electric sector SO_2 and NO_X emissions remain constant at the bounds representing CAA rules. Offering advanced nuclear technologies (gas turbine modular helium and pebble bed modular reactors) as investment options increases nuclear power output slightly (from 33 to 34 percent of 2030 generation) at the expense of CCS (which decreases from 4 to 2 percent); the addition does not affect gas output (27 percent), wind (less than 10 percent), or criteria pollutant emissions.

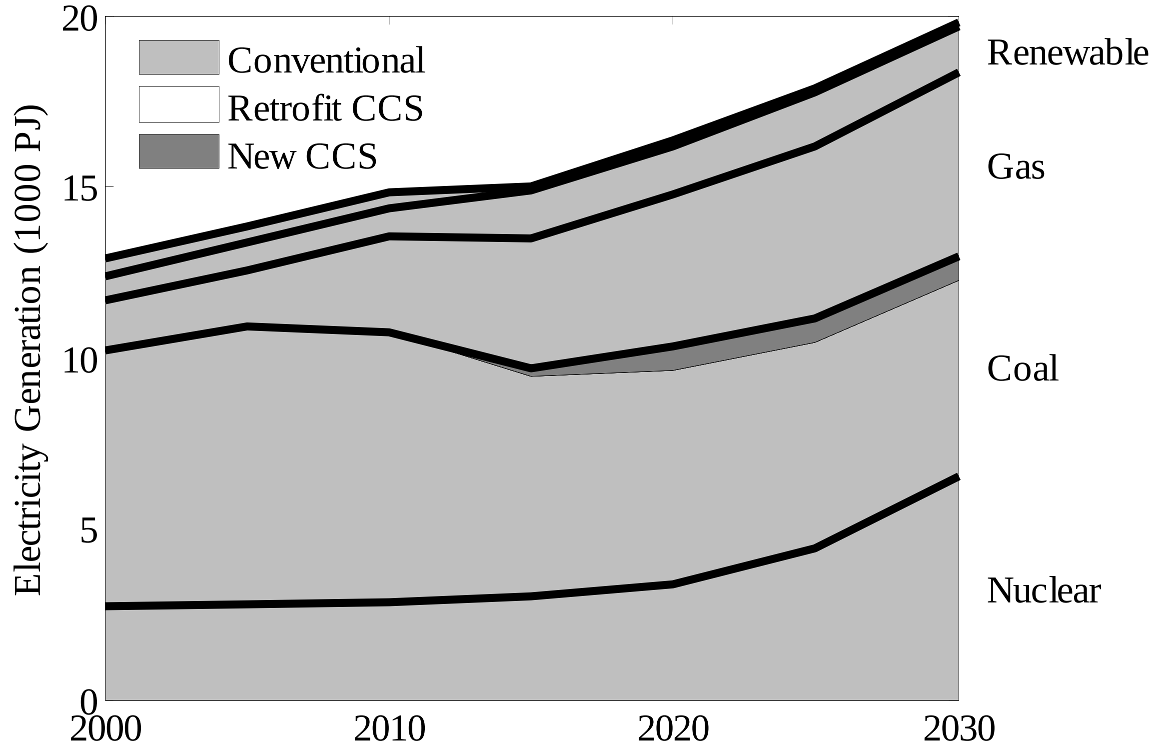


Figure 6.1: Electricity generation per period by technology class for the baseline CCS scenario (electric sector CO_2 emissions held constant at 1995 levels from 2015 on, with no CCS growth constraints). Note that nuclear includes only conventional (LWR and MOX reactors) technology.

A further departure from the electric sector CO_2 trajectory alters this picture slightly. Figure 6.2, for instance, illustrates how different technologies contribute to meeting electricity demand for a CO_2 trajectory that holds steady at 50 percent of 1995 emissions from 2015 on. When nuclear investment is limited to conventional technologies, nuclear power once again hits its growth constraint. CCS investment, however, increases, with integrated IGCC CO_2 capture units generating 7 percent of 2030's electrical output and NGCC with capture producing an additional 4 percent. The model also adds CCS retrofits to a modest part of the existing coal plant capacity. Criteria pollutant emissions under this scenario decrease well below their upper bounds, as generation in 2030 from the model's (nonretrofit) existing coal capacity drops from near 28 percent in the previous two scenarios to slightly more than 3 percent. SO_2 emissions are reduced by about 90% below CAA restrictions, and NO_x emissions are reduced by half (Figure 6.3).

Expanding investment options to include advanced nuclear technologies increases nuclear generation from 34 to 42 percent of total 2030 output, while the contribution from both IGCC and NGCC capture units drops by half. Conventional gas-fueled technologies in both scenarios hovers around 30 percent.

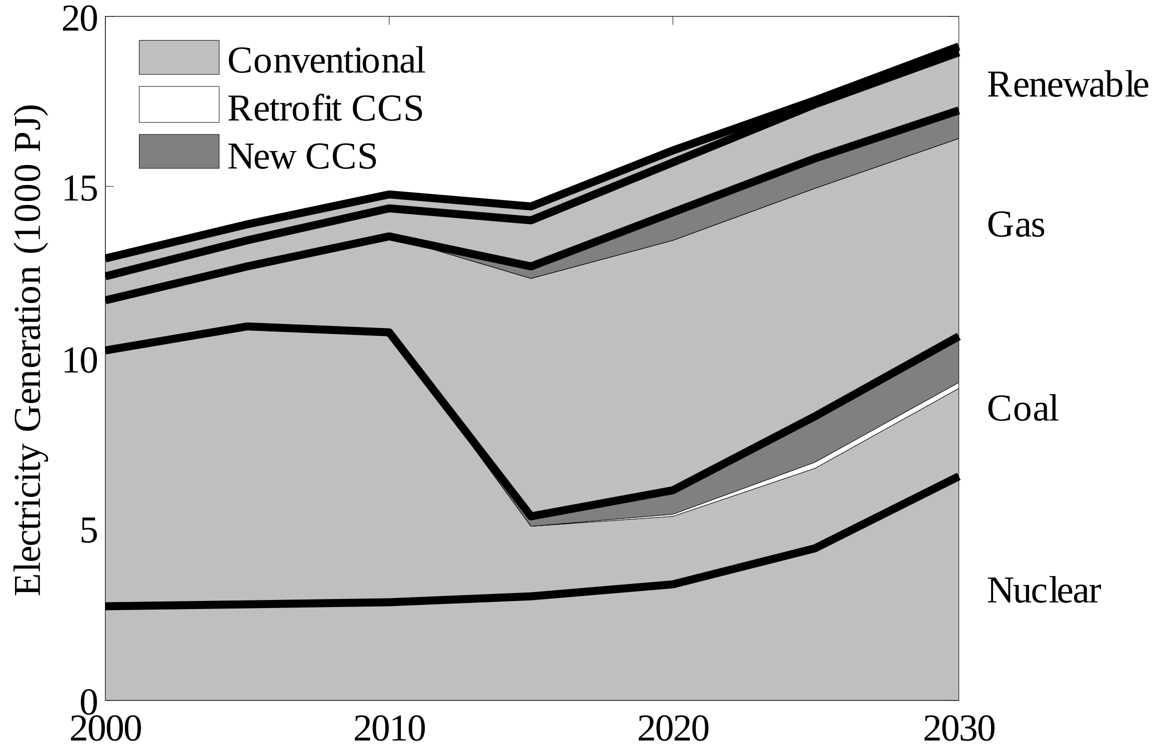


Figure 6.2: Electricity generation per-period by technology class for the 50 percent emissions scenario (electric sector CO_2 emissions held constant at 50 percent of 1995 levels from 2015 on).

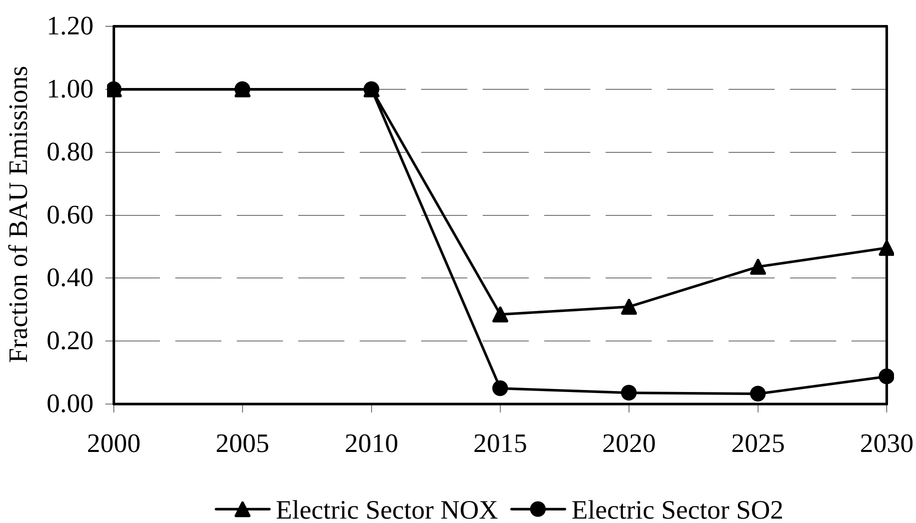


Figure 6.3: Electric sector SO_2, and NO_X emissions as a function of time for the 50 percent emissions scenario (electric sector CO_2 emissions held constant at 50 percent of 1995 levels from 2015 on).

These results show that both nuclear and gas-fired generation dominate CCS, given baseline technology assumptions. Figure 6.4 illustrates how generation by these technologies changes as a function of assumptions about CCS costs and efficiencies, nuclear capital costs, and electric sector natural gas prices. (Except where noted, electric sector CO_2 emissions level out at 1995 level in 2015, and only conventional nuclear technologies are available.) Note that the BAU wind constraints remain in place (and are preventing additional investment in wind turbines); this assumption will be relaxed in the following set of scenarios.

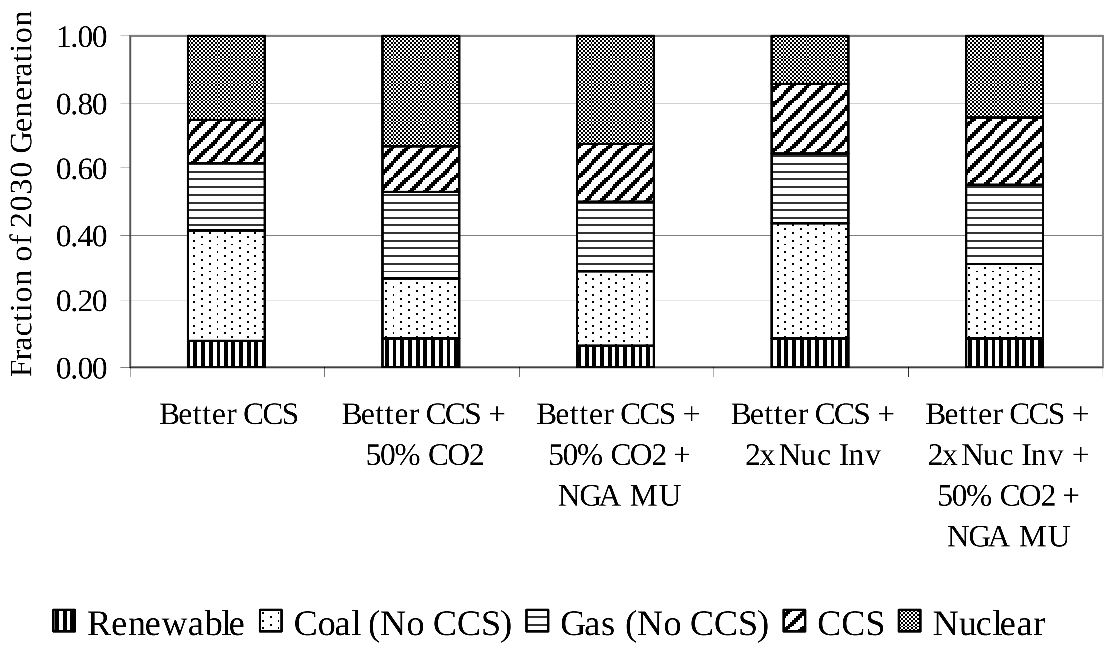


Figure 6.4: Fraction of 2030 electric power generation by technology class for five scenarios.

The Figure 6.4 scenarios attempt to improve the competitiveness of CCS relative to conventional nuclear power. The first scenario ("Better CCS") lowers all CCS costs and input fuel requirements (the inverse of efficiency) by 20 percent. Nuclear power's share of 2030 generation falls from 33 to 26 percent, while that of CCS increases from 4 to 11 percent – a mix of IGCC and NGCC units with CO_2 capture. CCS growth constraints bind for only two periods (2015 and 2020). Since the output from existing coal plants does not change, criteria pollutants remain at their BAU levels (i.e., the limits of their regulatory constraints).

The second scenario ("Better CCS + 50% CO2") examines the same CCS technology improvements under the 50 percent CO_2 trajectory. CCS maintains its higher share of output, but nuclear returns to its previous (limited) 33 percent share at the expense of existing coal-fired generation. The model also adds non-capture IGCC capacity, which contributes 12 percent of 2030 generation. The result is a significant decrease in electric sector SO_2 and NO_X emissions, which decline to 18 and 34 percent, respectively, of their 2030 BAU values. As this scenario also sees an increase of (non-CCS) gas-fueled generation from 21 to 26 percent, it is worth looking at the effects of a gas price increase. The third scenario ("Better CCS + 50% CO2 +

NGA MU") adds 10 $/GJ to electric sector gas prices. The price increase lowers the output of the model's gas capacity to its previous value; IGCC and NGCC units with CO_2 capture make up the difference (nuclear power continues to hit its growth constraint). Existing coal plants reduce their output further and non-capture IGCC increases its output to 19 percent, yielding an 88 percent reduction in 2030 SO_2 emissions and a 48 percent drop in NO_X from the electric sector.

The remaining two scenarios in Figure 6.4 attempt to advantage CCS further by increasing nuclear investment costs. Nuclear construction costs have been notoriously difficult to predict, and total project costs of nearly twice that of early estimates, for instance, mark the historical record (EIA, 1986). The fourth scenario ("Better CCS + 2x Nuc Inv") is equivalent to the first, with all (conventional) nuclear investment costs doubled. The results are similar, except that nuclear power's share of 2030 generation drops to 15 percent, while that of CCS increased to nearly 20 (with growth constraints binding through 2025); since existing coal capacity does not change, criteria pollutant emissions remain at BAU levels. The last scenario ("Better CCS + 2x Nuc Inv + 50% CO2 + NGA MU") adds the natural gas price markup and looks at technology penetration assuming the lower electric sector CO_2 trajectory. CCS maintains its higher output, but nuclear generation increases to 24 percent; non-capture IGCC provides 17 percent of 2030 output and existing coal units once again drop below 5 percent. These dynamics result in the lowest electric SO_2 emissions of any scenario (8 percent of BAU levels) and a NO_X reduction to approximately two-thirds of the modeled CAA limits.

Finally, these scenarios pitting nuclear and CCS are somewhat unrealistic in that they maintain tight growth constraints on renewables. Wind generation is becoming economically competitive with gas as natural gas prices remain at historically high levels and wind turbine technology continues to improve. Wind therefore deserves consideration in this analysis. While nuclear and CCS can be dispatched to supply baseload electricity, wind is an intermittent source of power that tends to displace load-following units such as gas turbines. The EPANMD also lacks the regional specificity needed to capture important differences in the availability of wind resources (i.e., regional wind classes, which characterize typical wind speeds). In the EPANMD, wind is simply available anywhere, subject to the assumed growth and availability constraints. A more accurate representation would include a resource supply curve to reflect the increasing cost of deploying wind turbines in less-suitable regions of the country. The same argument, of course, holds for solar and other renewable technologies.

These caveats should be kept in mind while considering the final set of scenarios, which look at the competition between wind generation, nuclear power, and CCS under the relaxed wind growth constraints (these are equivalent to the Section 4 nuclear growth constraints). Figure 6.5 summarizes 2030 generation by technology class; all scenarios adopt the 50 percent of BAU CO_2 trajectory to stimulate alternative technology penetration.

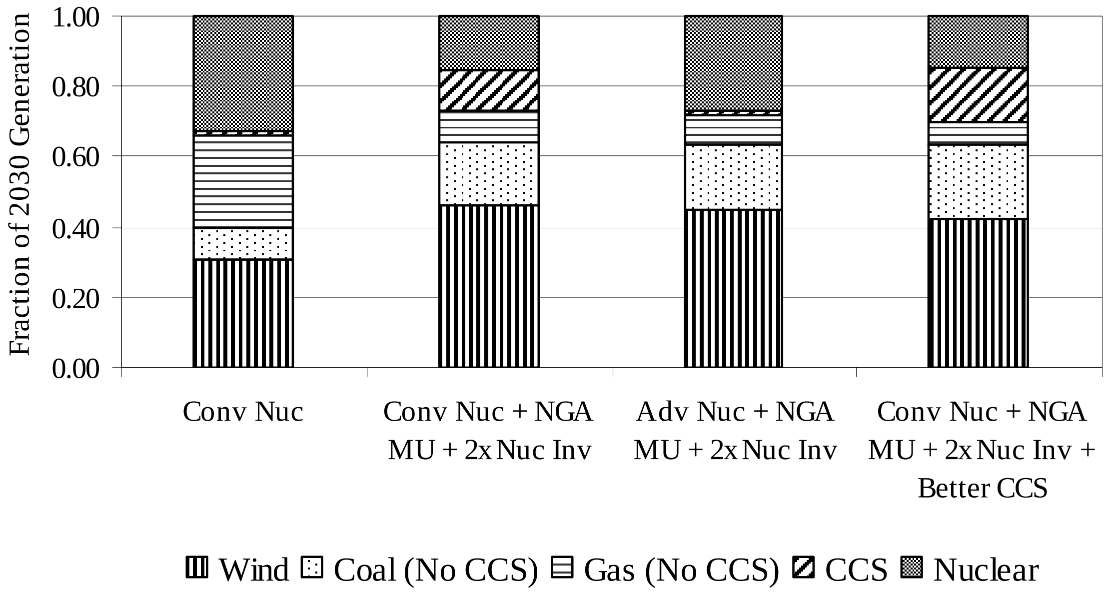


Figure 6.5: Fraction of 2030 electric power generation by technology class for four scenarios with the relaxed wind growth constraints.

The first relaxed wind scenario ("Conv Nuc") restricts nuclear investment to conventional technologies. Wind and nuclear each contribute around 30 percent of 2030 generation, with gas responsible for an additional 25 percent and existing coal units making up the difference (Figure 6.6). Electric sector SO_2 emissions fall to 10 percent of their constrained values, while NO_X declines to 75 percent (the increase in gas-fired generation largely explains this pattern). CCS plays a trivial role. An increase in gas prices coupled with higher nuclear investment costs ("Conv Nuc + NGA MU + 2x Nuc Inv") increases wind's share of generation to 45 percent, decreases nuclear output to 15 percent, and results in the growth of CCS to 12 percent by 2030. Existing coal plants (18 percent) and gas (10 percent) contribute the rest. NO_X emissions remain at their constrained limits, while SO_2 falls to 40 percent of its upper bound. Opening nuclear investment to advanced technologies, while maintaining the gas and nuclear investment cost mark-ups, increases nuclear output to over 25 percent ("Adv Nuc + NGA MU + 2x Nuc Inv"). CCS once again plays a trivial role in meeting electric power demand. Electric sector criteria pollutants remain essentially unchanged. Finally, improvements in CCS costs and efficiencies ("Conv Nuc + NGA MU + 2x Nuc Inv + Better CCS") lower gas-fueled generation somewhat when only conventional nuclear investment is allowed, at the expense of higher electric sector SO_2 emissions (approximately two-thirds of their constrained value).

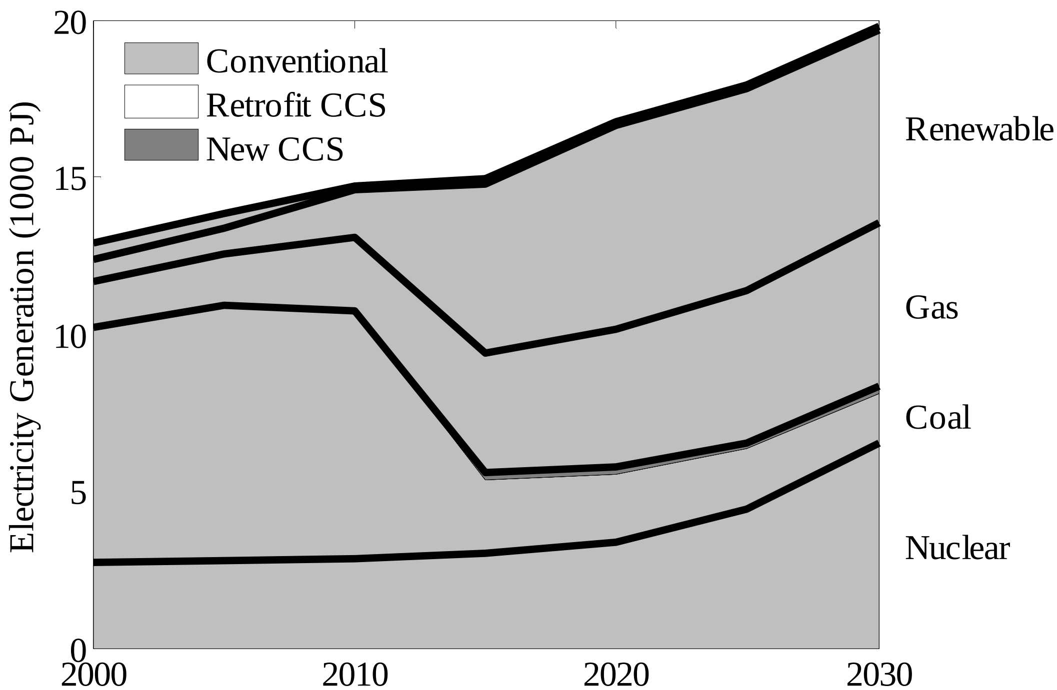


Figure 6.6: Electricity generation per-period by technology class for the 50 percent emissions scenario (electric sector CO_2 emissions held constant at 50 percent of 1995 levels from 2015 on) under the relaxed wind growth constraints with nuclear investment restricted to conventional technologies (the "Conv Nuc" scenario in Figure 6.5).

These results provide an indication of how nuclear power, wind generation, and CCS might fare against each other. The last set of scenarios, as noted, is tentative pending improvements in the U.S. EPA's National MARKAL modeling framework. The results, however, suggest that wind and nuclear together could displace a significant portion (60 percent) of fossil-fuel electric generation, though the co-control emissions benefits of this substitution may not be that substantial and depend largely on how existing coal plants are used. An important caveat is whether and how system operators of electricity grids could manage the intermittent output of wind serving such a large fraction of demand. Future work on the EPANMD includes a representation of backup generation to complement intermittent resources.

In conclusion, several key results emerge from this section's integrated technology assessment:

- The penetration of advanced technologies does not necessarily yield a significant criteria pollutant benefit. Under all but the most radical departures from BAU electric sector carbon trajectories, for instance, nuclear power and CCS merely replace the new coal and gas capacity that are needed to meet increasing electricity demand. The model maintains its existing coal plants through their useful lifetime, and criteria pollutant emissions remain near their Clean Air Act limits as a result. These existing plants, which are free of amortized investment costs, remain too economical to retire as baseload capacity—an observed trend noted in the literature (e.g., Ellerman, 1996). This picture changes when electric sector carbon emissions depart furthest from their BAU levels and CO_2 emissions from baseload plants declines. Even in these cases, however, the decrease in NO_X emissions is more modest than that seen in SO_2.

- CCS is dominated by investment in new nuclear technologies as well as additional gas-fired generation and wind power. Only when favorable CCS cost and efficiency assumption combine with high nuclear investment cost and gas price scenarios does CCS approach its modeled growth constraints over the full time horizon in which it is available (2015-2030). Furthermore, given that CO_2 capture and geologic sequestration are both untested at even the modest scales adopted here, these results are probably optimistic.
- Even with a rudimentary conception of wind resources, wind generation in the EPANMD competes for a significant share of electric power output when the model incorporates more favorable growth constraint assumptions for new turbine investment. These growth limits are modest compared to some predictions, though a more realistic representation of unit dispatch is needed to capture the technology's intermittency (beyond lowering the annual availability of wind turbines, as is done here) and evaluate its actual potential.

Section 7

Limitations, Future Model Development, and Analysis Directions

While the model results provide insight into future energy technology pathways, they are nonetheless based on a model, and all models have limitations that introduce caveats. This section identifies and discusses some of the limitations associated with the EPANMD and MARKAL model. Planned strategies and future work to address these limitations are interwoven in the discussion. The report concludes with next steps towards fulfillment of ISA-W's role in EPA's Air Quality Assessment.

The use of national rather than regional inputs to MARKAL is perhaps the most significant limitation affecting the analysis. The EPANMD is a national database that does not contain region-specific data. The lack of regional data manifests itself in three key limitations. First, important regional differences in resource supplies, energy service demands, and technology availability cannot be represented. An example of where this limitation would affect model results is in an evaluation of renewables, such as biomass and wind. In the EPANMD, renewable resources are represented by aggregated national supply curves, if at all. For example, biomass resources are represented by a single 7-step supply curve that aggregates biomass resources across the nation. Wind does not have a supply curve, but rather an assumed capacity factor (which implies the strength of the wind resource) of 35 percent. These representations do not account for widely varying resource quantities and costs from one region to another. To address regional differences explicitly, ISA-W is developing a nine-region MARKAL database (EPA9R) that will account for variations in supply, demand, and technologies between the nine U.S. Census regions. We expect to use the EPA9R database to examine renewables in the future.

Second, the EPANMD does not include transportation costs for coal or other resources. As with renewables, transportation costs will affect regional technology penetration, and by extrapolation, the aggregate technology penetration at the national level. In particular, the inclusion of transportation costs will have the greatest effect on energy resources with low energy density, such as biomass or low grade coals. It is not cost-effective to ship these resources on transnational scales, but such transport may be occurring implicitly within EPANMD modeling. Transportation costs for energy resources will be included in EPA9R.

Third, air pollution regulations that have been implemented on a state or regional level must be modeled at a national level within EPANMD. Air pollution is a problem that has multiple scales. Damages from air pollution occur at the local scale, affecting human health, agriculture, and ecosystems. Some of the pollutant emissions contributing to air pollution are from local sources, but others typically are emitted from upwind sources both within and outside the state. In this context, federal air quality regulations, including the Clean Air Act (CAA) and the Clean Air Interstate Rule (CAIR), contain provisions that reduce emissions at the local and regional scales. For example, the CAA introduces national ambient air quality standards that must be met at the local level. States must develop plans for reducing emissions to these standards, so these plans typically result in local- or state-level emissions reductions. To address regional- and national-scale transport of emissions, the CAA also place NO_X and SO_2 emissions limits on individual boilers. Utilities are given the option of trading emissions credits so that the emissions reductions occur in aggregate, but, through purchasing emissions credits, individual boilers may exceed the limit. CAIR was also developed to reduce the transport of pollutants from one state to another. In CAIR, states within the eastern U.S. are assigned budgets that account for the effects of their emissions on downwind states within the region. States have considerable freedom in determining how to comply with their budgets.

The regional- and state-level complexities of these regulations complicate modeling emissions regulations within EPANMD. Resulting projections for the use of emissions controls can be quite different from what is seen "on the ground." As a result of CAIR, for example, most coal-fired boilers east of the Mississippi are expected to use SCR controls for NO_X. By not representing the regional requirements of CAIR, however, EPANMD favors SNCR, which has lower costs but also lower NO_X removal efficiencies. A state or regional representation of control requirements would produce results that are closer to what will actually be implemented. With the development of EPA9R, ISA-W expects to be better able to represent regional-level implementation of national rules. State-level differences will still be difficult to capture within EPA9R.

Other limitations are unrelated to the lack of regional specificity in the EPANMD. First, MARKAL is not an electric dispatch model: the user is limited to exactly six time slices in which to specify all demands (see Shay, et al. 2006). The time slices represent two diurnal time periods (day and night) as well as three seasons (summer, winter, and intermediate); the 6 time slices come from the combination of times of day and seasons enumerated above. The specification of demands according to these time slices results in a flat demand profile compared with the more conventional load duration curve used to specify demand in electric dispatch models. The result is that MARKAL tends to favor baseload units with high capital costs and low marginal costs (e.g., coal and nuclear) over units with higher marginal costs that are better suited to meeting peak and shoulder demand (e.g., gas turbines and wind). ISA-W is addressing this MARKAL limitation by funding the development of flexible time slices, so the user can specify as many time slices as desired to more accurately represent the profile of electricity load. The expanded time slices will be included in the EPA9R model.

The EPANMD's simple representation of the nation's existing coal-fired generating infrastructure is an additional limitation. The database contains just three types of pre-existing coal plants: bituminous, sub-bituminous, and lignite steam. In reality, a diverse variety of coal plants exist, with performance and emissions that are highly dependent on their vintage and detailed characteristics of the coal used to supply the plants. Future development will include an expanded representation these existing technologies.

Finally, the analysis excludes consideration of efficiency improvements as well as non-traditional generating technologies, like combined heat and power, which could supply a large share of the nation's electricity in the coming decades. End-use efficiency improvements, in particular, are promising as they could significantly reduce electricity demand by 2030 (Laitner, et al. 2005). Ignoring the potential for a significant demand reduction, as this analysis does, biases conclusions in favor of advanced generating technologies like nuclear power and CCS under certain scenarios. The non-BAU carbon trajectories, for instance, through their impact on the cost of electricity, would likely spur as much investment in end-use energy efficiency measures as they do in alternative supply-side technologies. Likewise, the analysis does not consider the impact of radical technological innovation, such as the emergence of “nano-bio-info” technologies, on future energy demand (see Laitner, 2006, for an overview). Surprises in principle are difficult to anticipate, and this assessment makes no attempt to cover all scenarios that may play out in the future.

Future Work

With the transportation and electricity sector assessments complete, work will involve using the EPANMD within a variety of applications. One such application is the development of future-year emissions scenarios for the EPA Office of Research and Development’s Global Change Air Quality Assessment. These scenarios will be used to project criteria pollutant emissions out to the year 2050. The emissions will then be used within an air quality model to characterize the impacts of increased energy service demands and technological change on regional air quality.

ISA-W also plans to use the EPANMD to assess the prospects and implications of particular technologies. Using formal sensitivity analysis techniques, MARKAL can be used to identify the conditions in which a particular technology is competitive, the sectoral and cross-sector fuel implications of the penetration of the technology, and the resulting emissions. An example of such an analysis is the recently completed evaluation of hydrogen fuel cell vehicles (Yeh et al. 2006). Additional technologies that we expect to assess with the EPANMD include advanced nuclear power, coal gasification, and plug-in gasoline-electric hybrids.

Another potential application for the EPANMD is in the area of risk assessment and risk management. Within a probabilistic framework, MARKAL can be used to identify the conditions that lead to poor air quality or depletion of specific fuel resources. The model can then be used to identify technological pathways to minimize these risks.

Through these and other applications, we expect EPANMD, and later, EPA9R, to play an important role in EPA’s efforts to understand the linkage between energy and emissions and use this understanding to protect the environment and human health into the future.

Section 8
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