Retrofitting Coal-Fired Power Plants for Carbon Dioxide Capture and Sequestration - Exploratory Testing of NEMS for Integrated Assessments

DOE/NETL-2008/1309

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Acknowledgements

The assistance of several individuals was especially helpful in completing this study and report. Jeffrey Jones, EIA, provided expertise and assistance with the necessary coding modifications to the Electricity Marketing Module in NEMS. Overall guidance and encouragement were provided by Phil DiPietro, OSAP Benefits Team Leader. Technical writing services were provided by Gregory A. Washington, RDS.

Summary

As part of an assessment for analyzing the prospects of retrofitting existing coal-fired power plants for carbon dioxide (CO_2) capture and sequestration, an integrated analysis using the National Energy Modeling System (NEMS) of the Energy Information Administration was undertaken using a generic model of retrofit costs as a function of basic plant characteristics (such as heat rate). Modifications to NEMS were made to enable an endogenous determination of the tradeoffs between retrofit, retirement, and the purchase of emission allowances.

The cost for CO_2 retrofit included direct costs (capital and O&M), indirect costs (capacity and heat rate penalties), and a nominal cost for transportation, injection, measurement, monitoring, and verification (MMV).

The penetration of retrofits across the fleet was not observed at any significant extent until carbon emission allowance prices exceeded \$30/MTCO$_2$e (metric ton CO_2 equivalent). Retrofits did not occur through 2030 at 30 \$/MTCO$_2$e, but about one third of the starting coal fleet capacity was retrofitted at 45 \$/MTCO$_2$e and about one half at 60 \$/MTCO$_2$e. The impact of retrofitting on coal plant retirements, builds of replacement capacity, and carbon emissions depended upon the carbon emission allowance price. Retrofitting resulted in the avoidance of 128 GW of coal plant retirements through 2030 at 45 \$/MTCO$_2$e, and 149 GW at 60 \$/MTCO$_2$e. This was offset by capacity deratings of 30 percent for the retrofitted plants, or 30 GW and 50 GW at 45 \$/MTCO$_2$e and 60 \$/MTCO$_2$e, respectively. Combined, capacity deratings and plant retirements decreased by 98 GW at 40 \$/MTCO$_2$e and decreased by 99 GW at 60 \$/MTCO$_2$e.

The impact of higher electric utility gas prices on retrofitting was also tested at various carbon emission allowance prices. At 45 \$/MTCO$_2$e, gas prices about 5 \$/MCF higher than in the baseline (resulting in prices comparable to those in the Annual Energy Outlook (AEO) 2007[1] high world oil price scenario), increased retrofits through 2030 by almost 25 GW, inducing retirements to fall by almost 20 GW. At 15 - 30 \$/MTCO$_2$e, no retrofits were observed at any gas price.

The penetration of retrofits observed in this exploratory work represents a possible upper boundary for their potential, because the generic model for retrofit costs discriminates largely on plant heat rate. Site-specific factors that were not considered in this analysis are likely to be major factors for certain plants. On the other hand, the generic model was not predicated on advanced technological concepts for CO_2 capture and retrofit.

Introduction

This paper presents an exploratory NEMS-based analysis of retrofitting existing coal-fired power plants for CO_2 capture and sequestration. A generic cost representation is assumed valid across the fleet, without consideration of site specific factors. A recent NETL study of an advanced amine process retrofitted into Unit 5 of American Electric Power's (AEP) Conesville, Ohio plant

[1] Energy Information Administration, "Annual Energy Outlook 2007," DOE/EIA-0383(2007), February 2007.

undertaken by NETL in conjunction with Alstom Power was used as a basis for the cost data for capture[2]. This plant was selected because it serves as an accurate representation of existing coal-fired power plants that may be candidates for CO_2 retrofitting. Unit 5 is a nominal 450 MW, pulverized coal-fired, subcritical pressure steam plant; with a 9,749 Btu/kWh (HHV) heat rate, a CO_2 emission rate of 1.0 ton/MWh, and a boiler in-service date of November 1, 1976. Post-capture costs, including CO_2 transportation, injection, and MMV are additional, with an assumed generic value of \$4/MTCO_2e[3].

Data Development

Cost data from the NETL study of the Conesville plant were restated in two important respects for conversion to a generic model and use in NEMS. First, costs were stated per unit of CO_2 removed, which provides a first order tie to a plant's specific heat rate for a given CO_2 removal level. Secondly, capacity and heat rate penalties were expressed separately for consistency with the capacity planning, fuel supply, and demand models in NEMS.

A key objective of the Conesville study was to look for a "sweet spot" where CO2 removal might be most cost effective in the range of 30 percent to 90 percent (presumably to balance economy of scale effects with reduced driving forces for mass transfer).

> Capital and O&M (Figs. 1 - 3) – Correlations were developed over the 30 percent to 90 percent removal range to preserve the option to assess the impact of CO2 removal level in NEMS. Economy of scale effects clearly dominate and minimums are not seen in any cost factor over the range of CO2 removals. Quadratic correlations resulted in only weak nonlinear terms. An apparent error in reported fuel usage for drying of CO_2 is excluded from the data.

[2] RDS, LLC, and Alstom Power Inc., "Sequestration for Existing Power Plants Feasibility Study," ME-AM26-04NT41817.401.01.01.003, Final Draft Report, Oct. 31, 2006.
[3] RDS, LLC, "Cost and Performance Baseline for Fossil Energy Plants – Vol.1, Bituminous Coal and Natural Gas to Electricity," DOE/NETL – 2007/1281, Final Report, May 2007.

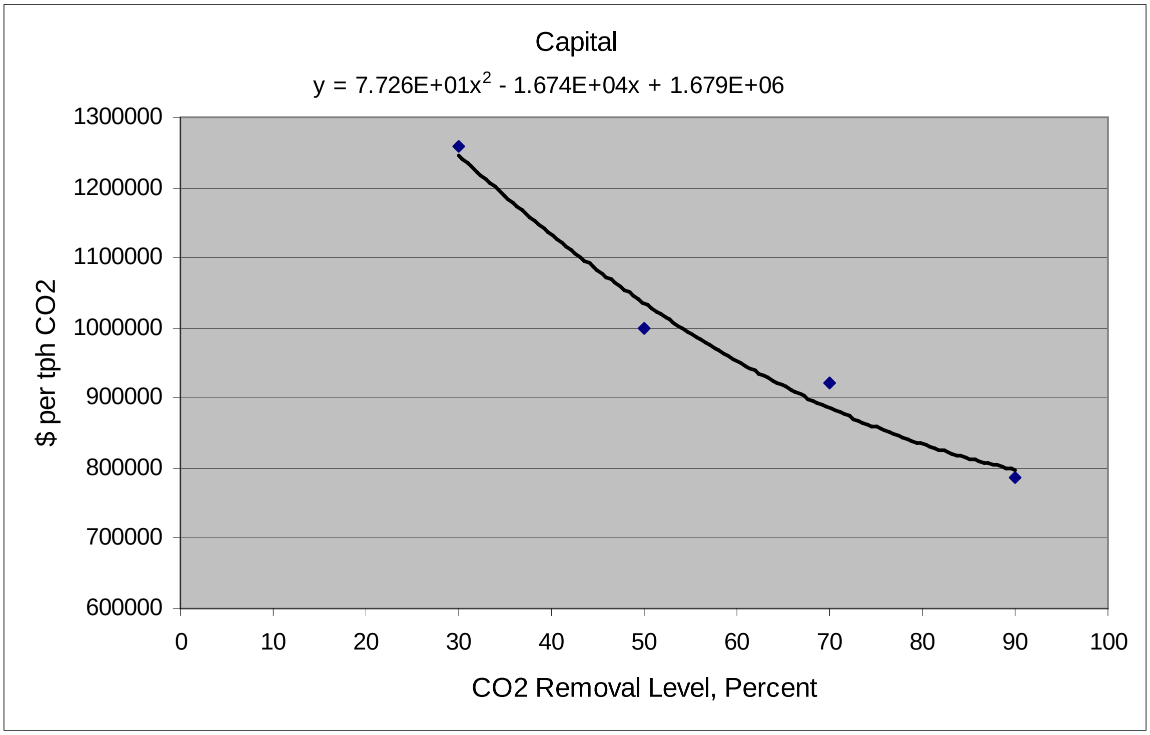

Figure 1: Capital costs show a marked economy of scale effect.

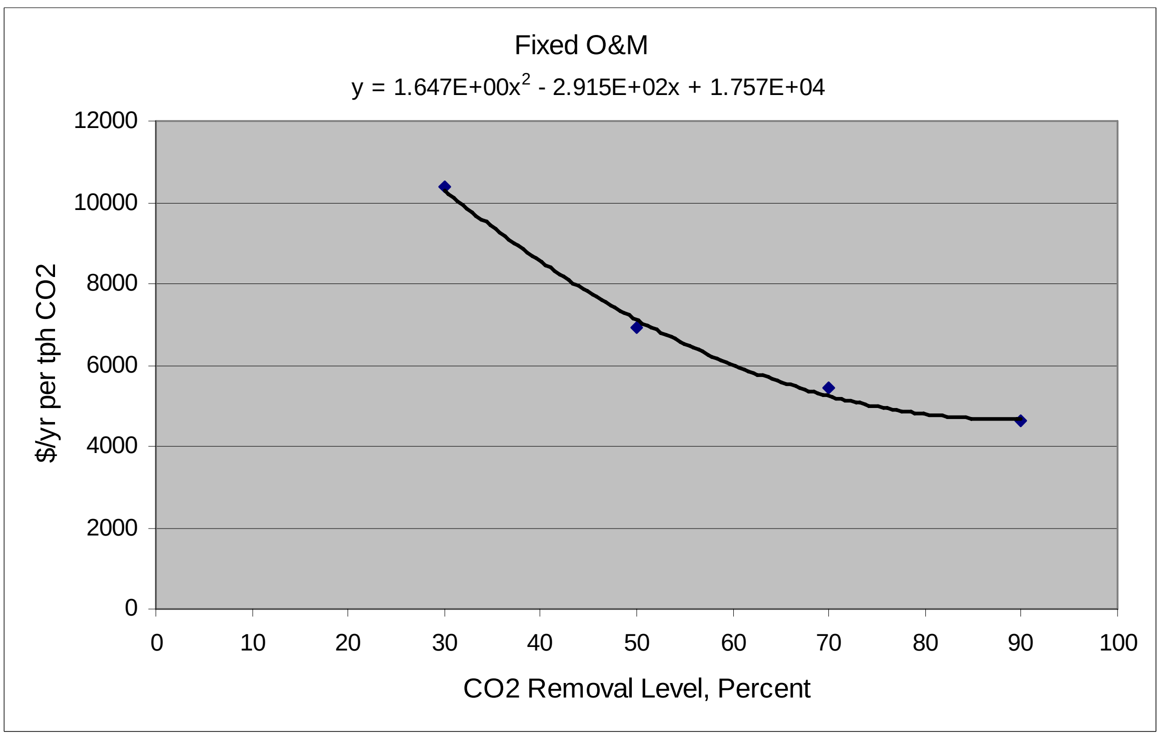

Figure 2: Fixed O&M costs also show a marked economy of scale effect.

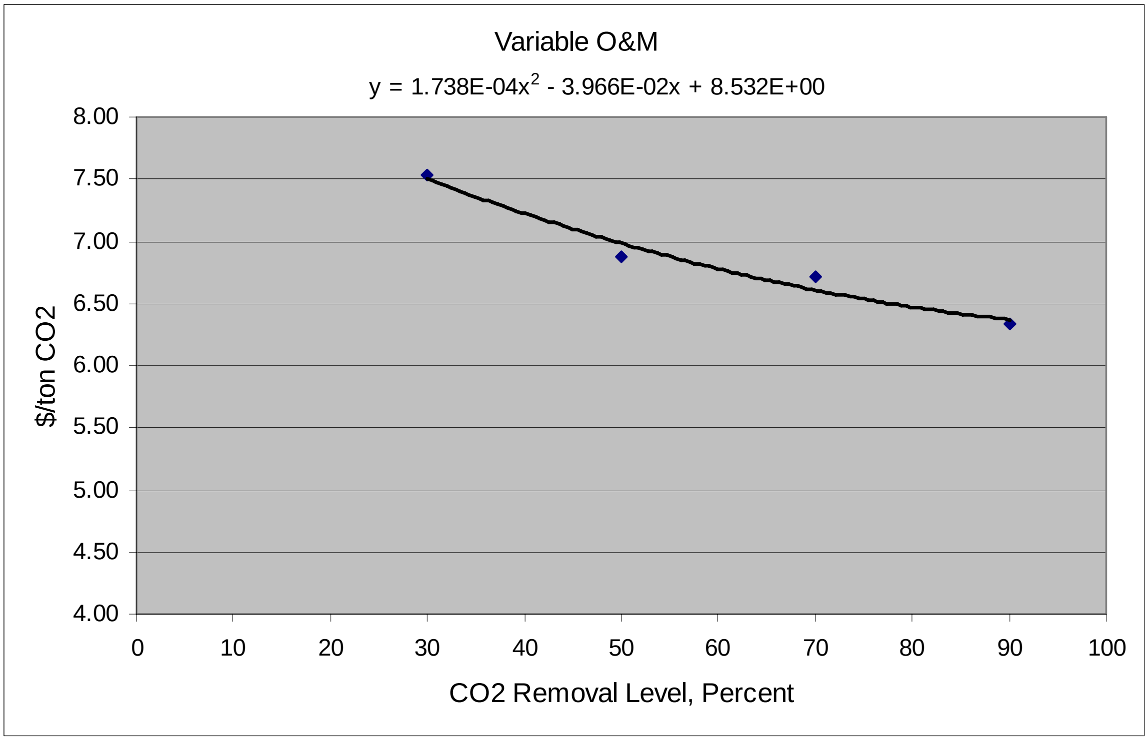

Figure 3: Variable O&M costs are not as scale dependent as Capital and Fixed O&M costs.

Capacity Penalty (Fig. 4) – A slight dependency on original heat rate was applied to generalize the Conesville data into the final form used in NEMS[4]:

CL = (α + β • OHR) • R

CL = capacity loss per unit of capacity retrofitted, kW/kW
OHR = original heat rate, Btu/kWh (HHV)
R = CO_2 removal level, percent (permissible values between 30 and 90)

The α-term accounts for extracted steam (largely for solvent regeneration):

α = m • C / η ≈ 0.0031 (Conesville study)
m = steam extraction requirement, MMBtu/ton-CO_2
C = fuel carbon content, ton-CO_2/MMBtu
η = boiler thermal efficiency, percent

The β-term accounts for net power consumption (net of power recovered from extracted steam), largely for CO_2 compression and liquefaction:

β = w • C • 1E−08 ≈ 0.025E-06 (Conesville study)
w = net power consumption, kWh/ton-CO_2

[4] The proposed dependency on heat rate is consistent with attributing differences in system heat rate to differences in steam cycle efficiency (i.e. assuming all plants have a boiler efficiency comparable to the Conesville plant) and a linear relationship between CO_2 removal level and net power consumption for CO_2 compression and liquefaction.

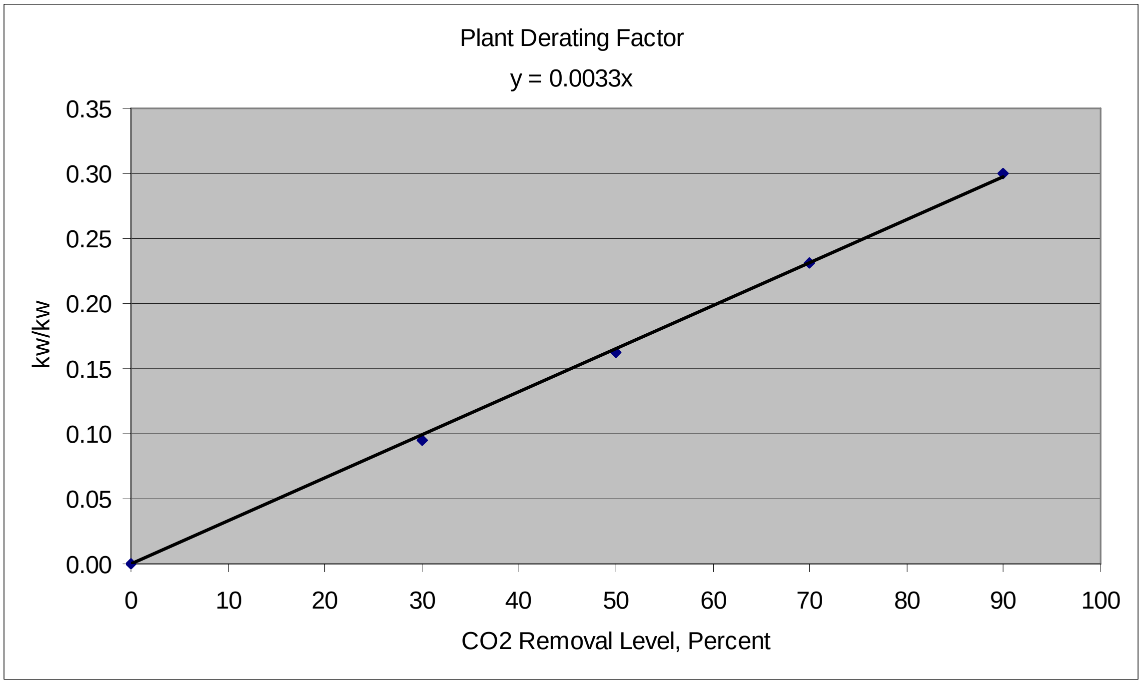

Figure 4: Plant Derating Factor - generally independent of plant heat rate, corresponding to the extraction of cycle steam for regeneration of CO_2 solvent (3.12 MMBtu steam per short ton of CO_2 captured).

> <u>Heat Rate Penalty</u> – In the advanced amine process designed by Alstom, power plant (boiler) fuel consumption is unchanged as a result of CO_2 capture, with the result that heat rate and capacity penalties are coupled:
>
> HRP = FHR / OHR = 1 / (1 – CL)
>
> > HRP = heat rate penalty
> > FHR = final heat rate, Btu/kWh (HHV)

The above correlations are ultimately translated by NEMS into a range of costs per unit of CO_2 captured or per unit of electricity, depending upon plant characteristics such as capacity factor, capital recovery factor, cost of replacement power, and carbon emission rate (a function of fuel carbon content and heat rate). To illustrate the variability caused by plant factors (Figs. 5 - 6), the contrasts are compared in a worst case versus best case scenario:

> Capacity Factor = 0.6 to 0.9
> Capital Recovery Factor = 0.10 to 0.15
> Cost of Replacement Power = 0.02 to 0.06 \$/kWh[5]
> Carbon Emission Rate = 0.85 to 1.5 ton-CO_2/MWH

[5] Cost of replacement power is used here in the sense that the capacity planning model in NEMS is constrained to meet minimum reserve capacity requirements and so will necessarily replace lost capacity with new capacity in the aggregate. The requirements of an individual utility in connection with capacity deratings is not the issue here.

It is important to note the above parameters are determined endogenously in NEMS. The scenarios presented here are intended to give an idea of the likely range in prospects for retrofitting across the fleet, as represented in the existing plant database of NEMS.

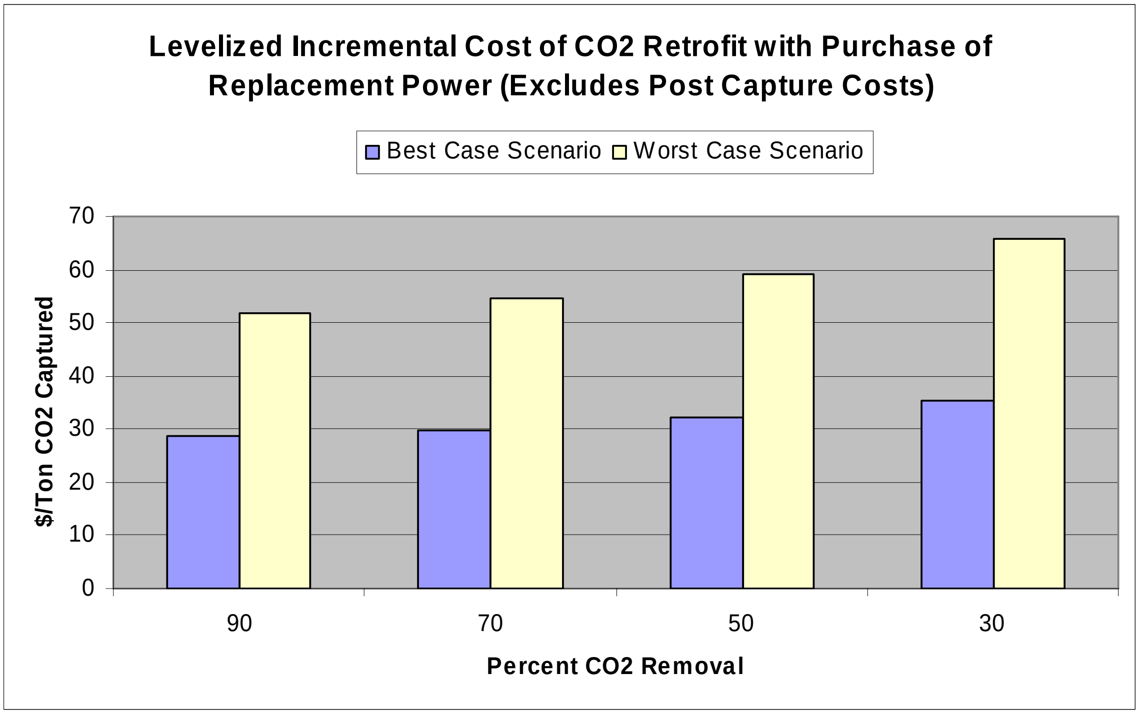

Figure 5: Total capture cost per unit of CO_2 captured decreases with CO_2 removal level.

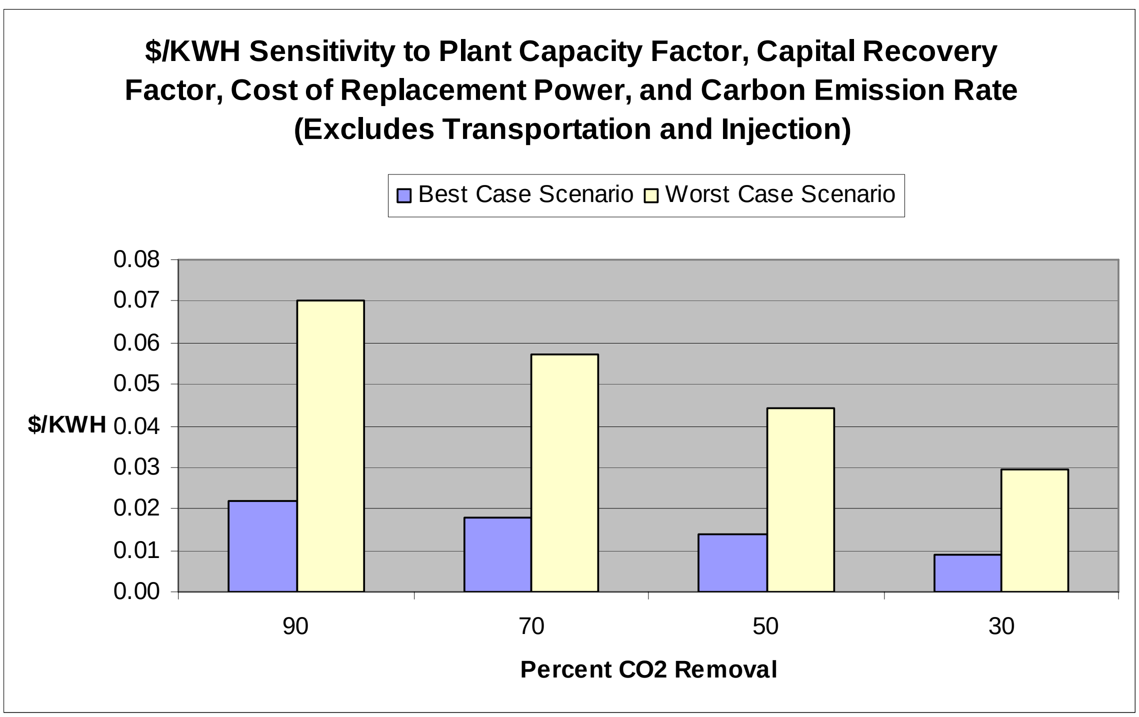

Figure 6: Total capture cost per unit of electricity increases with CO_2 removal level.

Model Development

NEMS does not include a retrofit model for CO_2 capture and sequestration, so the only options for coal plants in carbon-constrained scenarios are either the purchase of CO_2 emission allowances or retirement and replacement by technologies with lower carbon emissions. To do an integrated analysis of the prospects and impacts of retrofit technologies for various carbon constraint scenarios, certain modifications to the NEMS code and input files were needed; but it was possible to stay within the existing modeling structures of NEMS. The modifications effectively extended the existing NEMS retrofit algorithm from a 3-P (three pollutant—sulfur oxides, nitrogen oxides, and mercury) to a 4-P formulation (the fourth pollutant being carbon dioxide) by adapting an unused option originally intended for mercury control, known as "spray cooling" (retrofit for mercury control is addressed in NEMS by a separate "fabric filter" option).

<u>Code Changes</u>
UECP.F – Changes were confined to the two subroutines EP$COAL and EPO$COAL. To avoid revisions of input data file structures, generic retrofit cost correlations were embedded in the code. The correlations took the following form to conform to NEMS conventions on units (1987_$/kW, 1987_$/kWh) and to relate costs to CO_2 capture level and plant characteristics, of which the most important aspect is heat rate:

ICF = CF • OHR • (Z /1E06) • (R/100) • (1/MC_JPGDP(2006))

CF = cost factor correlations from Figs. 1 - 3 {2006_$/tph, 2006_$/ton}
ICF = incremental cost factors of CO2 retrofit {1987_$/kW, 1987_$/kWh}
MC_JPGDP(2006) = GDP price deflator (1987 = 1.0) = 1.532
Z = average carbon content of fuel, tons CO_2/MMBtu (HHV)[6]

Each of the above incremental cost factors was added to the corresponding retrofit cost categories wherever a CO_2 retrofit was indicated as part of a retrofit package in the code. Similarly, several constraint row and free row coefficients were revised to account for capacity and heat rate penalties wherever a CO_2 retrofit was indicated in the code.

<u>Input File Changes</u>
EMMCNTL.TXT – Changes were confined to three blocks of data: (1) retrofit options (new total and new options); (2) plant configurations (new total and new configurations); (3) and "spray cooler" input (revised sense of variables UCL_SC_O = Percent CO_2 Removal and UCL_SC_F = Transportation, Injection, and MMV, 2006_$/MT$CO_2$e).

Retrofit options and plant configurations were developed by adopting a "Retrofit Rule," which was chosen to limit the combination of retrofit technologies to a relevant subset. Two retrofit rules were examined. The simpler G1 rule restricts CO_2 retrofit to plants already in complete 3-P configuration. G1 requires only 1 additional retrofit option (addition of the CO_2 retrofit). G2

[6] Average values for the US are 0.103 (bituminous), 0.106 (subbituminous), and 0.108 (lignite); source: http://www.eia.doe.gov/cneaf/coal/quarterly/co2_article/co2.html.

allows for CO_2 retrofit to any plant as long as the missing 3-P components are added as well, but this rule requires 24 additional retrofit options.

Twelve new plant configurations, reflecting complete 4-P configurations, were required with either the G1 or G2 rule. As part of the rationale for G1 and G2, at least some measure of advanced sulfur control is deemed necessary in solvent-based process designs for CO_2 capture.

Results presented herein were all developed using the G2 rule.

ECPDAT.TXT – Pending a work around, certain changes were also needed in this file and care must be taken to maintain these consistently with those in EMMCNTL.TXT. Specifically, the UPPCEF and UPSCPEN inputs for CO_2 retrofit ECP types must reflect the CO_2 removal level and the implied capacity penalty specified in EMMCNTL.TXT (i.e. UCL_SC_O).

Sensitivity Studies

Sensitivity studies were completed to analyze whether the adaptations described above enable NEMS to select retrofit rather than retirement or the purchase of emission allowances if retrofit economics are sufficiently attractive. The costs excluded from these tests include capacity and heat rate penalties, as well as adders for transportation, injection, and MMV. Results of these studies are summarized in the Appendix.

One series of tests used a fairly severe carbon cap formulation of the AEO 2006, designed to limit electric utility emissions to about 1 billion $MTCO_2e$ in 2030. Retirements of coal plants through 2030 fell from about 150 GW to about 80 GW, with further reductions to below 20 GW with an incentive for CO_2 retrofitting (equivalent to the carbon emission allowance price). Retrofitted capacity through 2030 ranged from a little more than 100 GW (without the incentive) to over 300 GW, comparable to the initial fleet capacity in 2005.

In another series of tests, completed using a carbon tax version of the AEO 2007, the CO_2 retrofit option was observed to compete primarily with simple purchasing of emission allowances at 30 $/MTCO_2e$ and with retirements at 45 $/MTCO_2e$. A significant reduction in utility emissions occurred with the retrofit option at 30 $/MTCO_2e$. As in the previous series, nearly complete retrofit of the fleet resulted from artificially low retrofit costs.

In both series of tests, reductions in retirements were accompanied by reductions in the builds of carbon neutral technologies, most notably nuclear. In the carbon cap test, nuclear builds through 2030 fell from about 120 GW without the retrofit option to less than 50 GW with the option. In the 45 $/MTCO_2e$ carbon tax test, the corresponding nuclear builds fell from above 350 GW to about 100 GW. This is not unexpected since direct extrapolation of the AEO 2007 assumptions to carbon control strategies are known to favor new nuclear builds[7].

[7] Energy Information Administration, "Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007," SR/OIAF/2007-04, July 2007.

Results & Analysis

All cost factors from the generic retrofit cost model were included in a final series of tests with the carbon tax version of the AEO 2007. Costs now included capacity and heat rate penalties and adders for transportation, injection, and MMV. Carbon emission tax profiles were chosen on the basis of similar profiles planned for use in analysis of DOE research and development program benefits (Fig. 7)[8].

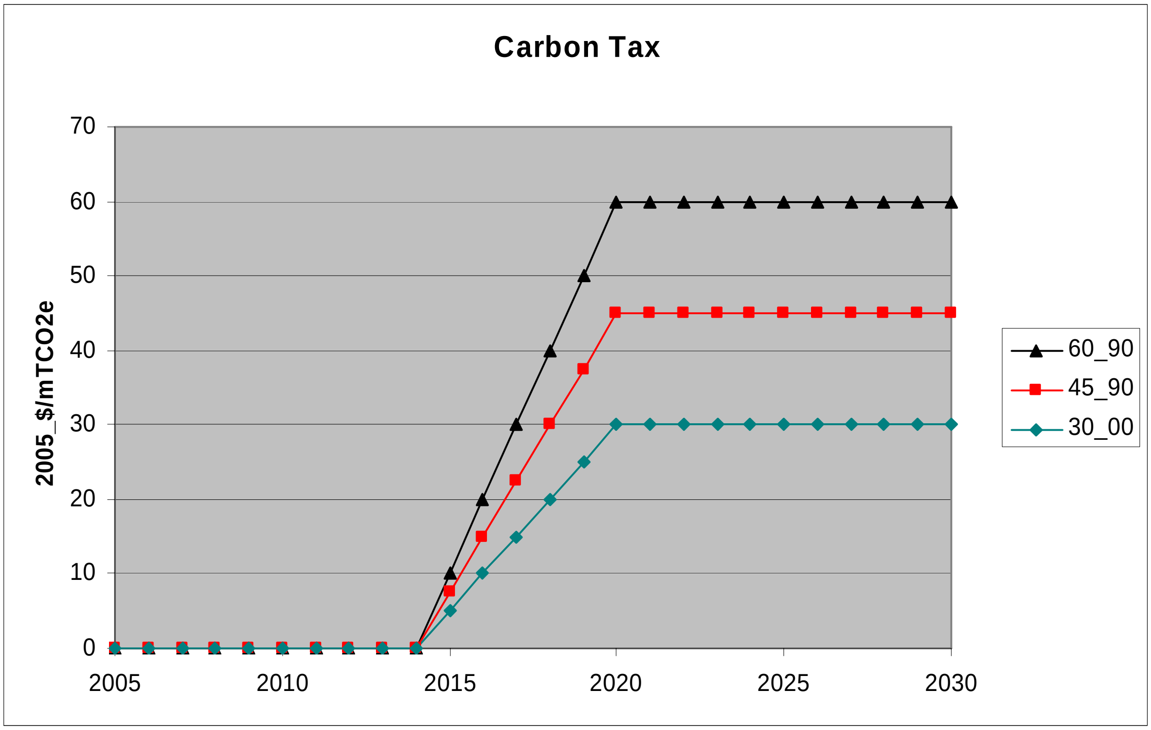

Figure 7: Carbon Tax. Profiles assume a linear ramp up between 2014 and 2020.

<u>Penetration and Impact of the CO_2 Retrofit Option at Various Carbon Values</u>

As might be expected, the penetration of CO_2 retrofits across the fleet and its effects on plant retirements, CO_2 emission levels, and builds of carbon neutral capacity were impacted by the carbon emission tax level. The 45 \$/MTCO_2e case was observed to represent a threshold for adoption of the retrofit option, below which it was preferable to purchase emission allowances, as in the 30 \$/MTCO_2e case (Fig. 8).

[8] Legend entries of the type 30_90 signify 30 \$/MTCO_2e and 90 percent CO_2 removal.

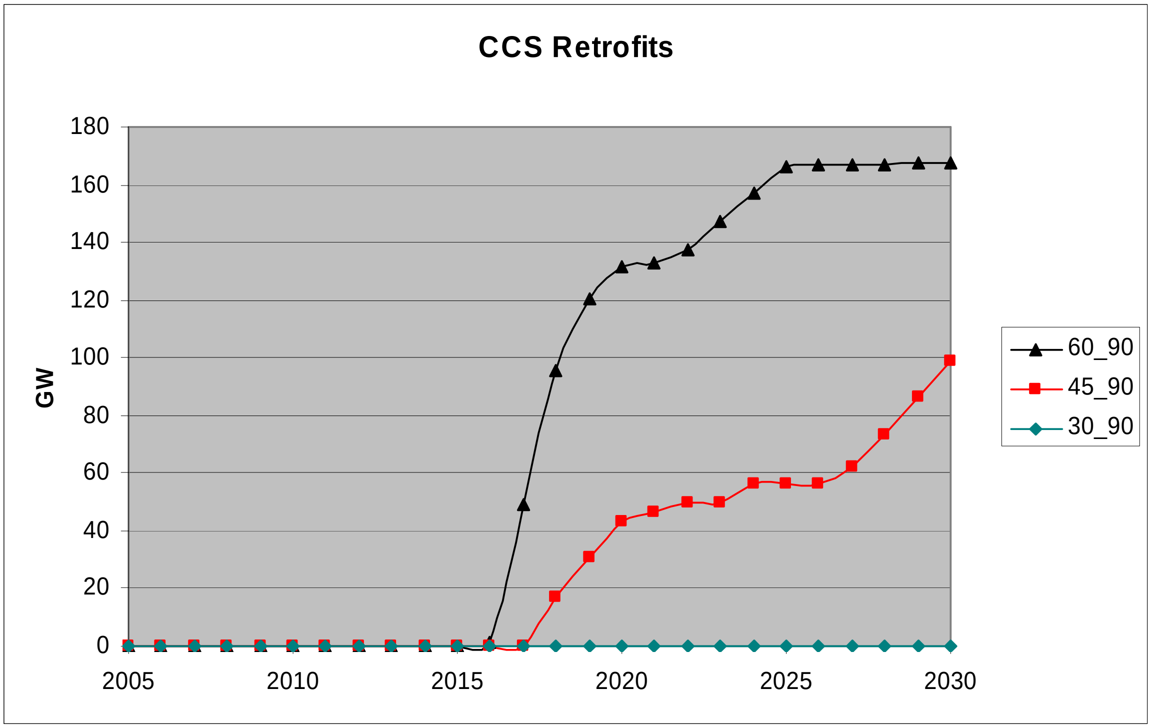

Figure 8: CO_2 Retrofits. A possible need to model sustainable deployment rates is suggested by rates as high as 50 GW per year in the 60 $/MTCO_2e case.

It should be noted that capacity retirements as reported by NEMS include both capacity deratings of retrofitted plants and actual plant retirements (Fig. 9). At 45 $/MTCO_2e, capacity deratings through 2030 are 30 GW, corresponding to the 30 percent derating factor for the 90 percent CO_2 removal levels used in this study. At 60 $/MTCO_2e, capacity deratings increase to about 50 GW. Factoring in these capacity deratings, the impact of the retrofit option on actual plant retirements is as shown in Table 1. Hence, 128 GW of plant retirements are avoided by the retirement option at 45 $/MTCO_2e, while 1149 GW are avoided at 60 $/MTCO_2e.

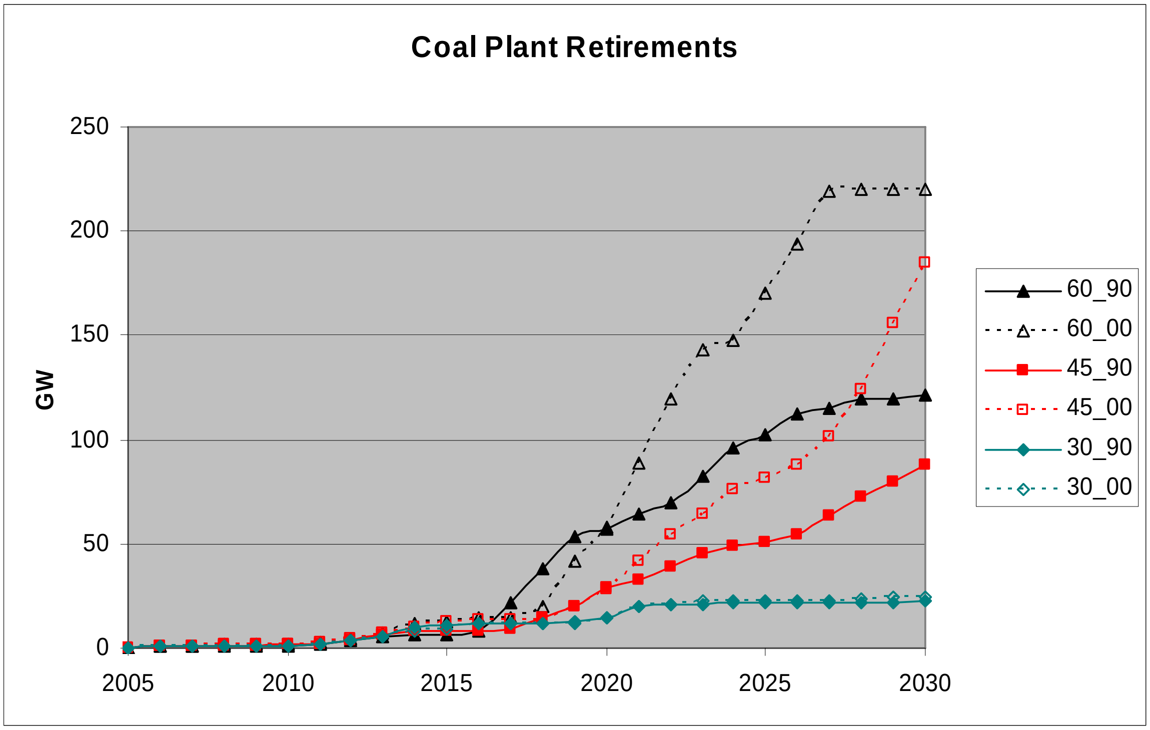

Figure 9: Coal Plant Retirements. Retirements include capacity lost (derating) due to retrofits – approximately 30 GW and 50 GW by 2030 for the 45 and 60 \$/MTCO$_2$e cases, respectively.

Table 1: Impact of the CO2 Retrofit Option on Retirements Depends Upon CEA.
(Capacity Retirements = Retrofit Deratings + Plant Retirements)

GW, Cumulative Through 2030	Carbon Emission Allowance Price, \$/MTCO$_2$e	
	45	**60**
Plant Retirements Before Retrofitting	185	220
Original Capacity Retrofitted	100	167
Retrofit Deratings	30	50
Capacity Retirements After Retrofitting	87	121
Plant Retirements After Retrofitting	57	71
Avoided Plant Retirements	128	149

The impact of the CO_2 retrofit option on new builds of lower carbon emission or carbon neutral capacity is a reflection of impacts on coal plant retirements (Fig. 10). At 60 $/MTCO$_2$e, nuclear builds through 2030 fell by about 100 GW. At 45 $/MTCO$_2$e, they fell by about 120GW.

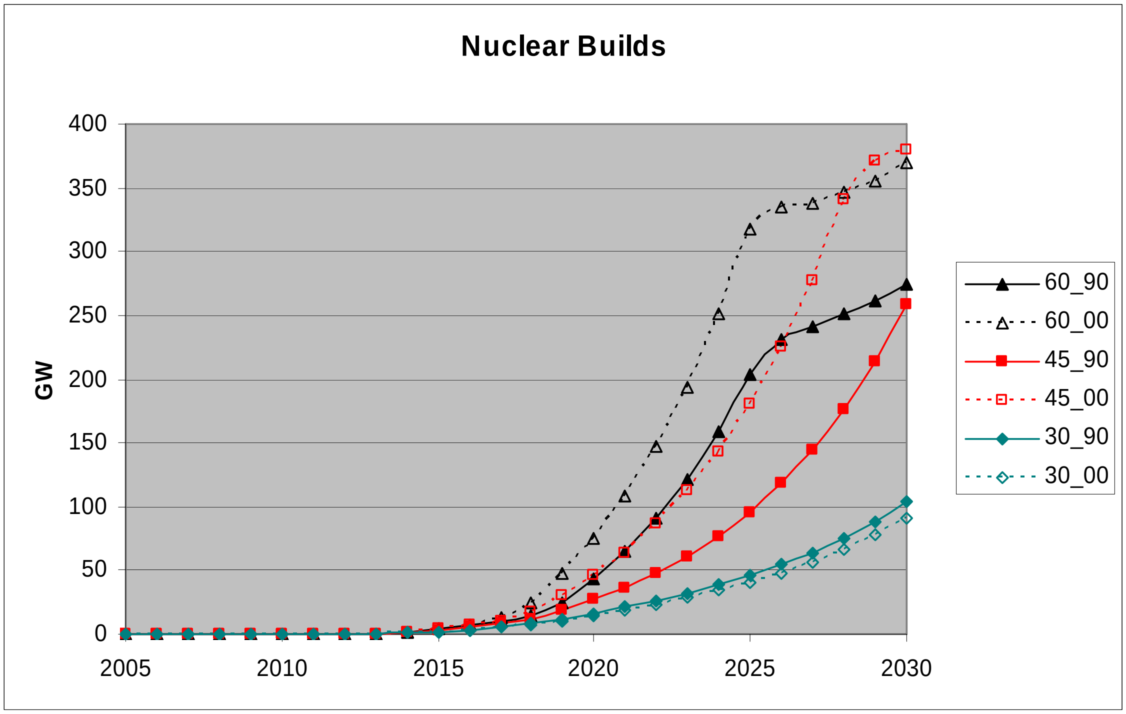

Figure 10: Nuclear Builds. Carbon neutral capacity additions are impacted only at high carbon emission allowance prices where retirements of coal plants are a factor.

Since CO_2 retrofits offset the purchase of emission allowances at lower tax levels and the retirement of coal plants with replacement by lower carbon emission or new carbon neutral technologies at higher tax levels, the impact on utility CO_2 emissions could be different at different tax levels. In both the 45 $/MTCO$_2$e and 60 $/MTCO$_2$e cases, the pace of CO_2 emissions reductions over time is not substantially changed by the CO_2 retrofitting option (Fig. 11). In both cases, emissions in 2030 decline to levels ordinarily associated with extensive retirement of coal plants and deployment of carbon neutral technologies, but the decline is achieved through the alternative pathway represented by the retrofit option.

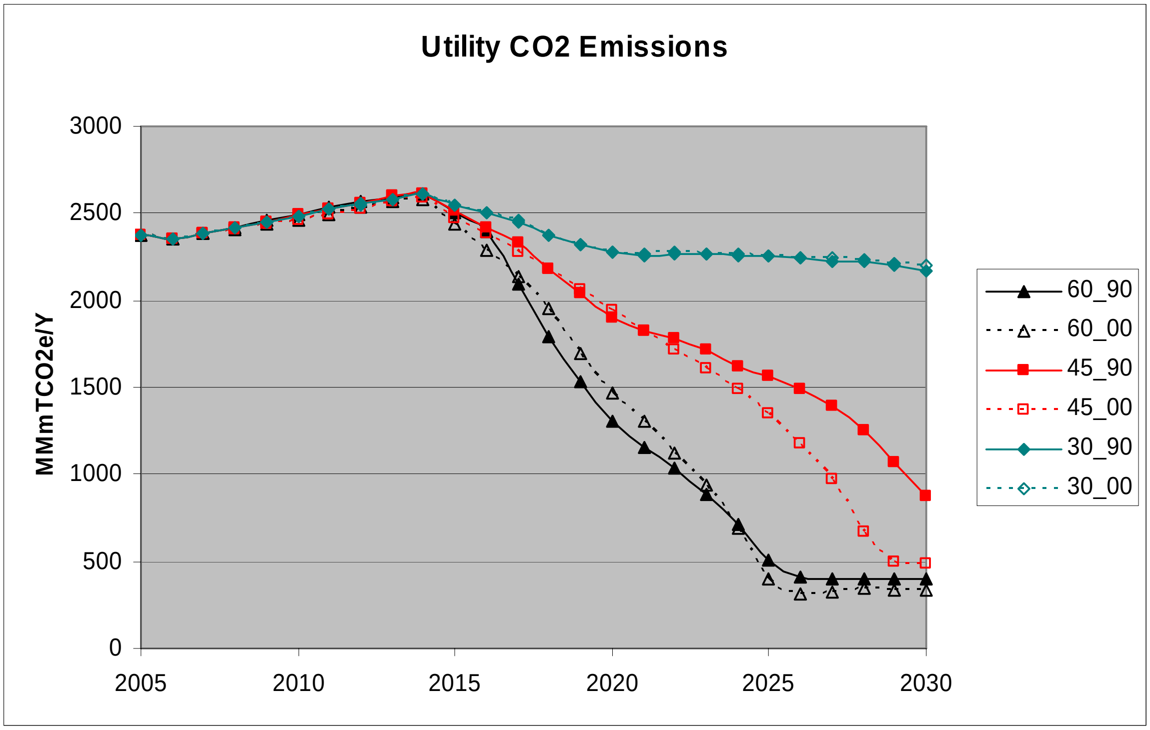

Figure 11: Utility CO_2 Emissions. At any given carbon emission allowance price, the retrofit option provides an alternative, generally equivalent path to reduced carbon emissions.

<u>Interpretive Model of the CO_2 Retrofit Decision</u>

A simple conceptual model based on selection of the option with minimum levelized cost of electricity is consistent with the foregoing trends (Fig. 12). Such a model suggests a minimum carbon emission allowance price (CEA) where retrofits would not be economic and a maximum CEA where retirements would be preferred, if an option to retrofit were unavailable. Between these limits would be an interval of CEA where retrofits would mostly impact emissions rather than retirements, while above this interval, the converse would occur.

However, two important qualifications should be noted. First, the decision model in Figure 12 is for a specific plant, while a fleet of plants involves a distribution of plants with different cost and performance factors. Hence, the penetration of CO_2 retrofits in a fleet should asymptotically approach an upper bound which increases with carbon value, as observed. Second, the cost of electricity (COE) of the competing new plant (that would replace the retiring plant) is a nominal value representing the mix of available technologies. Uncertainties in this COE ("new carbon neutral plant" COE in Fig. 12) imply uncertainties in the penetration by CO_2 retrofitting. If the nominal COE for the mix of competing new plants is higher, a greater portion of the fleet will be retrofitted (Fig. 13).

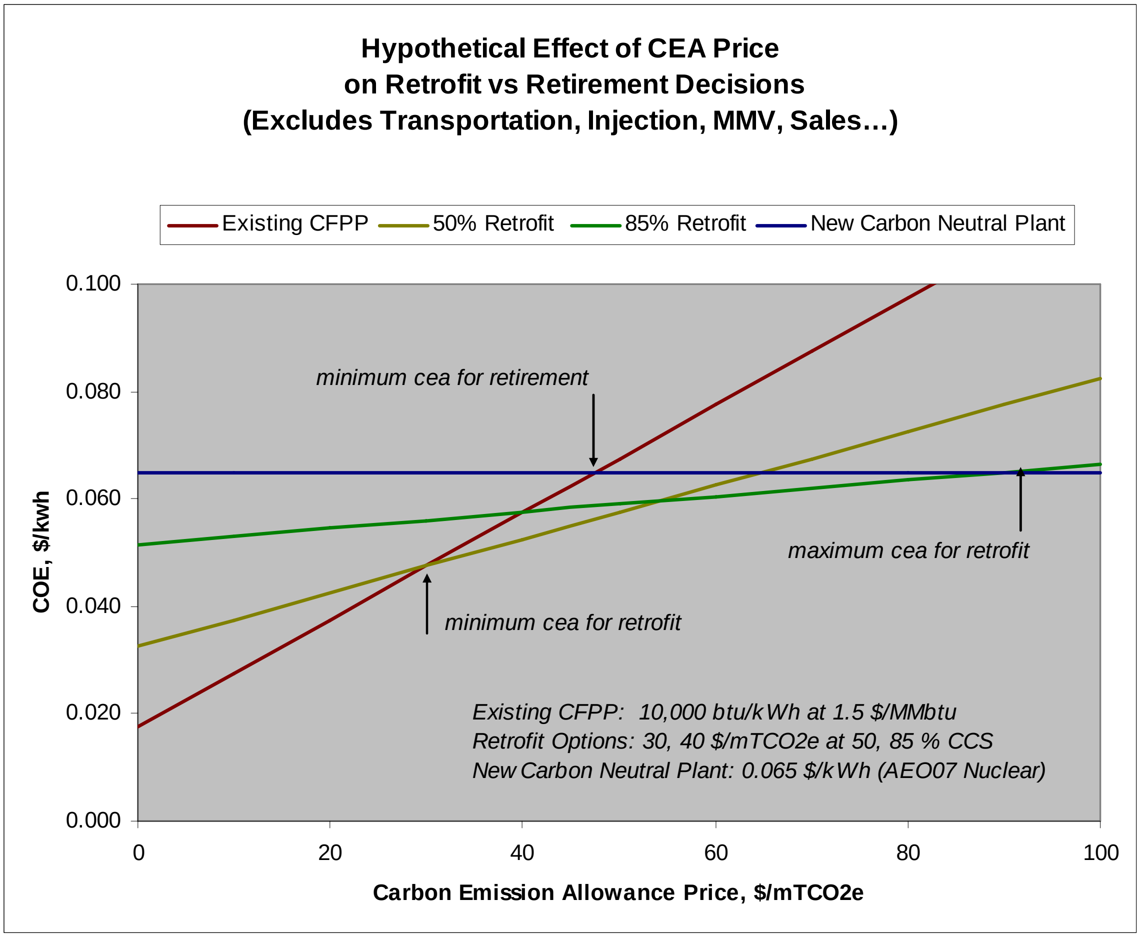

Figure 12: Hypothetical Effect of CEA Price on Retrofit vs. Retirement Decisions. The indicated critical CEA's depend upon cost and performance factors of the plant to be retrofitted (most notably heat rate and fuel cost) and the COE of the new carbon neutral plant that would be built to replace a retired plant.

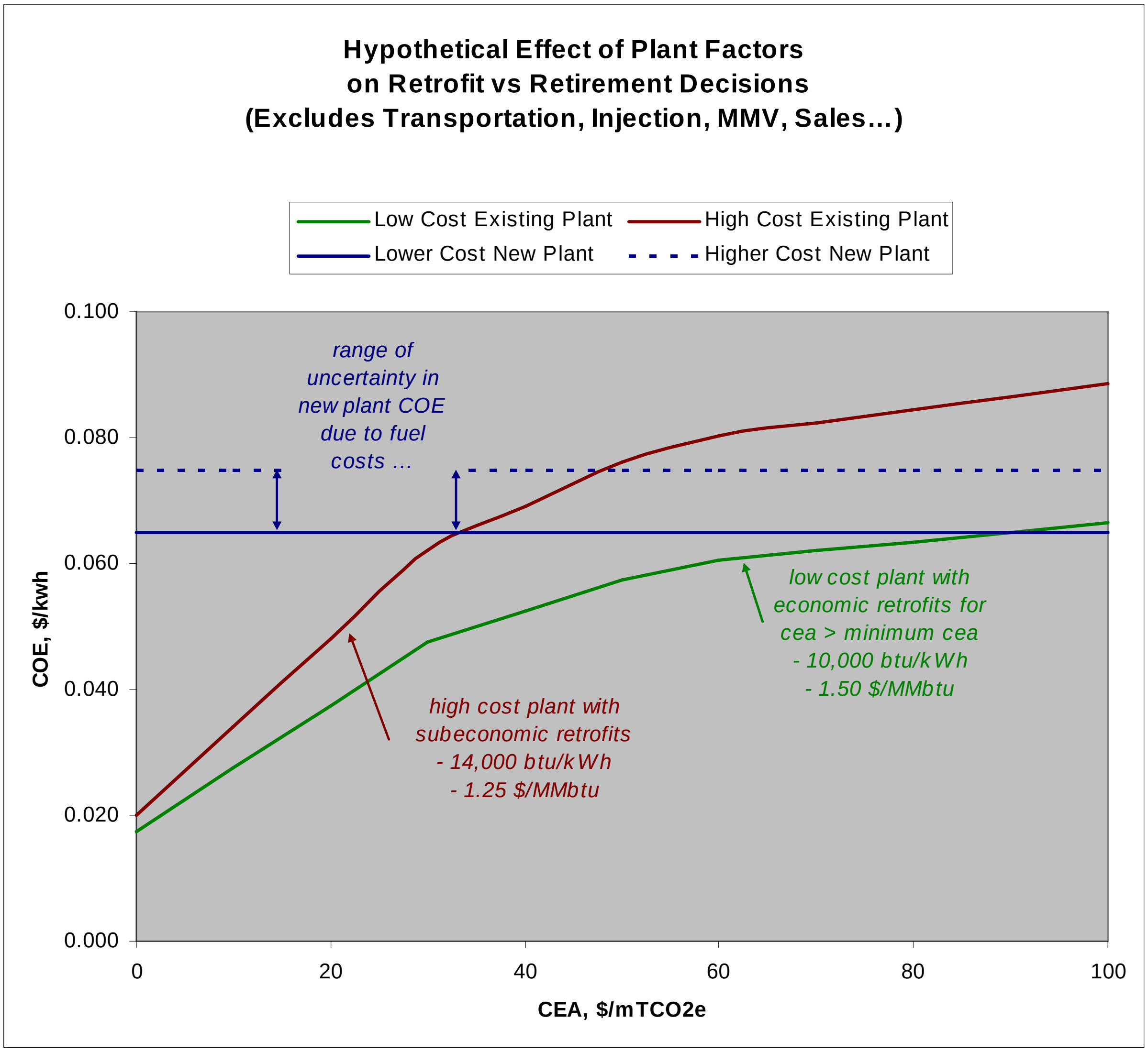

Figure 13: Hypothetical Effect of Plant Factors on Retrofit vs. Retirement Decisions. The proportion of plants in a fleet that could be retrofitted rather than retired depends on COE for new plants and associated uncertainties such as gas prices.

Uncertainties in CO_2 Retrofit Penetration – Impact of Natural Gas Prices

An important uncertainty in this regard is the price of natural gas since natural gas is a preferred fuel in carbon control scenarios (lower carbon content) and since there is a perception by many that pending globalization of the gas market makes any projection of gas prices inherently risky; some analysts believe that NEMS consistently under predicts natural gas prices[9]. The impact of higher gas prices was investigated by increasing the transmission tariff by 5 $/MCF for delivery to electric utilities, which had the expected impacts on price of delivered gas to electric utilities (similar to those in the AEO2007 high world oil price scenario), gas-fired capacity additions, and fossil fuel-fired retirements (Figs. 14 - 17)[10].

[9] Timothy J. Considine and Frank Clemente, "Do EIA natural gas forecasts contain systematic errors?," *20 Aug 2007 by ASPO-USA*; .source: http://www.energybulletin.net/33661.html

[10] Legend entries of the type 30_90_5 signify 30 $/MTCO$_2$e, 90 percent CO_2 removal, and 5 $/MCF gas price adder.

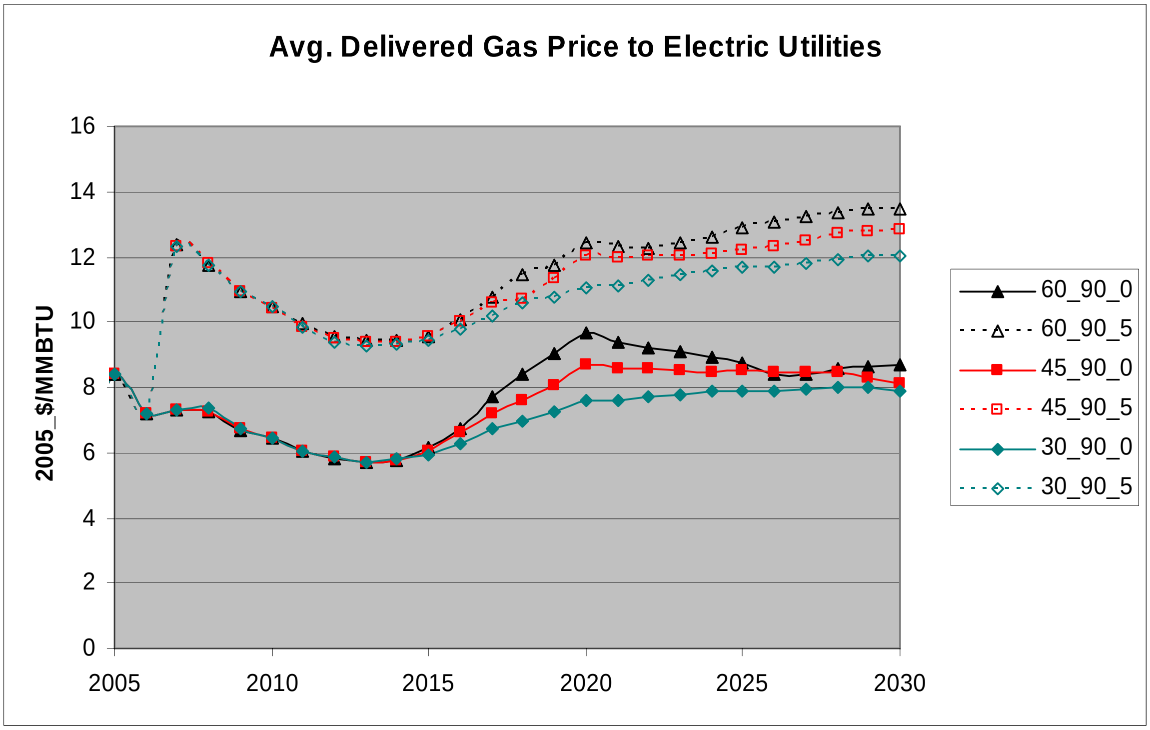

Figure 14: Average delivered price to the electric utility sector reflects the exogenous increase in gas prices and the impact of the CO_2 retrofit option.

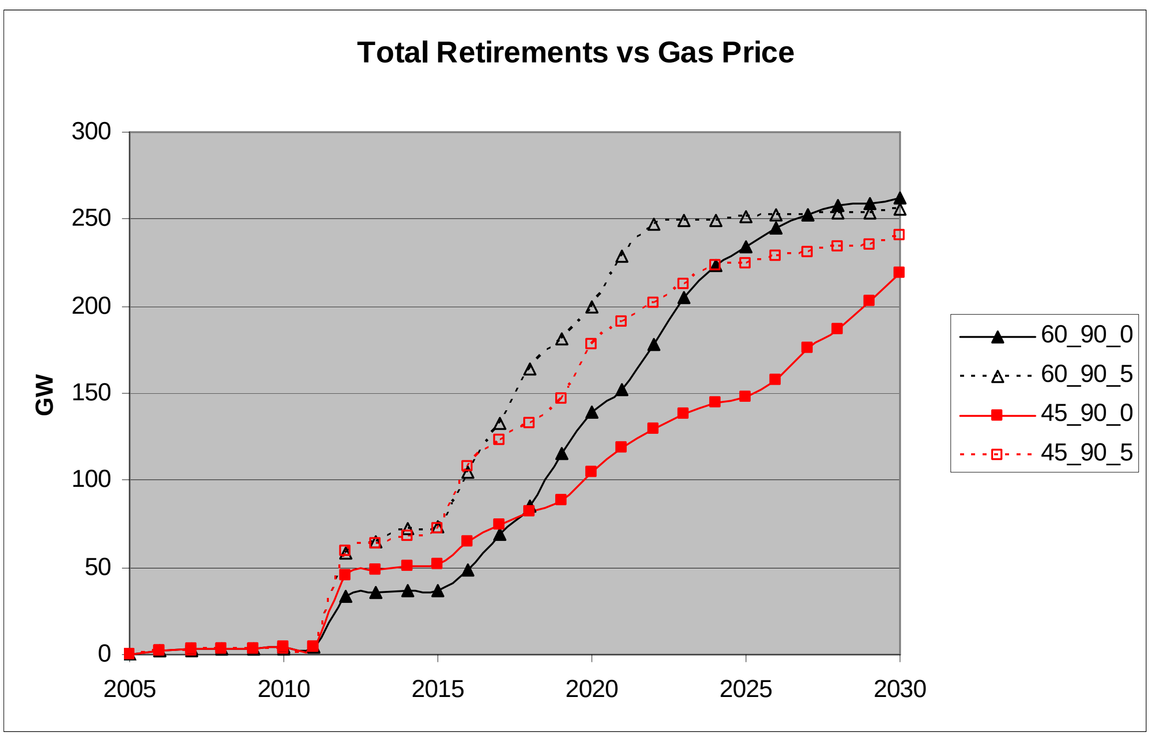

Figure 15: Total Retirements vs. Gas Price. "Total Retirements" refers to all fossil fuels and the increase in response to higher gas prices is largely a reflection of increased retirement of gas fired capacity.

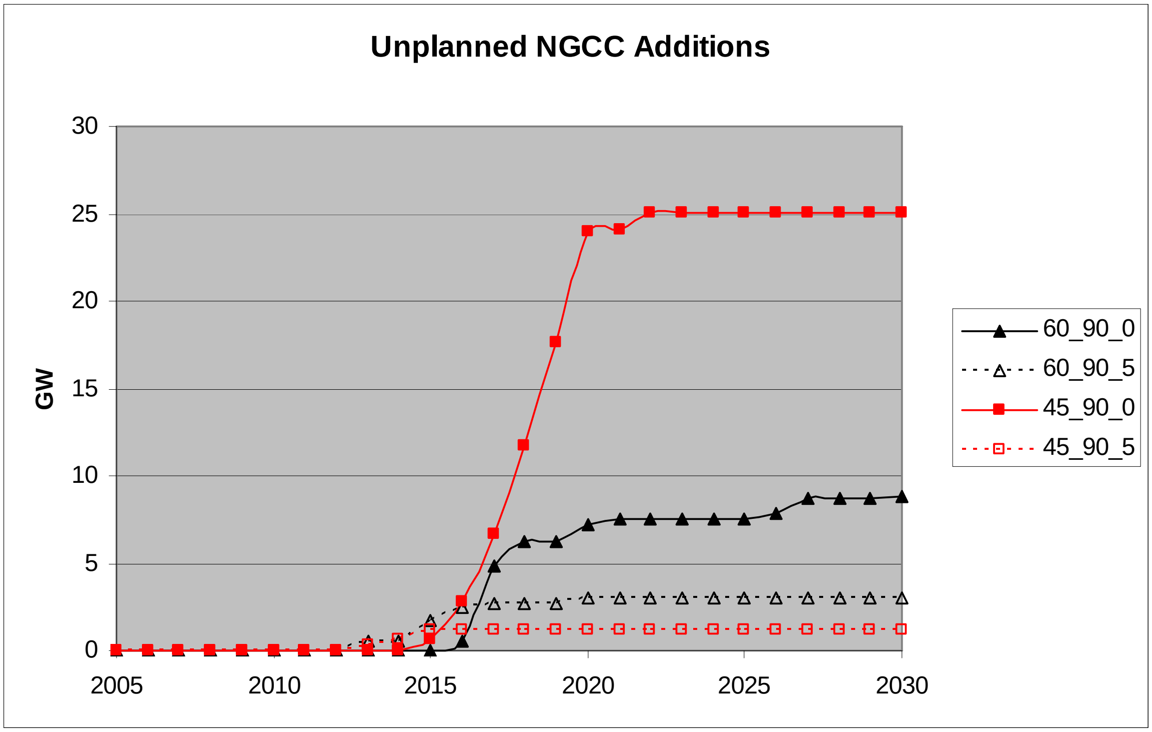

Figure 16: Unplanned NGCC Additions. New gas-fired capacity is nearly eliminated by higher delivered gas prices.

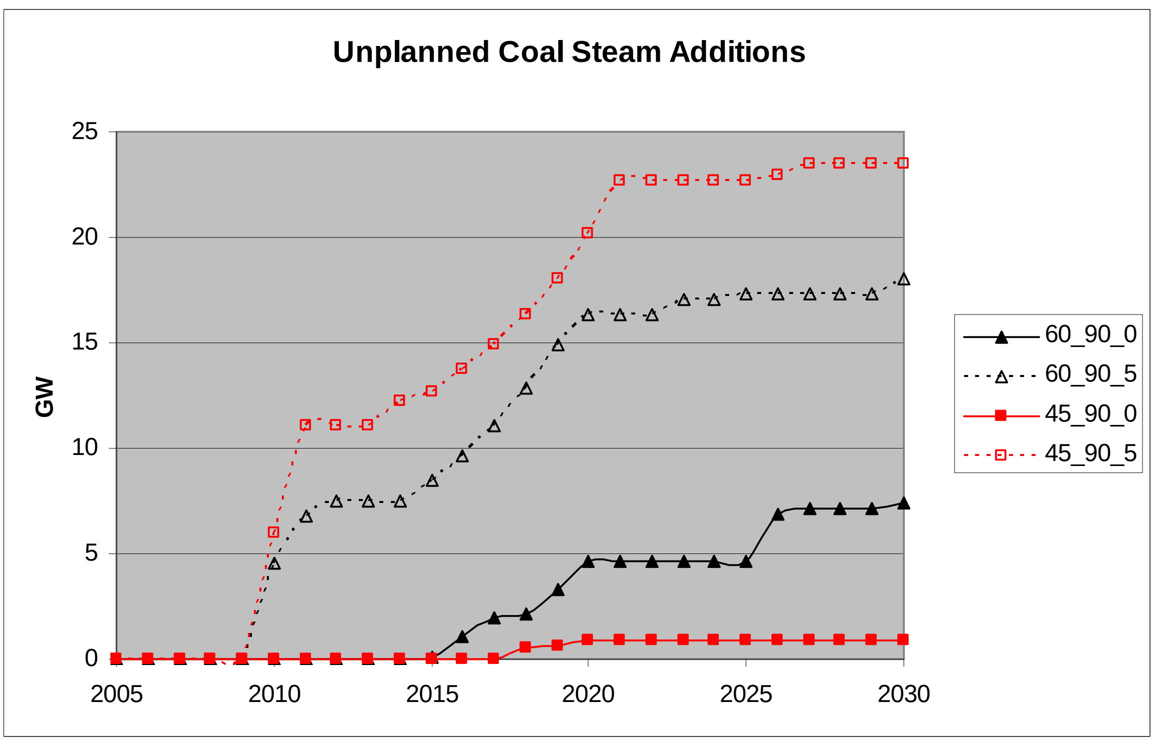

Figure 17: Unplanned Coal Steam Additions. Higher delivered gas prices increase the builds of new coal capacity.

The impact of higher natural gas prices on CO_2 retrofit penetration through 2030 depended on carbon value (Figs. 18 – 19). At 45 \$/MTCO_2e, CO_2 retrofits increased about 50 GW and coal plant retirements fell about 20 GW (allowing for 15 GW of capacity deratings from retrofits). At 60 \$/MTCO_2e, CO_2 retrofits increased about 80 GW and coal plant retirements fell about 45 GW (allowing for 25 GW of capacity deratings from retrofits). At 30 \$/MTCO_2e, CO_2 retrofits were only observed with the high gas prices (but only about 1 GW). At 15 \$/MTCO_2e, CO_2 retrofits were not observed at any gas price.

In the context of the interpretive model, 15 \$/MTCO_2e is lower than the minimum CEA for retrofitting any plant in the fleet relative to the purchase of carbon emission allowances; 60 \$/MTCO_2e is more than adequate for retrofitting most plants, but not all retrofits are competitive with retirement since the cost curve for retrofitted high-cost plants exceeds the nominal COE for replacement capacity. To the extent that gas-fired capacity is part of the mix of technologies for replacement capacity, the impact of gas prices would thus appear to reflect the distribution of plant cost and performance factors across the fleet.

In summary, two important uncertainties are apparent in the CO_2 retrofit penetrations observed in this study: (1) a generic retrofit cost model was used for all plants in the fleet without regard to site specific factors and (2) some baseline assumptions in the AEO 2007 may be inappropriate for high carbon value scenarios, especially those related to the role and price of natural gas and the elasticity of supply from new carbon neutral technologies like nuclear.

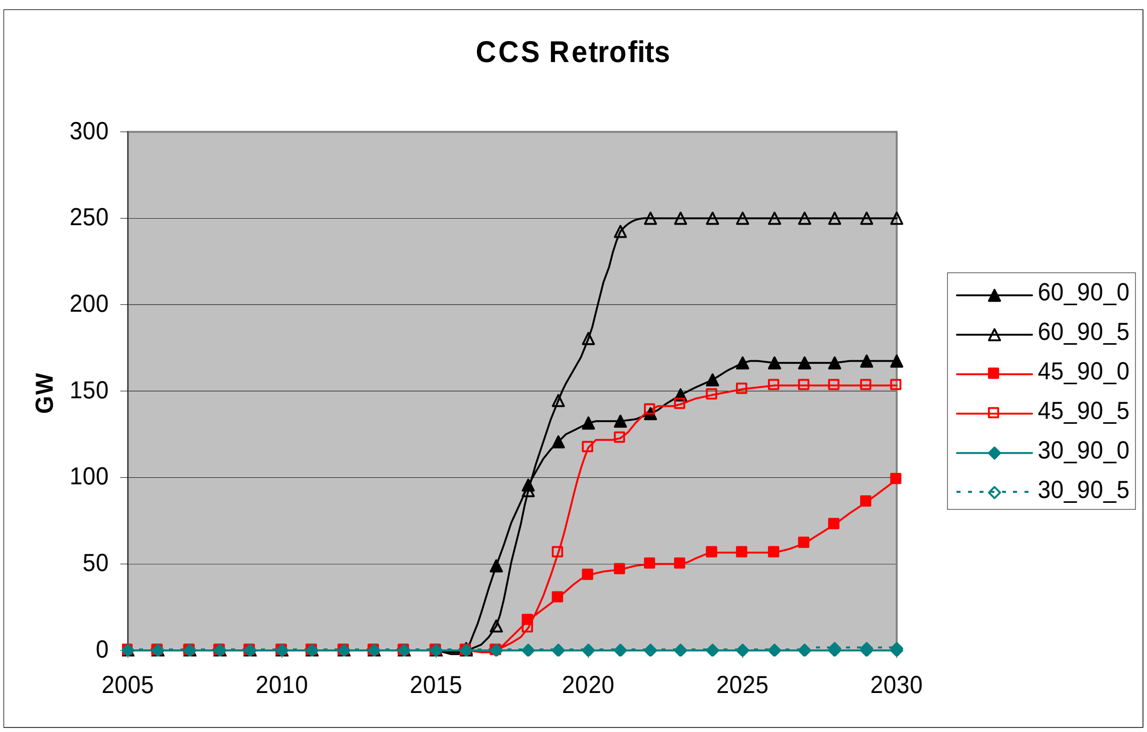

Figure 18: CO_2 Retrofits vs. Gas Price. CO_2 retrofits are significantly increased by higher gas prices, but only at high carbon emission allowance prices. At 30 \$/mTCO_2e, there are essentially no retrofits.

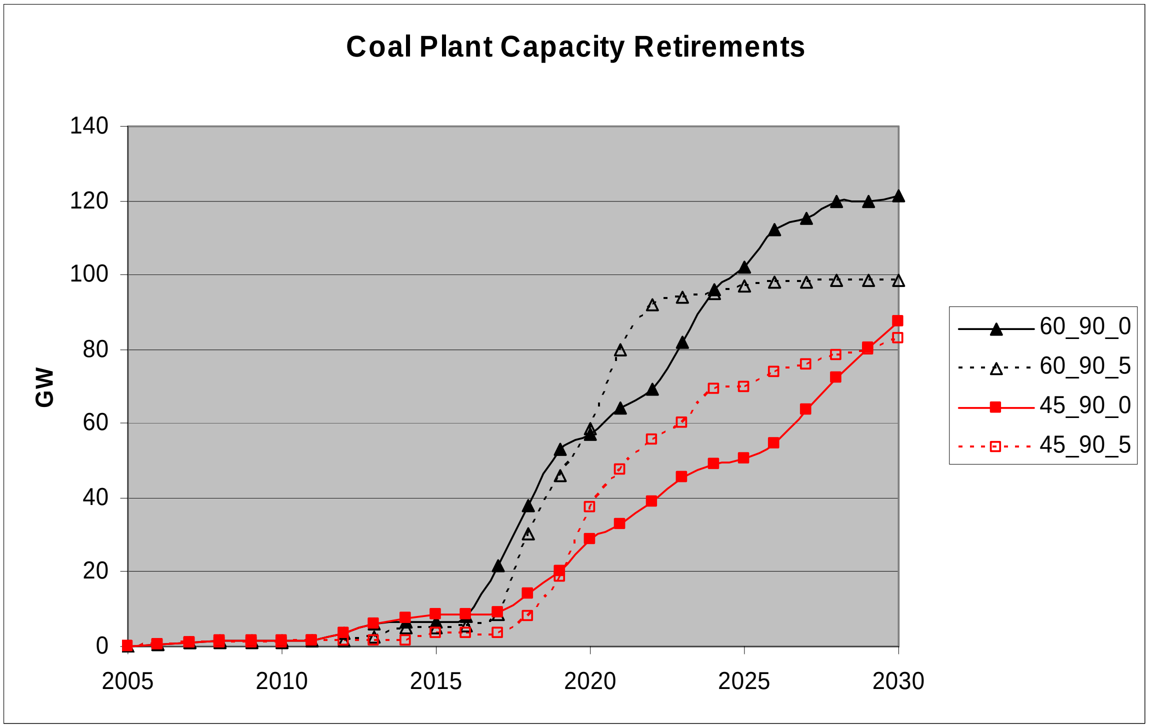

Figure 19: Coal Plant Capacity Retirements vs. Gas Price. Capacity retirements, the net of capacity deratings from CO_2 retrofits and avoided plant retirements, are reduced by higher gas prices.

Conclusions

A NEMS-based approach has been devised to perform integrated assessments of the prospects for retrofitting existing coal plants for CO_2 capture and sequestration. Sensitivity tests show the approach to be consistent with general expectations, including the notion that CO_2 retrofitting will be an expensive proposition relevant only at high carbon emission allowance prices. The penetration levels observed in this study are subject to uncertainties due to the use of a generic retrofit cost model and to underlying assumptions in the AEO 2007 which among other things may overestimate the role or underestimate the price of natural gas in high carbon value scenarios.

Notwithstanding these uncertainties, the required carbon emission allowance prices are not so high as to rule out the viability of CO2 retrofitting as a cost effective option in high carbon value scenarios. Since the retrofit cost model was based on current technology, R&D programs with significant benefits are plausible, and the approach used in this study could provide supporting metrics. While the underlying process used for cost data in this study was based on an advanced amine process for scrubbing stack gases, the approach should be adaptable to other retrofitting processes, including repowering concepts for carbon capture, such as Oxy-Combustion or Brownfield Integrated Gasification Combined Cycle technology.

Appendix - Sensitivity Tests

(Without Heat Rate or Capacity Penalties, or CO_2 Transportation, Injection, MMV, or Sales**)**

Carbon Cap (FECAP_06) – Figs. A1 – A4

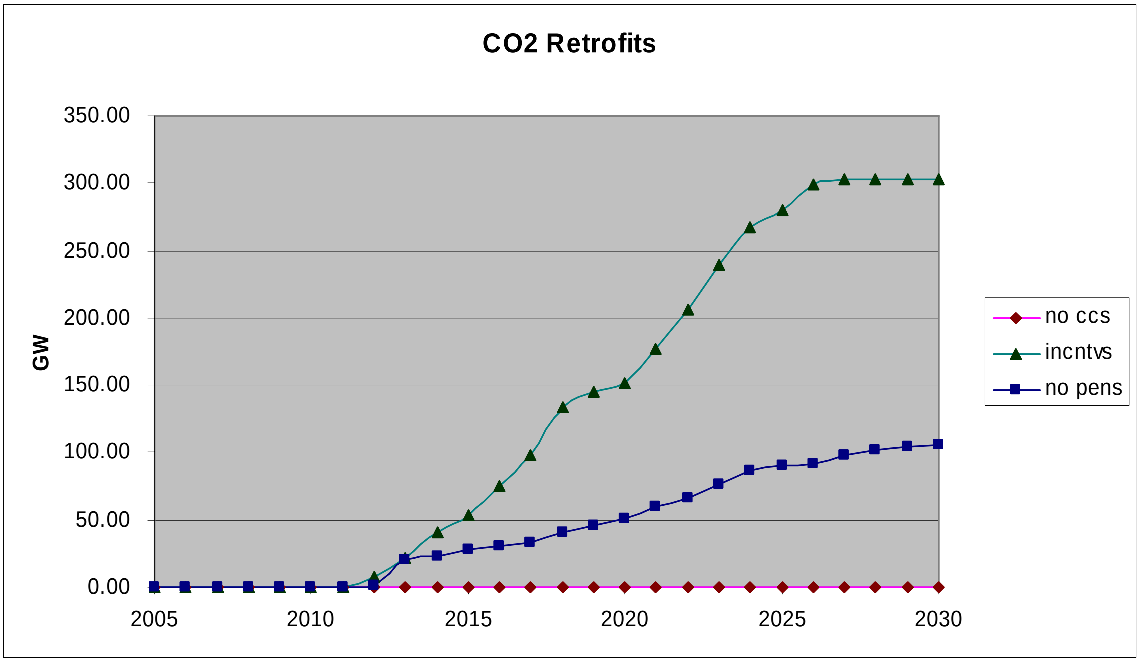

Figure A1: CO_2 Retrofits

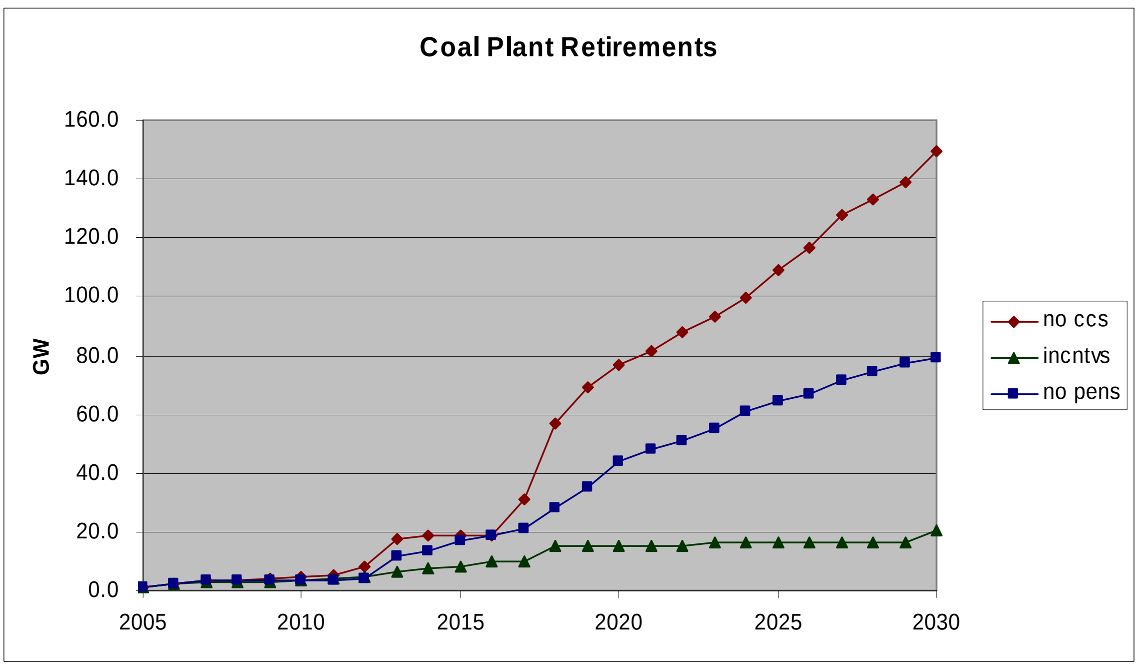

Figure A2: Coal Plant Retirements

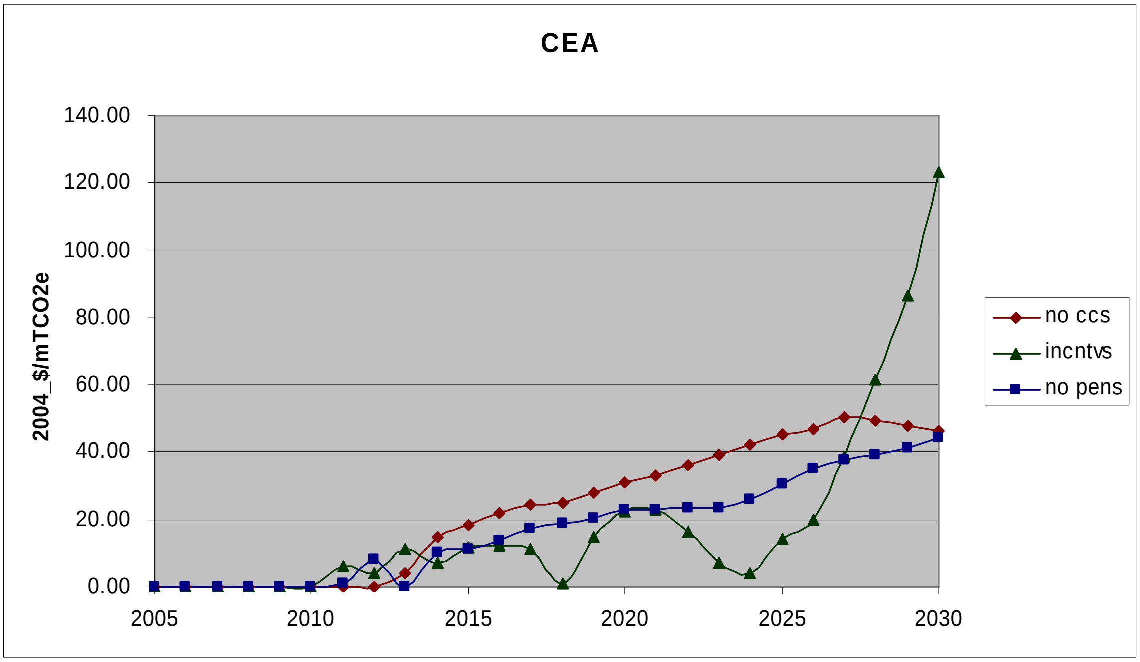

Figure A3: CEA

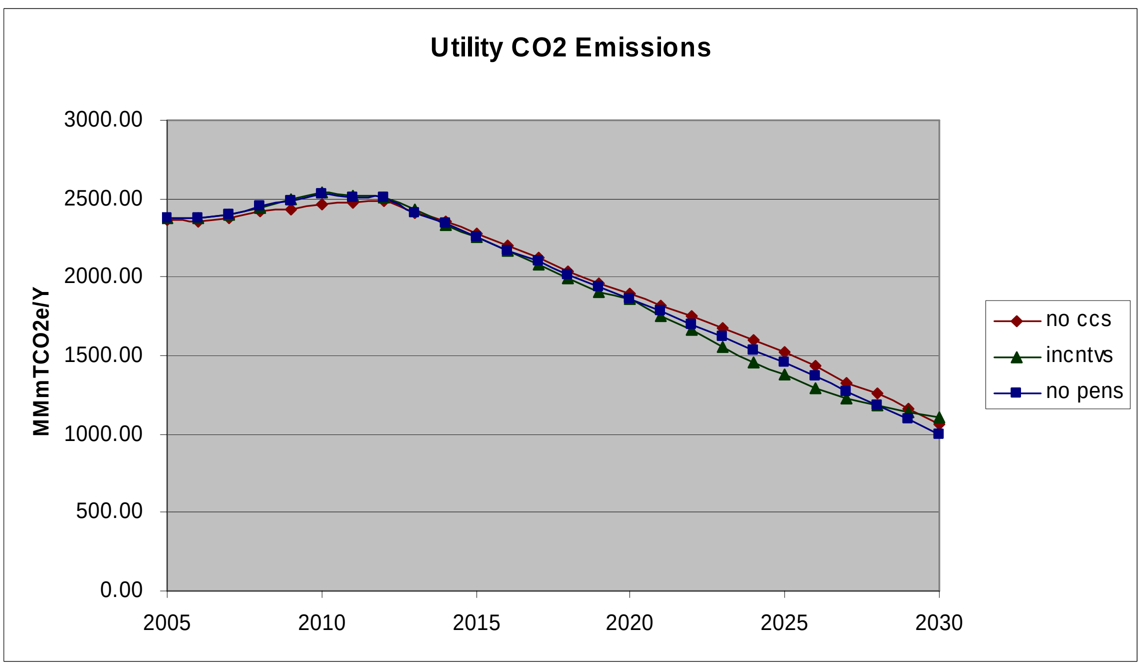

Figure A4: Utility CO_2 Emissions

Carbon Tax (AEO_CTX_07) – Figs. A5 – A8

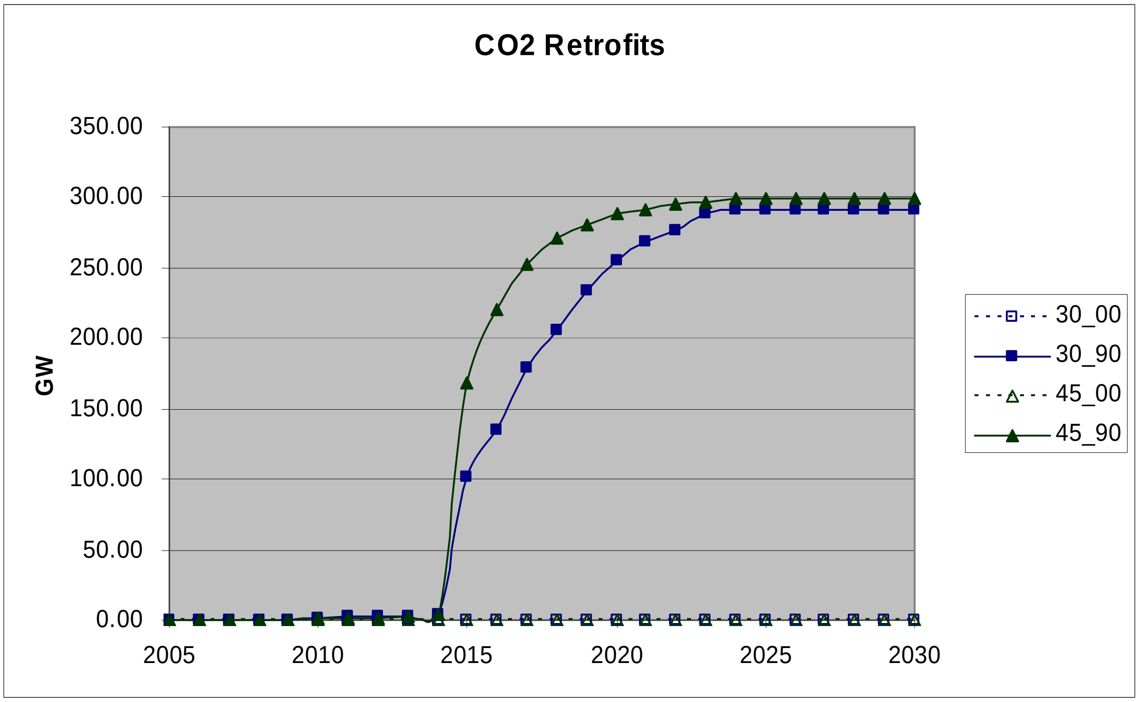

Figure A5: CO_2 Retrofits

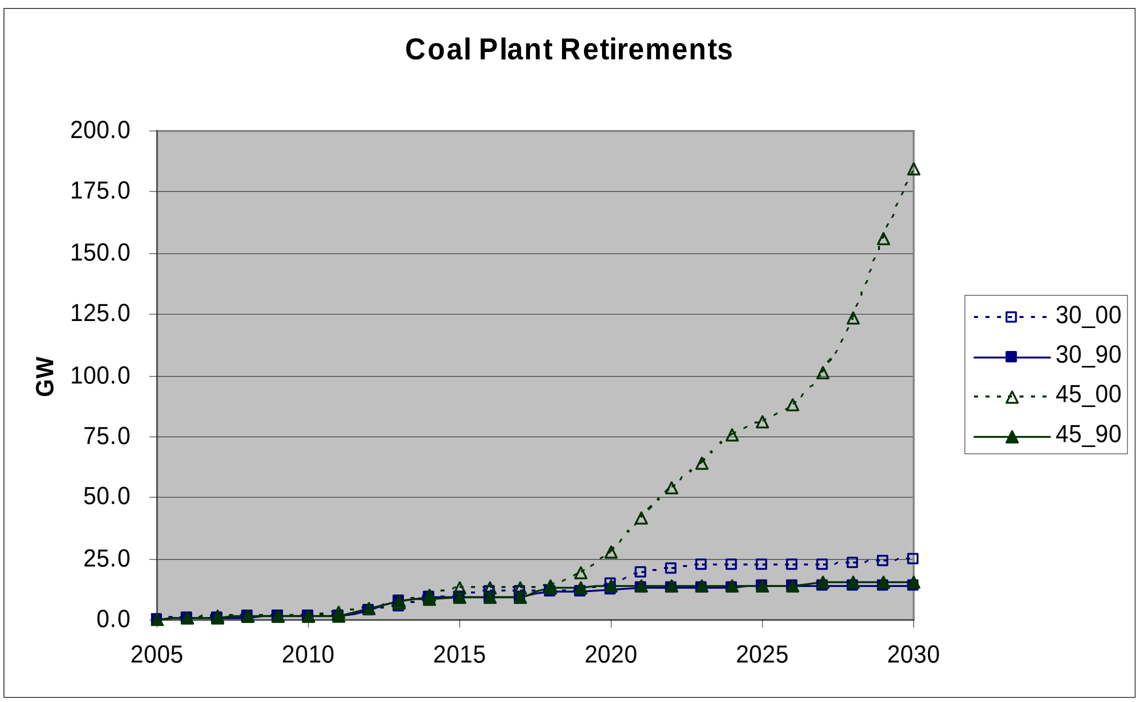

Figure A6: Coal Plant Retirements

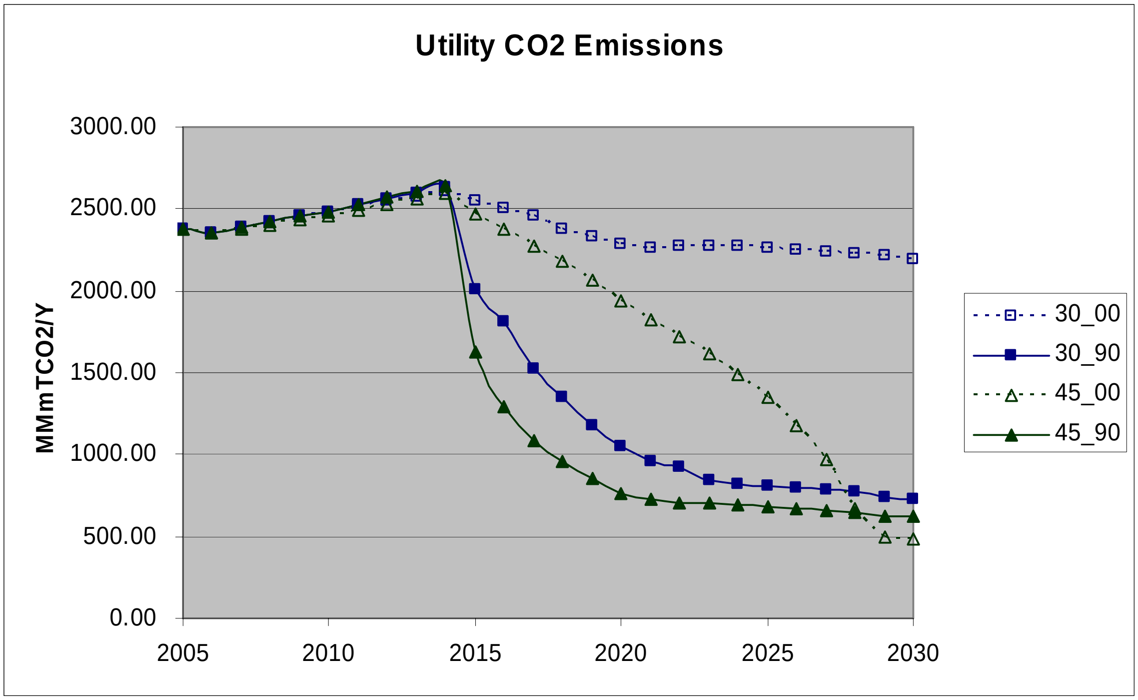

Figure A7: Utility CO_2 Emissions

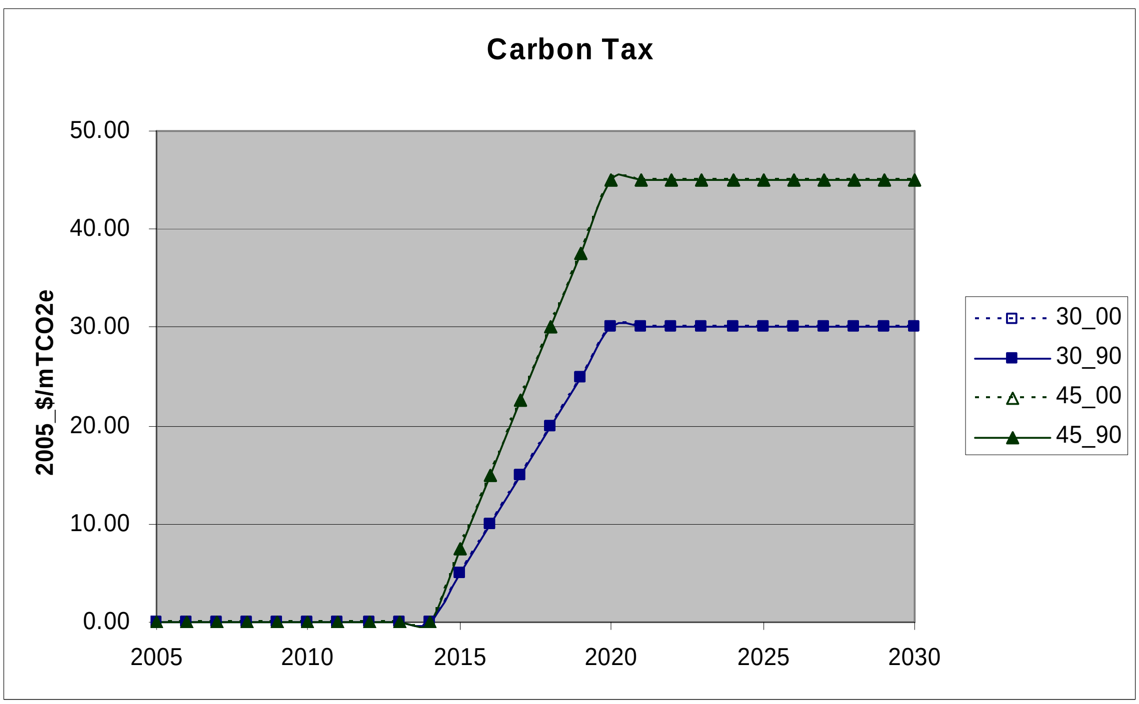

Figure A8: Carbon Tax