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How accounting for climate and health impacts of emissions could change the US energy system

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ABSTRACT

This study aims to determine how incorporating damages into energy costs would impact the US energy system. Damages from health impacting pollutants (NO_x, SO_2, particulate matter – PM, and volatile organic compounds – VOCs) as well as greenhouse gases (GHGs) are accounted for by applying emissions fees equal to estimated external damages associated with life-cycle emissions. We determine that in a least-cost framework, fees reduce emissions, including those not targeted by the fees. Emissions reductions are achieved through the use of control technologies, energy efficiency, and shifting of fuels and technologies used in energy conversion. The emissions targeted by fees decrease, and larger fees lead to larger reductions. Compared to the base case with no fees, in 2045, SO_2 emissions are reduced up to 70%, NO_x emissions up to 30%, $PM_{2.5}$ up to 45%, and CO_2 by as much as 36%. Emissions of some pollutants, particularly VOCs and methane, sometimes increase when fees are applied. The co-benefit of reduction in non-targeted pollutants is not always larger for larger fees. The degree of co-reduced emissions depends on treatment of life-cycle emissions and the technology pathway used to achieve emissions reductions, including the mix of efficiency, fuel switching, and emissions control technologies.

1. Introduction

Air pollution associated with energy production and use affects local air quality and global climate. Direct health impacts of air pollution include premature mortality (e.g., Krewski et al., 2009) and asthma exacerbation (e.g., Mar et al., 2004). Global climate change affects temperature and weather patterns (e.g., Kirtman et al., 2013), crop loss, and increased prevalence of certain diseases. These consequences are externalities – effects on the wellbeing of an unrelated group or individual outside the market mechanism that controls the price of energy. Damages are the monetary value of externalities. Health related damages from electricity generation in the US in 2005 have been estimated at over \$62 billion (NRC, 2010). Greenhouse gas (GHG) related damages from electricity generation in 2005 were \$118 billion, calculated using the 2010 Social Cost of Carbon with a 2.5% discount rate (IWG SCC, 2013).

Incorporating damages into energy costs would encourage practices that reduce the externalities. The most efficient policies are directed at the externality itself, such as a fee on emissions rather than on electricity. This allows the policy to most effectively reduce the externality instead of reducing the surrogate. By considering fees based on damages instead of an emission or technology goal, even if fees cause an increase in the price of electricity, the overall social cost related to electricity will decrease because external costs are lowered.

Guided by these general economic principles, previous studies have explored how energy systems might develop in response to application of fees to internalize external damages. Such studies (Klaassen and Riahi, 2007; Nguyen, 2008; Pietrapertosa et al., 2009; Rafaj and Kypreos, 2007) have used integrated energy system models to estimate changes to energy usage and production if fees are applied. They found that internalizing externalities might reduce energy consumption, change generation technologies, increase use of control technologies, and yield co-benefits through reduced emissions of un-taxed pollutants. Brown et al. (2013) focused on internalizing damage costs in the electric sector in the US but did not consider how the system would respond to fees implemented across all energy sectors. Jenkins (2014) discussed limitations of using fees to internalize externalities including political acceptability, overlap with existing policy, and household willingness to pay that might render fees non-optimal. On the other hand, Murray et al. (2015) examined the multi-decadal implications of

Abbreviations: AEO, Annual Energy Outlook; CAFE, Corporate Average Fuel Economy; CCS, Carbon Capture and Sequestration; DICE, Dynamic Integrated Climate-Economy model; EGU, Electric Generating Unit; EPA, Environmental Protection Agency; FGD, Flue Gas Desulphurization; GHG, Greenhouse Gas; HIP, Health Impacting Pollutant; LNB, Low NOx Burner; MACT, Maximum Achievable Control Technology; MARKAL, Market Allocation model; PIER, Public Interest Energy Research; PM, Particulate Matter; SCC, Social Cost of Carbon; SCR, Selective Catalytic Reduction; SNCR, Selective Non-Catalytic Reduction; VOC, Volatile Organic Compounds; VSL, Value of Statistical Life

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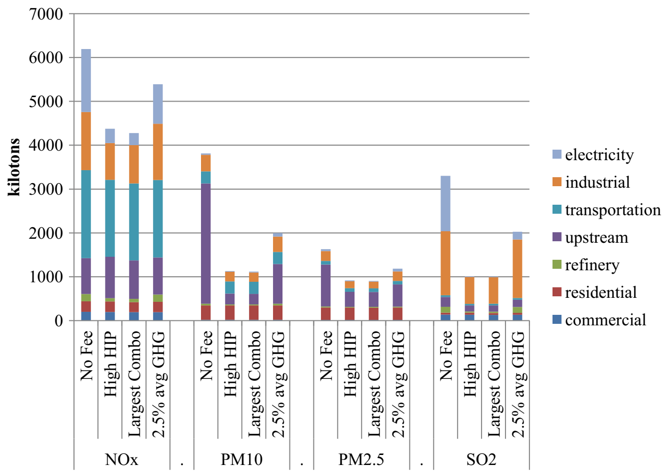

Fig. 2. HIP emissions in 2045 for selected cases. The results for all cases can be found in the Figs. A.8–A.11. The largest combined fee case includes high HIP fees and 2.5% average GHG fees.

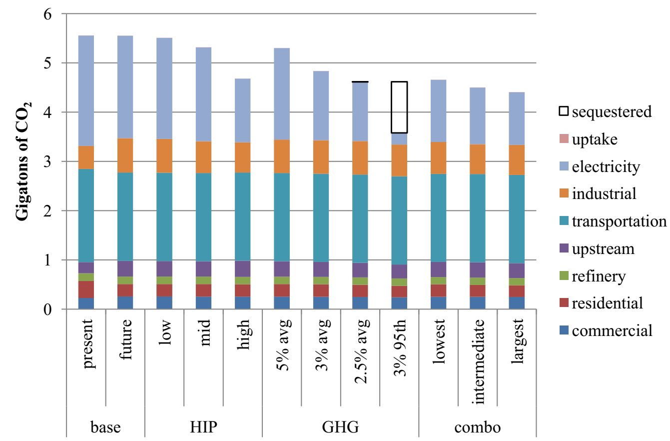

Fig. 3. CO_2 emissions by energy use sector in 2045 for various fee cases. The lowest combined (combo) fee case includes mid-range HIP fees and 3% average GHG fees, the intermediate fee case includes high HIP and 3% average GHG fees, and the largest fee case includes high HIP and 2.5% average GHG fees.

base case. Industrial sector NO_x emissions decrease 9–42% for HIP fee cases across fee levels and years. Industrial boiler NO_x controls are used with mid-range and high HIP fees. Transportation emissions decrease by at least 12% by 2040 in all cases with HIP fees and even earlier with high HIP fees.

GHG fees also cause HIP emissions reductions. Electric sector NO_x emissions decrease by up to 37% with 2.5% average GHG fees (Fig. 2). With 3% 95th percentile fees, the NO_x reduction is only a few percent (Fig. A.8), because the technologies used in this case are different from other GHG fee cases. Industrial sector NO_x emissions decrease 3–24% in GHG fee cases. With GHG fees, transportation NO_x is reduced 12% in 2040 and beyond, except for 5% average GHG fees in which only a 3% reduction is achieved (Fig. A.8).

Over half of PM emissions in both size fractions in the base case are from upstream processes. While control devices are used extensively in end use and electricity generation, controls for upstream processes are not modeled. Nevertheless, upstream PM responds to fees (Fig. 2 and A.10), due largely to reduced mining emissions from reduced coal use. With high HIP fees, upstream $PM_{2.5}$ emissions are up to 67% less and upstream PM_{10} up to 92% less than in the base case for the same year. $PM_{2.5}$ and PM_{10} emissions are also reduced with HIP fees in the industrial sector (about 30% with mid- or high HIP fees), from refineries (about 30% with all HIP fees), and from electricity generation (over 50% with high HIP fees). Fabric filters are applied in response to fees to reduce electric sector PM emissions. In all GHG fee cases, upstream $PM_{2.5}$ and PM_{10} emissions are always at least 58% less than the base case. Reductions in industrial PM with GHG fees are modest, except for the 3% 95th percentile GHG fee case, which after 2035 has up to 15% less $PM_{2.5}$ and 21% less PM_{10} than the no fee case. With GHG fees, PM from the electric sector actually increases (up to several times) due to the increased use of biomass co-firing. This impact could be mitigated with use of controls that are not currently represented in the MARKAL database.

SO_2 emissions are tied to coal use, so they are heavily affected by fuel choice, but also by control technologies. With high HIP fees, electric sector SO_2 emissions are reduced by at least 63% starting in 2015 and at least 98% in 2025 and beyond; mid-range HIP fee reductions are 76–81% after 2020 (Fig. 2 and A.9). With low HIP fees, electric sector SO_2 emissions are within 30% of the base case. FGD scrubbers are used to reduce SO_2 in all cases, but reduced coal use is also a large factor with mid or high HIP fees. Industrial SO_2 emissions are 35–62% less than the base case in different years with mid or high HIP fees, with SO_2 controls used for process heat and boiler emissions. GHG fees corresponding to the 2.5% average or 3% 95th percentile levels reduce electric sector SO_2 emissions by at least 83% after 2025. With GHG fees, industrial SO_2 emissions are 2–33% less than the base case.

VOC emissions do not typically decrease with fees, and may even increase because there are limited control technologies modeled to reduce these emissions and fees on VOCs are smaller than on other pollutants. Results for VOCs are discussed further in Appendix A.3.

CO_2 emissions are reduced in all fee cases, particularly the electric sector (see Fig. 3). With mid-range HIP fees, electric sector CO_2 emissions are 8–12% less, and with high fees 38–47% less across years. Industrial sector CO_2 emissions are reduced by 10% with mid-range HIP fees and up to 14% with high HIP fees. Electric sector emissions in 2045 are 9–13% lower than in the base case with 5% average GHG fees, 26–35% lower with 3% average GHG fees, 37–46% lower with 2.5% average fees, and 89% lower with 3% 95th percentile fees. CCS is used in the electric sector to reduce CO_2 emissions in the 2.5% average and 3% 95th percentile cases. Sequestered CO_2 is represented in Fig. 3 as an outlined box. Industrial CO_2 is reduced by 5% with 2.5% GHG fees in most years, and by up to 12% with 3% 95th percentile fees.

Methane emissions are almost entirely upstream (see Fig. A.12). Differences in methane emissions between cases are small and mostly related to changes in natural gas use, because control options are not modeled for upstream methane emissions. In the high HIP fee case, methane emissions are 6% higher than in the base case; with mid-range HIP fees, they are 2% higher than in the base case. They are 6% less than in the base case with 2.5% average GHG fees, and 14% less with 3.5% 95th percentile fees.

Combined fees reduce total emissions of a pollutant more than either set of fees alone while using fewer control technologies, although emissions from a particular sector may be increased slightly. With combined fees, industrial NO_x controls are used less because more fuel switching occurs that reduces controllable emissions. Industrial sector NO_x emissions are slightly higher in combined fee cases compared to HIP fee cases. After 2020, combined fees reduce electric sector NO_x by 60–83%, which is more than with HIP fees alone. The lowest combined fee case has larger reductions in SO_2 than either set of fees alone, with an 89–94% electric sector emission reduction. The intermediate and largest combined fee cases have similar reductions to the high HIP fee case. In the combined fee cases, industrial SO_2 controls are used less because more emissions are reduced through fuel switching. The PM in the combined fee cases behaves similarly to the HIP fee cases, except that the upstream PM in the lowest combined fee case is reduced by about 70% after 2025, much more than with the mid-range HIP fees.

near-term policies to reduce CO_2 emissions, including tradeable and non-tradeable emissions rate limits as well as modest emissions fees. They found non-tradeable rate limits had the most lasting effect, as they led to some coal plant retirements. Carbon fees had a more neutral effect on the future electricity system and corresponding policy options. While Brown et al. and Murray et al. focused on the electricity sector, applying fees more broadly could yield greater emissions reductions and benefits, or afford more cost effective emissions reductions. This will also ensure that reduced emissions in the electric sector are not outweighed by increased emissions elsewhere.

The dual impacts of air pollution on human health and climate, and differences between regulatory frameworks designed to address health impacting pollutants (HIP) versus GHGs, raises questions regarding how fees on emissions of one category may impact the other. Different pathways to specified emissions reductions can have different co-benefits or even regional disbenefits (Driscoll et al., 2015). Carbon policies that allow reductions from multiple sectors are estimated to achieve larger co-benefits and reduce the cost of compliance (Thompson et al., 2014; Saari et al., 2015). Studies examining how air quality and climate goals might be met symbiotically (Chen et al., 2013; Kleeman et al., 2013; Nam et al., 2013; Zapata and Muller, 2013) found that energy efficiency and fuel switching measures usually lead to co-benefits. Directly encouraging energy efficiency can also lead to emissions reductions (Wang and Brown, 2014; Melo and Jannuzzi, 2015), but can be difficult to model, particularly in the industrial sector (Kesicki and Yanagisawa, 2014). As a counterexample, however, Leinert et al. (2013) found that Ireland might emit excess NO_x when reducing GHG emissions due to shifting from gasoline to diesel vehicles.

In this paper, we evaluate how incorporating external costs into the cost of energy could change energy use and emissions in the US. Ranges of damage estimates from the literature are used to construct scenarios prescribing emission fees for GHGs and HIPs. A modified version of the EPA US 9 region MARKAL (MARKet ALlocation) model is used to evaluate resulting changes to the US energy system through 2055. Emissions reductions can be achieved through application of control technologies, changing fuels or conversion technologies, and improved efficiency. We compare emissions reductions with fees on HIPs, GHGs, and both simultaneously. We examine co-reductions and increases in non-targeted pollutants as well as reductions in targeted pollutants. Our fee structure and modeling system are specific to the energy system (from fuel extraction through processing, energy conversion, and end use); hence, we do not consider non-energy related emissions reduction pathways in sectors such as agriculture, waste disposal, or most industrial processes. Most anthropogenic emissions in the US are associated with energy production, conversion, or use including 83% of GHG emissions (US EPA and CCD, 2016), 95% of NO_x emissions, 60% of VOC emissions, 48% of primary $PM_{2.5}$ emissions, and 91% of SO_2 emissions (OAQPS, 2015); therefore, although we restrict our analysis to the energy sector, we capture the majority of anthropogenic emissions.

2. Methods

2.1. Health related damages

HIP emissions considered here are NO_x, $PM_{2.5}$, PM_{10}, SO_2 and VOCs. Hazardous air pollutants can also cause adverse health effects but are not considered here. Three sets of sector-specific, damage-based fees are considered (Table 1). All monetary values in the paper are for year 2005 USD. Damage values for pollutants should be location dependent because emissions that lead to pollutant concentrations near population centers will affect more people than those that generate rural pollution. Location-dependence is partly captured in this study by using different damage values for different sectors, e.g., with higher damage values for industrial and transportation emissions than for electric sector emissions.

Table 1
Health impacting pollutant damages used as fees. (All values in 2005 USD/t unless otherwise specified.) The [a] represents values that were taken from a different literature source than the rest of that set of fees, see sources in text. These fees are constant through time once they are applied.

$/ton	Sector	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC	Natural Gas Use M$/PJ
Low Sector Specific Fees	Electric	364	195	2261	1866	240	
	Industrial	547	378	4343	2274	436	
	Transportation	593	444	5147	2476	510	
	Upstream	501	339	3917	2205	395	
	Refinery	547	378	4343	2274	436	
	Residential						0.059[a]
	Commercial						0.025[a]
Mid Fees	All	1970	1115	21520	9750	1720[a]	
High Sector Specific Fees	Electric	4700	4110[a]	117100	31500	2330[a]	
	Industrial	5500	4110[a]	234300	35100	2330[a]	
	Transportation	6600	4110[a]	324400	17100	2330[a]	
	Upstream	5600	4110[a]	225267	27900	2330[a]	
	Refinery	5900	4110[a]	279300	59500	2330[a]	
	Residential	11700	4110[a]	324400	87400	2330[a]	
	Commercial						0.579[a]

[a] Marked values represent represents values taken from a different literature source than the rest of that set of fees, see sources in text.

We selected the fees used here to represent the range of values reported in recent literature. Low sector-specific fees are derived from Muller et al. (2011). Mid-range fees are from NRC (2010), except the mid-range VOC fee is based on the geometric mean of VOC damages from Muller and Mendelsohn (2007) and Fann et al. (2009). High fees are based on damages from Fann et al. (2012) except that VOC damages are from Fann et al. (2009). PM_{10} values in the high fee case are based on NRC (2010) values multiplied by a factor representing the average increase of Fann et al. (2012) over NRC (2010). These adjustments allow us to apply fees to the same set of pollutants in all cases. Damages for the residential and commercial sectors are sometimes only applied as fees to natural gas used, corresponding to the way damages have been reported for these sectors. Most energy use in these sectors is in the form of electricity or natural gas, so we assume that these estimates capture most of the damages. The damages in Table 1 in the natural gas use column are derived from NRC (2010) by multiplying by a ratio as described above for PM_{10}.

Sources of discrepancies in reported damage estimates include whether age is taken into account when applying the Value of Statistical Life (VSL) to pollution-caused mortalities. Using a uniform VSL can produce 50% higher marginal damages than differentiating by age (Muller et al., 2011). Only Muller et al. (2011) differentiate VSL based on age. Which emissions sources are considered can also cause differences in estimated damages. Muller et al. (2011) and Fann et al. (2012) consider a wide range of sources while NRC (2010) focuses on EGUs combusting coal and natural gas. There are also variations in the areas considered for population exposure. Since mortality from $PM_{2.5}$ is a significant component of damage estimates, the choice of corresponding concentration-response functions is also important. NRC (2010) and Muller et al. (2011) used results from Pope et al. (2002) and Woodruff et al. (2006) to relate $PM_{2.5}$ exposure to mortality; Fann et al. (2012) used health impact functions from Krewski et al. (2009). Fraas and Lutter (2013) found that uncertainty in the concentration-response functions may be larger than that encompassed by the range of studies considered here. Buonocore et al. (2014) showed that variability of damage estimates between individual facilities may be important for evaluating the benefits of alternative energy technologies (e.g., Siler-Evans et al. (2013)). Although we do not have the ability to incorporate this level of variability into our modeling framework, we partially account for this

Table 2
The cost of the fees for lifecycle emissions translated to 2005 USD/kWh for two electricity generating technologies in 2045.

Taxed pollutant	Level	Fees for coal ($/kWh)	Fees for NGCC ($/kWh)
GHG	5% avg	0.02	0.01
GHG	3% avg	0.07	0.03
GHG	2.5% avg	0.09	0.04
GHG	3% 95th	0.21	0.08
HIP	Low	0.01	0

make coal the more expensive fuel to use to generate electricity. Even accounting for their lower efficiency, the fuel and facility costs for existing coal plants are lower than for new natural gas plants. However, adding high fees on emissions shifts the costs in favor of natural gas generation. The importance of the fees is illustrated in Table 2, which shows the additional cost due to fees for an existing coal fired power plant and a new NGCC plant, both operating in 2045, assuming no additional control technologies.

3.4. Transportation, Residential and Commercial Technologies

As modeled here, the transportation, residential, and commercial sectors are relatively unresponsive to fees. In the commercial sector, up to 8% less natural gas is used with very high GHG fees than in the No Fee case, due to use of more efficient end-use devices. In the residential sector, less electricity is used with GHG fees, again due to the use of more efficient devices. With very high GHG fees the use of electricity for space heating is closer to that in the HIP fee cases, offsetting the reduction in natural gas use. With GHG fees there is about 2% more biodiesel used in transportation replacing traditional diesel, and with all fees more advanced diesel shipping is used with hybrid electric capabilities.

4. Discussion

Although fees vary by sector, the sectors with the most emissions reductions tend to be driven more by availability and price of technologies than the value of the damages across sectors. On a per ton basis, the highest fees are generally in the transportation and residential sectors, two sectors that show very little response to fees. In contrast, fees are typically lowest for the electric sector, which has the largest emissions reductions. This sector has a wealth of technology options defined in the model, many of which are less expensive than similar options in other sectors due to economies of scale. We find the fuels and technologies used to generate electricity show larger changes in response to HIP fees in this study than we saw in our previous work (Brown et al., 2013). Some of the difference is likely due to reductions in the assumed cost of newer technologies with the updated MARKAL database compared to previous estimates. In particular, we used lower natural gas supply costs and a lower investment cost and hurdle rate for new natural gas EGUs than used in Brown et al. (2013). The industrial and refinery sectors have control costs that are higher than the electric sector, but lower than other sectors. Correspondingly, they show intermediate responses to fees.

Fig. 5 displays the fees collected in each case, corresponding to residual emissions that cannot be cost-effectively avoided given the options included in the model. With little reduction in emissions when fees are applied, the transportation sector accounts for at least 30% of fees collected in GHG fee cases. The residential sector contributes about 20% of the fees collected in the HIP fee cases. High hurdle rates for new technology in the transportation, residential, and commercial sectors makes it less likely that more efficient or lower emissions options will be selected. High discount rates reflect the hesitance or inability of individual or smaller scale consumers to spend on large upfront investments and less familiar technologies but are sources of uncertainty in the model (e.g., US EPA, 2013). Advances in technology or new financing options could reduce these barriers; for instance novel financing has increased residential PV installations (Coughlin and Cory, 2009). This is an example where the model might not fully describe the real world response to the fees, if the price or options of technologies in sectors with high fees were to change in response to the policy.

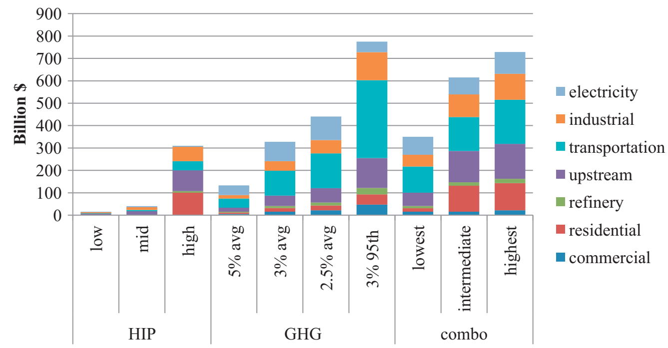

Fig. 5. Fees collected by sector in each case in 2045 in year 2005 USD.

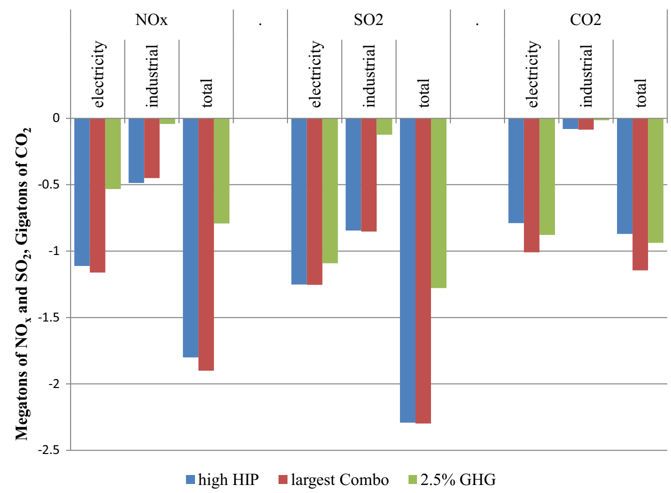

Fig. 6. Emissions reductions compared to the No Fee case in 2045 in the electric sector, industrial sector, and across all sectors.

The co-reduced emissions with different fee cases are highlighted in Fig. 6. Total emissions reductions in combined fee cases are larger than for the component fee cases. The largest combined fee case (in red) includes both high HIP fees and 2.5% GHG fees. The SO_2 reductions in the combined fee case are nearly identical to those in the HIP fee case and NO_x reductions are only 5% more with combined fees than with HIP fees alone. CO_2 emissions are reduced an additional 22% with combined fees compared to GHG fees. Thus while combined fees lead to additional reductions for both categories of pollutants, the largest change is for GHG emissions. The co-benefit of individual fees is also of interest. While the co-benefits of HIP fees are total CO_2 reductions that are 93% of those achieved with GHG fees, total NO_x and SO_2 emissions reductions from GHG fees are only 44% and 56%, respectively, of those achieved by HIP fees. Although this finding is sensitive to which two sets of fees are compared, the high HIP fees lead to similar or larger reductions in CO_2 emissions than most GHG fee cases, while NO_x and SO_2 reductions with any set of GHG fees examined here are smaller than those in all but the low HIP fee case.

Although emissions reductions achieved with combined fees are generally greater than or equal to those of the constituent single fee

The combined fee cases have slightly larger reductions of CO_2 than either set of fees alone. CCS is not used in any combined fee cases. With combined fees methane emissions are reduced up to 5%, which is less than with GHG fees alone, but avoids the increase seen with HIP fees.

3.2. Industrial sector technologies

In all cases, natural gas and biomass-fired boilers are added in the industrial sector to keep up with increased demand over time. Electricity, LPG, and natural gas use increase to meet additional process heat demand. Increased natural gas, coal, oil, and electricity also help meet increased demand for other industrial energy needs, and oil use increases as a chemical feedstock.

The options for reducing emissions in the industrial sector in MARKAL remain limited, but the additions we made to the model allow for some responses to fees, particularly with boiler and process heat energy uses. Additionally, the “other” energy use category has some flexibility; as HIP fees increase, the use of petroleum coke and coal decreases and the use of electricity and oil increases to maintain the same level of energy provided, see Fig. A.16.

For process heat (Fig. A.13), the main change with fees is for cases with mid or high HIP fees, where coal use is significantly reduced (at most 16% of the base use with high HIP fees or 63% with mid-range fees) and consequently electricity use is increased. The same effect is seen to a much smaller degree for the 3% 95th percentile GHG fee case (63–94% as much coal is used compared to the base case). The case with the lowest combined fees uses slightly more coal than with mid-range HIP fees alone, while both combined fee cases with high HIP fees use less coal than with high HIP fees alone. Flat plate solar heat is used to the maximum extent allowed by the constraints in all cases, including the base case. Concentrated solar heat is used to some extent in all cases, with its use increasing with high HIP fees or any GHG fees. Due to constraints, this represents a small fraction of overall energy use. In cases with more concentrated solar, less LPG is used.

Boilers show the largest share of technology changes in the industrial sector in response to fees. As with process heat, coal use decreases with mid- or high HIP fees and 3% 95th percentile GHG fees. Natural gas use increases with all fees, but is lower for the 3% 95th percentile GHG fee case than the 2.5% average case. Efficient natural gas boilers are used most in the high HIP and 3% 95th percentile GHG fee cases. Efficient LPG boilers are used in the base case and the low and mid HIP fee cases through 2040, after which their use trails off. LPG boilers are used less and efficient LPG boilers are not used at all with high HIP fees. Boiler efficiency retrofits for LPG are used for just over half of the LPG boilers in all GHG fee cases. Efficiency retrofits for coal boilers are used in low and mid HIP fee cases, for less than 10% of coal boilers. Up to 9% of the coal boilers are upgraded in the mid-range HIP case, so this case is building new, more efficient coal fired boilers as well as improving existing ones. New upgraded coal boilers are also used in all GHG fee cases, but always at less than 10% of all coal boilers. The use of boilers increases with GHG fees, but the use of fuels for unspecified industrial needs decreases in these cases so this is not an inefficiency, but a shift in energy use that is not apparent from the subset of results presented here. An additional (Fig. A.15) and more detailed discussion of industrial sector control technologies can be found in Appendix A.3.2.

3.3. Electric sector technologies

Electricity generation and use increases over time in all cases. In the No Fee case most of the increase is met through an increase in generation with natural gas combined cycle (NGCC) technology. Wind generation increases sharply through 2035 although it remains small in comparison to natural gas. Solar, albeit a small percentage of generation, also increases throughout the time period. The investment cost of wind and solar is projected to come down over time as is the investment cost for the most efficient NGCC plants. Hydropower and nuclear generation remain quite constant across time and cases. High hurdle rates are used for nuclear power to represent regulatory and other difficulties of constructing these new facilities combined with their large upfront costs. Investment in new hydroelectric capacity is not allowed in the model due to the difficulty of siting new facilities.

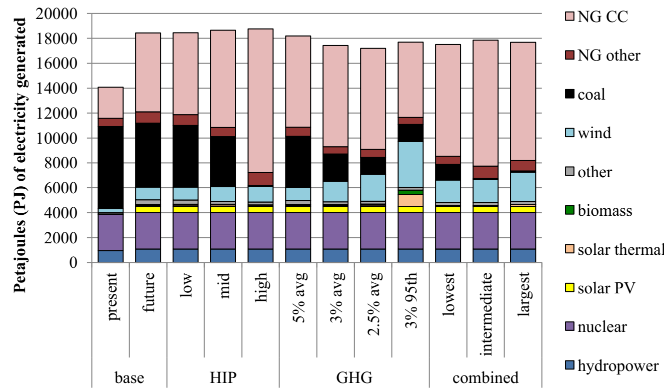

Fig. 4. Fuels and technologies used to generate electricity in 2045 for all fee cases and in 2010 and 2045 for the no fee case. The "other" category includes oil, geothermal, and waste to energy. The lowest combined fee case includes mid-range HIP fees and 3% average GHG fees, the intermediate case includes high HIP and 3% average GHG fees, and the largest case includes high HIP and 2.5% average GHG fees.

Electricity generation from coal and natural gas show the largest changes with fees (Fig. 4). Compared to the No Fee case, mid-range HIP fees reduce electricity generated from coal by 22% in 2045; high HIP fees reduce it by 98%. Much of this coal is displaced by NGCC. Coal use for electricity generation is reduced by 57% with 3% average GHG fees and by 73% with 2.5% average GHG fees. In the GHG fee cases, more renewable technologies are used, particularly wind, which is used approximately twice as much in the 2.5% GHG fee case as in the No Fee case.

The electricity mix in the case with 3% 95th percentile GHG fees differs from that in other cases, with reduced use of both coal and natural gas. Although natural gas has lower carbon intensity than coal, CO_2 and methane are still released. With 3% 95th percentile GHG fees, three and a half times more electricity is generated from wind in 2045 compared to the base case, and solar thermal use is up to 10 times greater than in other cases. Solar thermal use increases more than PV, which has a lower capital cost, because solar thermal has a higher capacity factor due to built-in thermal energy storage. Biomass co-fired with coal is also much higher in this case than others, up to 33 times more than in the base case, although this falls off in later years as coal use decreases. This shift away from natural gas and towards a larger increase in renewables with large fees shows that the changes do not scale linearly with fees, as fees beyond a certain level lead to responses that are quite different from those to lower fees.

In the electric sector, controls were applied in response to fees. Fabric filters were applied to reduce PM emissions. FGD (Flue Gas Desulfurization) scrubbers are used to remove SO_2. As the fees on HIP increase, fewer emissions are removed through control technologies, because they are only available for generation from coal, which decreases as fees increase. One exception to this trend is that SCR is used more in the mid-range HIP fee case than the low fee case. The low fee case uses more of the less efficient SNCR technology. Also, the combined fee cases use fewer controls than HIP fee only cases for the same reason.

The emissions fees are altering the economics of energy use in a complex system of energy prices. Natural gas prices are higher in the case with high HIP fees than in the other cases, due to increased use of natural gas and correspondingly higher costs on the supply curve. Because coal has much higher emissions than natural gas, high fees can by using sector specific damages and a multi-region model.

2.2. GHG related damages

Greenhouse gas damages used in this study are from the Social Cost of Carbon (SCC) estimates developed for use in regulatory impact analysis by the US government (IWG SCC, 2013). The SCC documentation recommends considering the full range of values they report given their numerous associated uncertainties. We have considered all four sets of values, which increase with time and are reported in the Appendix (Table A.1). Fees are applied to CO_2 and CH_4. Values are adjusted for CH_4 using a 100 year global warming potential of 28 (Myhre et al., 2013). Three sets of fees are determined by averaging results of several models considering different discount rates: 5%, 3% and 2.5%. The fourth set represents the 95th percentile of the ensemble of estimates for the 3% discount rate.

Some studies found GHG damage estimates larger than those used here. Moore and Diaz (2015) described how SCC may be underestimated because effects are compounded over time as GDP is reduced due to climate impacts. When Dietz and Stern (2015) incorporated endogenous growth into the DICE model, allowed for damages to increase rapidly with respect to temperature, and explored the climatic response to GHG emissions, they found the range of damages exceeds those used here. Lontzek et al. (2015) created a stochastic version of DICE and found that carbon costs were higher than when projected deterministically. Also, Howard (2014) reported that the SCC is probably biased low because some impacts are not included. NRC (2010) found that most variation in marginal damage estimates derives from differences in assumptions of discount rate and the magnitude of damages from climate change, especially whether unlikely but catastrophic effects were considered.

2.3. MARKAL model

We use the MARKAL energy system model to compare the fee scenarios (Brown et al., 2013; ETSAP, 1993; Loughlin et al., 2011; Loulou et al., 2004; US EPA, 2013). MARKAL uses linear optimization to determine the lowest cost set of technologies required to meet specified end-use energy demand and constraints such as emissions regulations. All end use demands must be satisfied, through either generation or conservation technologies (Loulou et al., 2004). MARKAL considers the economic advantages of different technologies. Incorporating external damages as fees ensures that environmental costs are also considered.

We use a modified form of the EPA US 9 region 2014 v 1.1 database (US EPA, 2013). The database represents the US energy system for the years 2005–2055 in 5 year increments with a system-wide 5% discount rate, based on the "business as usual" (BAU) case in the 2014 Annual Energy Outlook (AEO) (US EIA, 2014). We used the most recent MARKAL database available, although AEO 2016 (Energy Information Administration, 2016) has since been released. The oil prices in AEO 2016 are lower than those in AEO 2014 and natural gas price projections are higher in the more recent version, but both sets of projections are within the range of uncertainty probed by AEO sensitivity cases. The scope of the database extends from resource extraction through refinery and electricity sectors that convert energy to end-use demand in transportation, residential, commercial, and industrial sectors. The database includes projected demand for energy services as well as the existing technologies in each of the nine US census regions. Demand is specified in terms of heat, lighting, and other end use services instead of energy required so that efficiency options are available. The projected demand changes over time based on AEO projections.

The database also defines technologies that are available to install, including both traditional and advanced options. All technologies are defined by capacity, efficiency, cost, and emissions rate. Some technologies also have defined hurdle rates (typically 5–20%), which are elevated discount rates reflecting financial, behavioral, or non-economic barriers to new technology investments. The database includes investment costs, fuel costs, and operation and maintenance costs. Costs change with time, especially for newer technologies for which learning leads to cost reductions. Energy sources include waste, solar, wind, natural gas, coal, geothermal, hydropower, biomass, nuclear, and oil, with supply curves provided for natural gas, coal, biomass, and oil. Resources and energy are traded between regions over defined, extendable pathways such as transmission lines. Control technologies are also available in the model, including carbon capture and storage (CCS), flue gas desulfurization (FGD), and a variety of PM and NO_x removal technologies.

The database includes existing regulations. Electric sector SO_2 and NO_x emissions are constrained to comply with the Clean Air Interstate Rule (CAIR) (since replaced by the Cross State Air Pollution Rule, which is similar at the level of resolution represented in the database). Mercury Air Toxics Rule and other existing Clean Air Act-based regulations are represented, along with state renewable fuel standards in place as of 2013. For transportation, compliance with Tier III emissions regulations and Corporate Average Fuel Economy (CAFE) standards of 54.5 mpg (23.2 km/l) by 2025 is required. In the industrial sector, the Industrial, Commercial, Institutional (ICI) boiler Maximum Achievable Control Technology (MACT) rule is represented. New and proposed policies targeting methane emissions from oil and gas extraction (BLM, 2016; US EPA, 2016) are not represented in the database, nor are recent extensions to renewable energy tax credits. The Clean Power Plan is not included in the database, due to its uncertain status, but we compare results for the electricity sector with emissions reductions expected from the Clean Power Plan.

MARKAL's flexibility and completeness make it well suited for this study. However, while MARKAL can determine types of responses to fees that might be likely, including whether and how emissions are reduced and potential for co-benefits or dis-benefits, the results should not be interpreted as forecasts. Although technological learning is incorporated into future cost and performance projections, MARKAL is not designed to determine how novel or disruptive technologies might contribute to the energy system; emissions fees could spur innovation in technologies that are not represented in the model. Furthermore, certain sectors may not have enough technologies modeled to respond to fees even if such options could become available in the real world. This could occur if newer financing or technology options gain traction in sectors such as residential, commercial, and transportation. MARKAL provides a picture of possible responses to emissions fees and shows that emissions reductions to a certain level are possible, but results do not show the only possible pathway to emissions reductions.

2.4. MARKAL database changes

2.4.1. Emissions

Starting from the EPA US 9 region database described above, we modify the database to aid analysis of possible methods of reducing emissions. A comparison of the EPA base case with the modified base case is presented in Appendix A.2. Additional emissions tracking parameters are added to analyze emissions from each sector. We improve treatment of upstream emissions by adding previously uncounted emissions, including CO_2 uptake for biomass production, and adding the ability to track upstream emissions separately (Table A.2).

2.4.2. Industrial sector changes

Most of our changes to the EPA database are for the industrial sector, because many technologies that could be used to reduce emissions in this sector are not included in the original EPA database. That database has different fuel options available to meet industrial heat and energy demands, but no emissions control technologies for the industrial sector and efficiency improvements only for natural gas

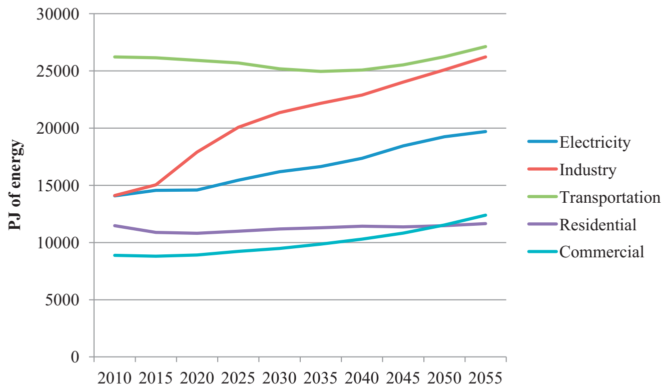

Fig. 1. Total fuel used or electricity produced by each sector across time in the base case as a proxy for increase in demand for energy services. Roadway vehicle miles traveled is expected to increase 43% in all MARKAL cases from 2015 to 2055, but transportation fuel use is mitigated by increased efficiency.

boilers. It is not possible to represent the full range of methods available to reduce emissions in this highly varied sector, as some options are only available for small subsectors of industrial energy use.

For this study, we expand the technologies modeled to create a representative picture of the available responses (i.e., fuel switching, efficiency improvements and control technologies), which allows us to better analyze which emissions reduction techniques might be important. We add the option of improving boiler efficiency by one percentage point at an associated capital cost of 1.082 million USD per PJ (US EPA, 2010) for boilers. Standard and efficient options are available for all boilers, but the EPA database defines both options for natural gas. Control technologies are added to boiler and process heat energy use based on CoST modeling (Misenheimer et al., 2010).[1] For boilers, two levels of NO_x controls and one level of SO_2 control are added. For process heat, options are added to control SO_2, PM and NO_x. All controls become available in 2015 with a 40-year lifetime. Penetration of controls is constrained to at most 80% of the possible level. For boilers subject to boiler MACT regulations or for which other controls are assumed in the EPA database, additional controls are not modeled on affected pollutants, with the exception that in some cases Low NO_x Burners (LNB) exist for boilers but selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) controls could still be applied. No PM controls are added to boilers because they have already been feasibly used to comply with the MACT regulations. No VOC controls are added because controllable sources either are not part of the energy system or controllable processes not explicitly defined in MARKAL.

For refineries, new control options are added using performance and cost estimates from the Mid-Atlantic Regional Air Management Association (MARAMA, 2007). A wet scrubber provides combined control of SO_2 and PM; two NO_x reduction options are added, and advanced leak detection and repair techniques are represented to reduce VOC emissions.

Although the US currently does not utilize much solar heat in the industrial sector, other countries have found solar energy to be a cost efficient option (Islam et al., 2013). We define a flat plate solar technology available only for the food sector based on temperature requirements. We add the option of using parabolic trough technology for several industrial subsectors. Hurdle rates for solar heat were set to 20%.

We also added CCS options for cement process heat. CCS is included in the original database only for electricity generation. Emissions for cement process heat are also altered to account for the large portion of CO_2 that occurs due to calcination in addition to emissions from fuel combustion, because these emissions can alter the economics of using the controls.

2.4.3. Other changes

Constraints are added to retire coal fired power plants after operation for about 75 years. The CO_2 removal efficiency is lowered for biomass Integrated Gasification Combined Cycle with CCS based on the kg C/kWh rate given in Rhodes and Keith (2005). The costs for solar photovoltaic electricity are lowered based on an NREL report (Black and Veatch, 2012), and the cost of new electricity transmission is increased (NREL, 2012). Our updates are similar to those made in AEO 2016 (Energy Information Administration, 2016) in assuming reduced costs for solar energy compared to the original EPA database.

2.5. Scenario description

We run ten fee cases and a no fee (base) case. Three HIP fee cases and four GHG fee cases are run using the fees in Table 1 and Table A.1. Three combined fee cases are run, one with mid-range HIP fees and 3% average GHG fees (lowest combined fee case), one with high HIP fees and 3% average GHG fees (intermediate combined fee case), and one with high HIP fees and 2.5% average GHG fees (largest combined fee case). Fees start in 2015 in all cases. In some figures, base case results are presented for 2010 to show the pre-fee level and 2045 to compare to the other results.

2.6. Current energy system and business as usual demand for energy

The US currently uses mostly coal and natural gas to generate electricity. While many technologies are in place to reduce HIP emissions, more stringent control technologies are available. The industrial sector uses mostly natural gas with some actions taken to reduce emissions, but again further reductions are possible. The transportation sector uses mostly gasoline and diesel fuel with extensive emissions controls. Further emissions reductions could be achieved using advanced technologies, including fuel cell and electric vehicles. There is increasing demand for energy services in all sectors as population is expected to increase. Reflecting this increase, Fig. 1 shows energy use or electricity production in the base case. For sectors like transportation, increasing demand for energy services (e.g., vehicle miles traveled) is offset over time by improved energy efficiency.

3. Results

3.1. Emissions

Despite increased demand, emissions of HIPs decrease over time due to existing control requirements for transportation and electric sector emissions (see Figs. A.3–A.6). NO_x emissions reduce 39% from 2010 levels by 2045 in the base case. This is achieved by a 64% reduction in transportation NO_x and a 30% reduction in electric sector NO_x, despite a 33% increase in industrial NO_x. $PM_{2.5}$ emissions are 21% lower in 2045 in spite of a 54% increase in industrial emissions, due to a 63% and 70% reduction in transportation and electric sector emissions, respectively. Base case SO_2 emissions in 2045 are 52% less than in 2010. Although industrial emissions increase 22% in this time period, electric sector emissions decrease 75%. VOC emissions are 31% lower in 2045, mostly due to a 74% decrease in transportation VOC emissions.

When considering either HIP or GHG fee-driven scenarios, we find NO_x emissions reductions from fees (Fig. 2 and A.8) are greatest in the electric sector, followed by the industrial sector. Electric sector emissions decrease by a few percent with low HIP fees, 11–33% with mid-range fees, and up to 82% with high HIP fees. With mid-range or high HIP fees, refinery NO_x emissions decrease by 56% compared to the

[1] CoST modeling performed by Julia Gamas at the EPA.

cases, the methods of reducing emissions sometimes shift. In combined fee cases, less use is made of emissions control technologies and more reductions are achieved through efficiency or fuel switching, which typically reduce all emissions instead of a subset. For instance, fewer industrial controls are used in the combined fee cases, but more electricity is generated using wind so that total HIP emissions are reduced. The involvement of two different sectors in this change between the combined and HIP fee cases shows that there is interplay in where emissions reductions occur, and that including more sectors leads to more options for emissions reduction.

It is of interest to compare the results from this study to expectations for the US EPA's Clean Power Plan (CPP), which aims to reduce CO_2 emissions from electricity generation by 32% from 2005 levels by 2030 (US EPA, 2015). Our study suggests a similar reduction could be achieved with a fee level between the 5% average and 3% average GHG fees, which respectively reduce CO_2 from the electric sector by 23% and 42% from 2005 levels in 2030. Similar CO_2 reductions are also reached in the mid and high HIP fee cases. The SO_2 emissions from the electric sector are lower than those estimated to result from the CPP in all the fee cases considered here except those with low HIP fees and 5% GHG fees. However, only the mid- and high- HIP fee cases achieve lower electric sector NO_x emissions than expected as CPP co-benefits.

While this analysis advances understanding of cross-sectoral implications of accounting for external costs in the energy system, uncertainties in the analysis should be recognized in considering the results. There are uncertainties in the damage estimates on which the fees are based; we thus consider a range of fees but recognize that to implement a damage-based fee careful consideration should be paid to what fee level is chosen. Actual damages vary with location of the emissions, and will also change over time with changes in population demographics, baseline health status, and other factors. Estimates of marginal damages should be revisited as population and emissions sources change. The marginal damage literature continues to expand, including improved spatial specificity (Heo et al., 2016) and values analogous to SCC for a broader range of pollutants (Shindell, 2015; IWG SCGHG, 2016). Knowledge of the relationship between air quality and health is also expanding, and future damage estimates should account for evolving research on air pollution exposure such as the impact of $PM_{2.5}$ on preterm birth (Sun et al., 2015), potential links of $PM_{2.5}$ and NO_x with diabetes (Wolf et al., 2016), and revised estimates of O_3 related mortality (Turner et al., 2016). Although we have modified the MARKAL database to better represent the suite of fuel and technology options available, there are still limitations in that representation. There are inherent uncertainties in projecting demand, technologies, and costs for the future, as well as modeling an energy system given coarse temporal resolution. For future modeling applications, the MARKAL database should incorporate the changes made here as well as additional information about newer technologies as it becomes available. Additionally, the representation of the industrial sector can be further refined and options for reducing upstream emissions can be modeled. Improved spatial resolution in both fees and MARKAL would be possible and could generate more informative results as well.

5. Conclusions and policy implications

In this study we model the effect of damage-based fees in the US energy system with the objective of accounting for health and climate costs in planning the least-cost means to provide energy. Fees are applied to emissions of health impacting pollutants (HIPs) and GHGs both separately and in combination. All fee cases lead to emissions reductions, but the degree of reduction and the technologies used to achieve those reductions differs for different fees studied. HIP emissions decrease over time in all cases, including the base case, and decrease as HIP fees increase. The decrease in emissions over time in the base case is due to existing policies to reduce emissions. Emissions control technologies are important in responding to HIP fees. Energy efficiency tends to be more important for cases with GHG fees. Less total electricity is produced in GHG fee cases than other cases, with most of the reduction in demand coming from the industrial sector followed by the residential sector.

Although the 3% 95th percentile GHG fees lead to larger reductions in targeted emissions than the next largest fees (2.5%), there are more HIP emissions in the former case (Figs. A.8–A.11). This is due to a shift away from natural gas and an increase in biomass combustion with the highest GHG fees, demonstrating that the response to different levels of fees is more complicated than a simple scaling. The use of CCS also decreases co-benefits because this technology greatly reduces overall efficiency of the electricity generation system, leading to an increase in pollutants other than CO_2. This reversal of co-benefits for the highest GHG fees shows that it is important to consider all effects of interest for each policy proposal. The reduced use of natural gas in this case shows that upstream emissions should not be neglected. While upstream emissions can be harder to calculate and measure, applying a fee that captures damages related to upstream emissions should be considered for fuel purchases or technology investments.

Emissions reductions in combined fee cases are achieved using different strategies than those used in corresponding GHG and HIP fee cases. Coordinated GHG and HIP fee policies should be considered to optimize their combined effect. On a percentage basis, the HIP emissions reduction co-benefits with GHG fees are much smaller than the GHG emissions reduction co-benefits with HIP fees. This suggests that GHG emissions need to be explicitly targeted to achieve reductions, but as discussed in Section 2.2 it is possible that the range of GHG fees used here underestimates damages.

Emissions are reduced most from the electricity sector, despite the low per ton damages compared to other sectors. This supports initial regulatory action directed at the electric sector, and the large modeled response in the industrial sector indicates that might be a target for future emissions policy. It may also be that fees are not the ideal policy mechanism for targeting other sectors. For some sectors, high discount rates on investment in new technologies mean that a fee targeting emissions may not be large enough to overcome investment barriers required to respond to the fees. Alternative policy mechanisms employing fees or subsidies on purchase price of vehicles or residential and commercial technologies based on projected lifetime emissions should be considered for the transportation, residential, and commercial sectors.

Damage based emissions fees lead to reduced emissions, but the degree of reduction and pollutants reduced depends on the specific fees. Targeting all pollutants of interest will ensure those pollutants are reduced, whereas optimal emissions levels may not be reached if policies rely on co-benefits to produce emissions reductions for some species. In addition to analyzing the effect of fees on the energy system, the results of these model cases also point to cost-effective sources of future emissions reductions. These opportunities include potential emissions reductions in the industrial sector and upstream emissions from fuel extraction and processing. Finding emission reductions with damage-based fees shows that there are additional measures that can be taken with benefits that outweigh the additional cost of new technologies.

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Appendix A. Supplementary material

Supplementary data associated with this article can be found in the online version at doi:10.1016/j.enpol.2016.12.052.

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