KENTUCKY PUBLIC SERVICE COMMISSION
Docket Nos. 2011-00161 and 2011-00162

Environmental Intervenors' Responses and Supporting Attachments to September 30, 2011 Data Requests by Louisville Gas and Electric Company and Kentucky Utilities Company

Enclosed: Attachments in Response to Question 16
(Binder 2 of 2 for Question 16)

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(1st of 2 Binders for Question 16)

ENERGY TECHNOLOGY INNOVATION POLICY

A joint project of the Science, Technology and Public Policy Program and the Environment and Natural Resources Program
Belfer Center for Science and International Affairs

HARVARD Kennedy School
JOHN F. KENNEDY SCHOOL OF GOVERNMENT

Realistic Costs of Carbon Capture

MOHAMMED AL-JUAIED
ADAM WHITMORE

Discussion Paper 2009-08
July 2009

energytechnologypolicy.org

Realistic Costs of Carbon Capture

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ENERGY TECHNOLOGY INNOVATION POLICY (ETIP)

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ETIP researchers seek to identify and promote strategies that these countries can pursue, separately and collaboratively, for accelerating the development and deployment of advanced energy options that can reduce conventional air pollution, minimize future greenhouse-gas emissions, reduce dependence on oil, facilitate poverty alleviation, and promote economic development. ETIP's focus on three crucial countries rather than only one not only multiplies directly our leverage on the world scale and facilitates the pursuit of cooperative efforts, but also allows for the development of new insights from comparisons and contrasts among conditions and strategies in the three cases.

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ABSTRACT

There is a growing interest in carbon capture and storage (CCS) as a means of reducing carbon dioxide (CO_2) emissions. However, there are substantial uncertainties about the costs of CCS. Costs for pre-combustion capture with compression (i.e. excluding costs of transport and storage and any revenue from EOR associated with storage) are examined here for First-of-a-Kind (FOAK)[3] plant and for more mature technologies (Nth-of-a-Kind plant (NOAK))[4].

For FOAK plant using solid fuels the levelised cost of electricity on a 2008 basis is approximately 10¢/kWh higher with capture than for conventional plants (with a range of 8-12 ¢/kWh). Costs of abatement are found typically to be approximately \$150/tCO_2 avoided (with a range of \$120-180/tCO_2 avoided). For NOAK plants, the additional cost of electricity with capture is approximately 2-5¢/kWh, with costs of the range of \$35-70/tCO_2 avoided. Costs of abatement with carbon capture for other fuels and technologies are also estimated for NOAK plants. The costs of abatement are calculated with reference to conventional supercritical pulverized coal (SCPC) plant for both emissions and costs of electricity.

Estimates for both FOAK and NOAK are mainly based on cost data from 2008, which was at the end of a period of sustained escalation in the costs of power generation plant and other large capital projects. There are now indications of costs falling from these levels. This may reduce the costs of abatement so costs presented here may be "peak of the market" estimates.

If general cost levels return, for example, to those prevailing in 2005 to 2006 (by which time significant cost escalation had already occurred from previous levels), then costs of capture and compression for FOAK plants are expected to be \$110/tCO_2 avoided (with a range of \$90-135/tCO_2 avoided). For NOAK plants, costs are expected to be \$25-50/tCO_2

Based on these considerations a likely representative range of costs of abatement for capture (and excluding transport and storage) appears to be \$100-150/tCO_2 for first-of-a-kind plants and plausibly \$30-50/tCO_2 for nth-of-a-kind plants.

The estimates for FOAK and NOAK costs appear to be broadly consistent in light of estimates of the potential for cost reductions with increased experience. Cost reductions are expected from increasing scale, learning in relation to individual components, and technological innovation for improved plant integration. These elements should both reduce costs and increase net

[3] First of a kind in this work means a first plant to be built using a particular technology.

[4] Nth of a kind assumes a large number of plants allowing for substantial learning and thus significant cost reductions

output with a given cost base. These factors are expected to reduce abatement costs by approximately 65% by 2030, although such estimates are inevitably uncertain.

The range of estimated costs for NOAK plants is within the range of plausible future carbon prices, implying that mature technology would be competitive with conventional fossil fuel plants at prevailing carbon prices.

The cost premium for generating low carbon electricity with CCS are found to be broadly similar to the cost premiums for generating low carbon electricity by other means, where mid-case estimates for cost premiums over conventional power generation at present are mainly in the range of approximately 10-25 ¢/kWh (except for onshore wind power at good sites where cost premiums are lower). These cost premiums are all expected to decline in future as technologies continue to mature.

The costs presented in this paper mostly exclude costs of transport and storage and value from permanent storage in oil fields with Enhanced Oil Recovery (EOR). Net costs to the economy of emissions abatement by CCS can be reduced or eliminated entirely by the adding the value of additional oil produced if storage of captured CO_2 is accompanied by EOR. EOR may thus be more prevalent for early plants than for later plants because EOR leads to a decrease in the cost of abatement for early plants. This may in turn reduce the average cost difference between FOAK and NOAK plants compared to the case when capture and compression only are considered.

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List of Symbols and Abbreviations

AFUDC	Accumulated funds used during construction
Bbl/d	Barrels per day
BERR	The UK Government's Department for Business, Enterprise and Regulatory Reform
Bn	Billion
Btu	British thermal unit
Btu/kWh	British thermal unit per kilowatt hour
Capex	Capital cost
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CERA	Cambridge Energy Research Associates
CFB	Circulating fluidized bed
CHP	Combined heat and power
CO	Carbon monoxide
CO_2	Carbon dioxide
COE	Cost of electricity
CoP	ConocoPhillips
CST	Concentrated solar thermal
¢/kWh	Cents per kilowatt-hour
EOR	Enhanced oil recovery
EPRI	Electric Power Research Institute
FGD	Flue gas desulfurization
FOAK	First-of-a-Kind
g/kWh	Gram per kilowatt-hour
GE	General Electric
GEQ	GE Total Quench
GERQ	GE Radiant Quench
GT	Gas Turbine
GW	Giga-Watt
H_2O	Water

H_2S	Hydrogen sulphide
HC	Hydrocarbons
Hg	Mercury
HHV	Higher heating value
HRSG	Heat recovery steam generator
IEA GHG	IEA Greenhouse Gas R&D Programme
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
kg/MWh	Kilograms per megawatt hour
KS-1	Kansai-Mitsubishi proprietary solvent
kW	Kilowatts electric
kWh	Kilowatt-hour
lb/MWh	Pounds per megawatt hour
LCOE	Levelised cost of electricity
MDEA	Methyldiethanolamine
MHI	Mitsubishi Heavy Industries, Ltd.
Mills/kWh	Mills per kilowatt-hour (one mill is equal to 0.1 ¢)
MIT	Massachusetts institute of technology
MMscf	Million standard cubic feet
MMscfd	Million standard cubic feet per day
MMt/yr	Million metric ton per year
MW	Megawatts electric
MWh	Megawatt-hour
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NOAK	Nth-of-a-Kind
NOK	Norwegian krone
NOx	Oxides of nitrogen
NPV	Net present value
O&M	Operation and maintenance
O_2	Oxygen
OPEC	Organization of the Petroleum Exporting Countries

Opex	Operating cost
Oxy	Oxy-combustion
PC	Pulverized coal
PCCI	Power Capital Costs Index
ppm	Parts per million
PV	Photovoltaic
S&P	Standard & Poor's
SC	Supercritical pulverised coal plant
SCPC	Supercritical pulverized coal plant with post combustion carbon capture
SFA	SFA Pacific, Inc
SO_2	Sulfur dioxide
SO_3	Sulfur trioxide
SOx	Oxides of sulfur
Sub	Subcritical pulverised coal plant
$/bbl	Dollars per barrel
$/kW	Dollars per kilowatt
$/kW-yr	Dollars per kilowatt per year
$/MMBtu	Dollars per million British thermal units
$/tonne	Dollars per metric ton
tCO_2	Metric tons of carbon dioxide
TCR	Total capital requirement
Tonne	Metric Ton (1000 kg)
Tonne/MWh	Metric Ton per megawatt-hour
TPC	Total plant capital cost
USC	Ultra-supercritical
wt%	Weight percent

1. Introduction

There is a growing interest in carbon capture and storage (CCS) as a means of reducing carbon dioxide (CO_2) emissions. CCS is particularly appropriate for large point sources of CO_2 emissions, including power plants, large industrial facilities, and some natural gas production facilities (where CO_2 can be a significant component of the gas in the reservoir). There is particular interest in CCS for electricity generation from fossil fuels, because the power sector accounts for a large proportion of total CO_2 emissions (about 40% worldwide), and low-carbon electricity is likely to be increasingly in demand for decarbonising other sectors, such as residential and commercial space heating and, potentially, transport.

Most of the technologies necessary for CCS are already demonstrated. However, there are worldwide only four large CCS projects currently in operation, plus some smaller projects. Of these four large projects, three capture CO_2 from natural gas production (at Sleipner and Snohvit in Norway and In Salah in Algeria), and one captures CO_2 from synthetic natural gas manufacture (in North Dakota). No commercial scale power plants have yet been built with CCS.

The lack of experience of CCS in the power sector leads to substantial uncertainty about the costs of low-carbon power generation and thus of CO_2 emissions abatement using CCS. There have been many studies of likely costs, but they differ in a number of ways:

- Their basis and assumptions, for example with respect to the scale of the plant, capture rates and required rate of return on capital;
- The date when they were carried out, which can cause large differences in estimates due to increases in costs of constructing plants in recent years;
- Whether they are for an "Nth-of-a-kind" (NOAK) plants, as in the case of most studies to date, or for a First of a Kind (FOAK) plants; and,

- The detail with which they have examined plant design.

Such differences make deriving useful cost estimates from published studies problematic.

In particular, the costs of FOAK plants are markedly higher than the costs of later plants using the same type of technology. Historically, cost reductions resulting from learning and other factors have been observed to occur for a range of energy and other technologies over many decades (Wright, 1936; Boston Consulting Group, 1968; Argote and Epple, 1990; McDonald and Schrattenholzer, 2001; Taylor, Rubin et al., 2003; IEA GHG 2006). For carbon capture, cost reductions can be expected to be realized from a range of sources. Economies of scale are likely for later plants given the likely smaller scale of FOAK plants. Cost reductions are also expected to be gained from better plant system integration, including elimination of redundant or over-designed components and de-bottlenecking, and from reductions in the use of energy in the capture process, which has the potential to increase net output. Learning is also likely to lower the costs of individual plant components. Cost reductions may also come from shorter construction lead times, less conservative design assumptions due to greater experience and reductions in required rates of return for later plants due to reductions in perceived project risks. However, uncertainty attends to projections in these cost reductions.

This paper seeks to shed light on the costs of carbon capture by reviewing and comparing the available material on costs of capture for both mature technology and early plants, attempting to account for differences where possible. This paper mainly refers to US costs, for which the greatest amount of published analysis is available. It focuses mainly on the capture part of the CCS process (including compression of the CO_2). Capture and compression account for a large proportion of total CCS costs. Furthermore, transport and storage costs vary enormously with volume and distance of transport and type of sink. Indeed, as is briefly considered in Section 4, storage of CO_2 accompanied by Enhanced Oil Recovery (EOR) can lead to sequestration of CO_2, thus adding significant value rather than remaining a net cost. (In this paper when EOR is referred to it is always assumed to be associated with the storage of the injected CO_2). It is therefore more difficult to draw general conclusions for transport and storage, where there may be either a net cost or a net benefit, either of which may vary greatly compared with capture and compression, where costs vary less (although still significantly) between projects.

This paper is structured as follows.

- Section 2 examines the issues that arise in making cost estimates and the resulting difficulty in comparing diverse estimates.
- Section 3 evaluates and compares the results of recent cost studies of NOAK plants for a standardized set of operating and economic parameters. This comparison takes into account the issues highlighted in Section 2 to the extent allowed by information in the published data.
- Section 4 evaluates published cost estimates for proposed FOAK IGCC plants, using pre-combustion capture, including adjustments for the proposed plants' different scales and capture rates. This section also examines the effects of variations in capture rate on the costs of abatement. The effects of revenue from oil produced by CO_2 EOR are briefly considered.
- Section 5 compares the costs for NOAK and FOAK plants, and examines the extent to which future reductions in certain kinds of costs might account for the differences in estimates.
- Section 6 compares two case studies of post-combustion capture from a natural gas processing plant and an oil refinery.
- Section 7 compares the estimates of costs of abatement using CCS presented here with those presented by others, and with plausible carbon prices.

- Section 8 briefly compares the estimates of costs of electricity from plants with CCS with estimates of costs of other forms of low carbon power.
- Section 9 summarises conclusions.

The implications of these conclusions for policy will be addressed in a forthcoming paper.

2. The Difficulty of Deriving Reliable Cost Estimates

Published estimates show a wide range of costs for CCS. The range appears to be due in large part to the variability of project-specific factors, especially:

- the choice of technology and design;
- the scale of the facility;
- the type and costs of fuel used;
- the required distances, terrains and quantities involved in CO_2 transport;
- the scope of costs, for example whether owners' costs[5] are included and whether costs include elements such as CO_2 compression, transport or storage; and
- site specific factors such as topography.

Assumptions about financial parameters such as rate of return can also vary substantially.

Cost estimates may be further affected by the level of detail at which the design has been examined. Early stage engineering designs may understate costs by the omission of some necessary equipment. Even if studies are detailed, uncertainty still remains about the cost of building and running plants in practice, and about their performance.

Variations in cost estimates found in studies can also be attributed to the date of the study and accompanying uncertainty about escalation or de-escalation of costs. The costs of building

[5] Owner's costs – including, but not limited to land acquisition and right-of-way, permits and licensing, royalty allowances, economic development, project development costs, legal fees, Owner's engineering, and preproduction costs.

new power plants have more than doubled since 2003 (Figure 1) (PCCI, 2008), although other indices, such as those of chemicals plant costs, show somewhat less marked volatility. This cost increase has come from rising global demand for basic construction materials, high demand for power generation equipment, and shortages of people and firms available to undertake essential engineering and construction work. There are now indications of falling prices, however, reflecting the effects of falls in commodity prices and reduced demand for new plants. Changes in commodity prices are illustrated by changes in the price of steel, which increased greatly before recently falling (Figure 2) (Metal Bulletin, 2008). Costs may continue to fall in future, but the extent and duration of any fall remains largely uncertain.

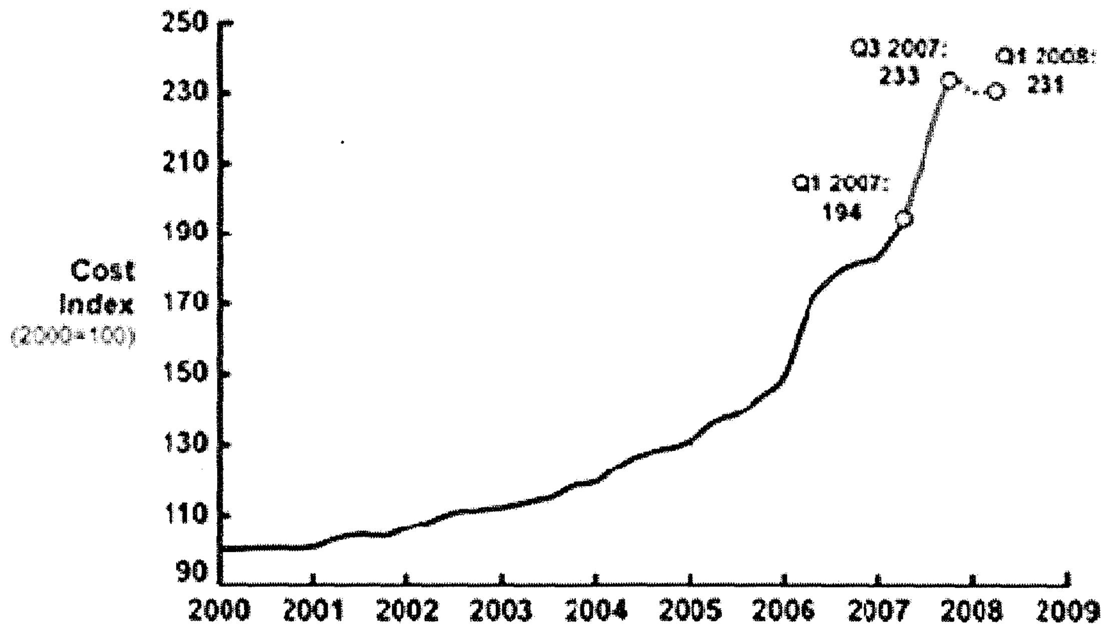

Figure 1: IHS-CERA Power Capital Costs Index (PCCI).

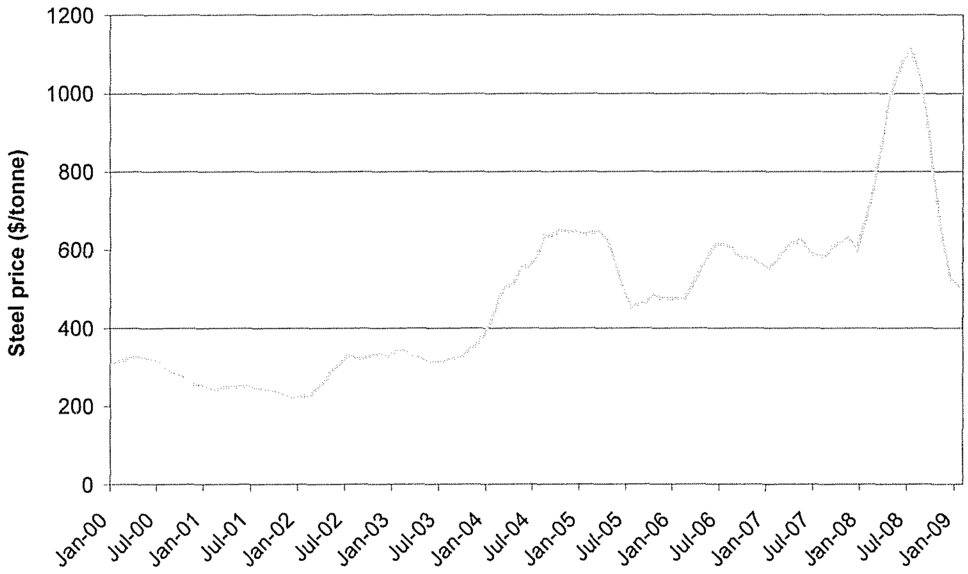

Figure 2: Steel Prices 2000-2009.

3. Estimates of Costs for Nth-Of-A-Kind Plants

There are several published cost estimates for NOAK plants. The technologies covered by the estimates are shown in Table 1 (abbreviations are defined in the symbols and abbreviations section). These studies, published since 2007, typically estimate the required capital cost and levelised cost of electricity (LCOE). LCOE is calculated by modelling the net present value (NPV) of the plant's cash flows, adjusting the electricity price in the model to give a zero NPV. The electricity price which, gives a zero NPV, is the LCOE. The studies that have been reviewed all deal with new plants, not retrofit plants.

The capital costs for each study were developed independently and thus exhibited considerable variation. Differences in the financial and operating assumptions that were used to calculate the LCOE also varied from study to study and further add variability to the estimated LCOE. Annexes A to C show how the assumptions and economics compare across the different studies reviewed. Other studies have been omitted if their basis appeared too inconsistent (Martelli et al., 2008; IEA GHG 2008) or they do not provide enough information to adjust to a common basis (Venkataraman et al., 2007). The IEA GHG 2008 cost update is eliminated from the analysis[6] as it does not appear to be consistent with the other analysis, for example because location and coal type differ.

Table 1: Design Studies Reviewed in Developing NOAK Economics

STUDY	PC					IGCC				NGCC
	SubC	SC	USC	CFB	Oxy	GEQ	GERQ	CoP	Shell	
MIT, 2007	✓	✓	✓	✓	✓	✓	✓			
NETL, 2007	✓	✓					✓	✓	✓	✓
SFA, 2007		✓			✓	✓				✓
Rubin et. al, 2007		✓				✓				✓
EPRI, 2007		✓				✓	✓	✓	✓	✓

Note: NGCC is for post-combustion capture.

3.1 Standardizing the estimates

To allow comparison of the LCOE and cost of CO_2 avoided[7] among these studies, estimates were re- calculated to standardize and thus place them on a common basis.

The total plant cost (TPC) costs, in $/kW, from these studies were escalated to 2008 first quarter US dollars using the IHS CERA Power Capital Costs Index (PCCI). TPC includes engineering and overhead, general facilities, balance of plant, and both process and project contingencies.

The operating and maintenance (O&M) costs were adjusted for inflation using the U.S. Department of Labor consumer price index (CPI, 2008). O&M includes fixed costs such as labor, administration and support, and some maintenance, plus variable costs for chemicals, water, and

[6] Mark Prins, Shell Global Solutions, private communication.

[7] In this paper costs are quoted per tonne of CO_2 avoided relative to a benchmark unless otherwise stated. Costs per tonne avoided are usually higher than costs per tonne captured due to the energy used to run the capture and compression processes and the associated production of CO_2 which leads to tonnes captured being greater than tonnes avoided (though this depends on the benchmark for measuring avoided tonnes).

other consumables, and waste disposal charges. Some costs include both fixed and variable components. A common set of operating and economic parameters was adopted, shown in Table 2.

Table 2: Main Financial Assumptions Applied in Cost Evaluation of NOAK Plants

ASSUMPTION	VALUE	COMMENTS
Required rate of return (pre-tax, real)	10%	The analysis in this work for the NOAK costs is based on pre-tax cash-flows and rate of return. No depreciation or tax calculation is included. Equal to assumption for FOAK plant – see section 5.6).
Inflation	2%	The inflation rate is assumed to be equal for all costs and income in the project life, and is included in the nominal terms interest rate
Construction time	3 to 4 years	The construction time was assumed to be 3 years for NGCC plants and 4 years for IGCC and PC plants
Coal price	$1.8/MMBtu	These fuel prices are on an HHV basis. The analysis is done for Illinois No. 6 bituminous coal. For CFB, lignite is assumed to be used at $1.2/MMBtu.
Natural gas price	$8/MMBtu[8]	On an HHV basis
Capacity factor (years 2-30)	85%	Results for all fuels are presented on this basis to allow easier comparison.
Start up time (year 1)	3 months	3 month commissioning period
Capacity factor, remainder year 1	60%	Reduced load factor (60%) for remainder of year 1
Plant life	30 years	Plant may last longer, but this would lead to little variation in costs.
Owner costs	10% of TPC	Excludes interest during construction. Owner costs vary widely depending on owner and site specific requirements
Accumulated Funds Used During Construction (AFUDC)	Varies with profile	Calculated from the expenditure construction schedule and interest rate. AFUDC is determined from TPC. The actual cash expended for construction is assumed to be spent uniformly at the middle of each year during construction.
Insurance and property taxes	2%	2% of installed costs per year and included as an operating cost
Transport and storage	0 $/tonne	In most CCS systems, the cost of capture (including compression) is the largest cost component

Normalisation is found to reduce variation in the estimates for each technology (See Annex D for detailed information).

[8] 2008 prices averaging $8/MMBtu. U.S. natural gas prices have been consistently over 5.0$/MBtu for the past three years. This sharp gas price rise has resulted in much more serious consideration of clean coal technologies as a means of diversification and fuel cost risk containment.

3.2 Results of the NOAK studies on a common basis

3.2.1 LCOE with and without capture

LCOE for the PC, IGCC and NGCC technologies from the design studies, as recalculated on the standardized basis described above, are shown in Figure 3. All data points are for 90% capture. A brief description of PC, IGCC and NGCC technologies are provided in Annexes A, B and C. The length of the data bar represents the range of estimates, and the points represent the mean of the specific range. The filled circles represent the capture case and the empty circles represent the non-capture case. Where only one study was available a single point is shown.

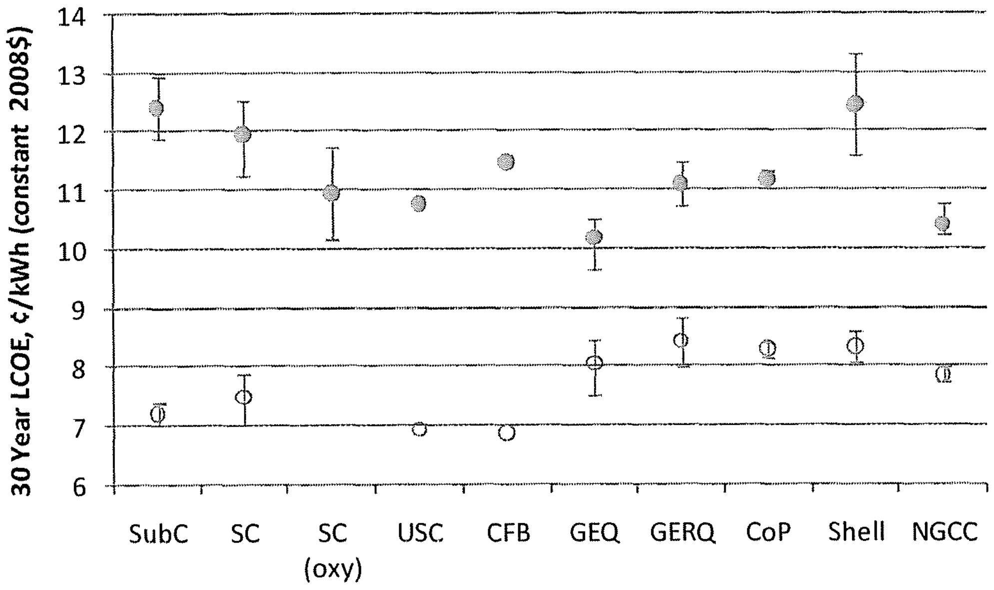

Figure 3: Levelised Cost of Electricity (LCOE) from Design Studies for Normalised Economic and Operating Parameters.

The average normalised LCOEs for plants with capture are all in the range of 10 to 13¢/kWh excluding the costs of transportation and storage. This compares to 7-9¢/kWh for plants without capture, a premium of around 2-5 ¢/kWh.

Variation of LCOEs within these ranges is likely to be well within the range of uncertainties of the estimates, especially as the ranges may include different sets of studies and different studies may refer to different states of technological development. Consequently it appears too early to draw any firm conclusion about which of the technologies might be preferred in which circumstances. However some preliminary remarks can be made from Figure 3 about relative LCOEs of plants with capture, always keeping in mind that any conclusions must be regarded as highly tentative in view of the uncertainties.

- The LCOE decreases when moving from subcritical to ultra-supercritical technology because the benefits of efficiency gains outweigh the additional capital cost (the fuel cost component decreases faster than the capital cost component increases).
- Oxyfuel combustion appears to have a relatively low LCOE in this sample. Oxy combustion is still in the demonstration phase and this early stage of development may lead to some understatement of costs at present, implying costs may be similar to or above those of other technologies in practice. At least one large scale Oxy-fuel project (planned by Saskpower) has been cancelled, reportedly due to rising costs, and replaced with a smaller project.
- The LCOE of CFB is similar to that for the PC cases. This is because cheaper lignite is the feed, and emissions control is less costly. If Illinois #6 coal were used and comparable emissions limits were applied, then the LCOE for the CFB would be significantly higher (MIT, 2007). It is also likely to benefit less in the future from economies of scale than other technologies due to the modular nature of the likely construction.

- The IGCC cost design shows a reduction in LCOE relative to PC designs. The reported Shell IGCC design appears slightly more expensive than GERQ. A H_2O/CO molar ratio >3:1 is needed to ensure adequate conversion of CO and to avoid carbon formation. Shell's design requires steam to do this. The extra steam demand has a marked effect on the output of the steam turbine and the net plant output with capture and therefore on the cost of electricity. In the case of GEQ design the H_2O/CO ratio is ~3/1 and the quench provides the steam required to drive the shift reaction to equilibrium. Hence there is no need to utilize steam from the cycle, leading to less impact on the net power output of the plant and on the levelised cost of electricity (EPRI, 2007). However, there may be other configurations or developments of the Shell design that reduce the costs (Martelli et al., 2008). The three design studies focusing on Shell coal gasification process (NETL, 2007; EPRI, 2007; IEA GHG 2008) all show HHV efficiencies, which are comparable with the commercial IGCC plant in Buggenum started in 1993. Today's best-available-technology is based on modern F-class gas turbines, such as GE 9FB or Mitsubishi 701F4 or Siemens equivalent, but this technology is not reviewed in the literature.

In summary, it should be kept in mind that most of the differences noted are within the range of the uncertainties of the estimates, so the tendencies described here may not be found in practice.

These results focus on bituminous coal-fired power plants. For such plants, IGCC technologies appear to have somewhat lower LCOE with CO_2 capture. Other studies have indicated that for sub-bituminous coal the cost advantage of IGCC over post combustion capture is likely to be reduced (Wheeldon et al., 2006; Stobbs and Clark, 2003) and for lignite, post-combustion capture may be the lowest cost technology (Wheeldon et al., 2006; Davison et al., 2006).

3.2.2 Costs of CO_2 abatement

The cost of abating CO_2 emissions (expressed in $ per tonne of CO_2) can be calculated from the LCOE and assumptions about emissions of plant with and without capture using the standard approach described in Annex F. The cost of abatement is calculated by comparing a plant with capture to its associated reference plant (e.g. IGCC with capture vs. reference IGCC using the same technology but without capture) and by comparing all plants with capture to a common baseline supercritical pulverized coal plant. These comparisons are shown in Figure 4. They indicate a cost of abatement of approximately $35-70/t$CO_2$.

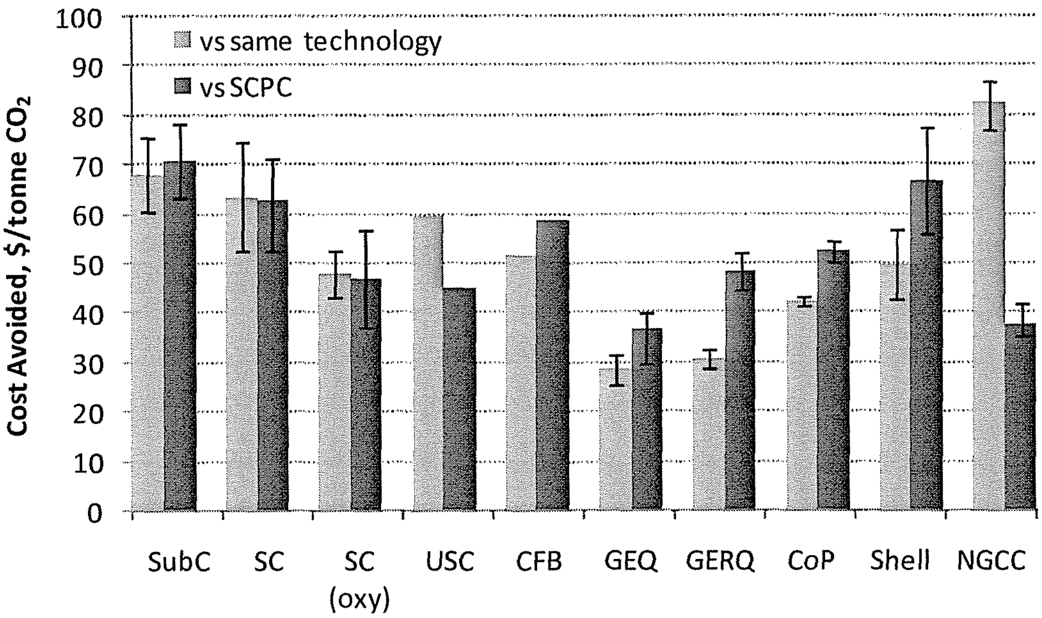

Figure 4: Cost of CO_2 Avoided from Design Studies for Normalised Economic and Operating Parameters for NOAK Plants.

The bars are not exactly identical in the case of SCPC since the average of the SCPC range is used in the calculation. The height of the rectangle represents the average of the specific range of the bar.

The following observations can be drawn from Figure 4:

- CO_2 avoided costs for IGCC plants are mainly less than for PC when a plant with capture is compared with a similar plant without capture. This is because in an IGCC plant, CO_2 removal is accomplished prior to combustion and at elevated pressure using physical absorption, so the incremental costs over a plant without capture are reduced.
- When the cost of an IGCC with capture is compared with the lower costs of a PC plant without capture the differences in estimated abatement costs between PC and IGCC are reduced. This reflects the higher costs of IGCC without capture relative to PC plant. Costs of abatement using NGCC are greatly reduced if compared with SCPC due to the higher emissions of SCPC plant without capture.

4. Estimates of Costs for First-Of-A-Kind IGCC plants

4.1 Comparison of published cost estimates for early IGCC plants

There are several published cost estimates for early IGCC plants. In contrast, there is little published information on early PC projects with post-combustion capture. Post-combustion technology is relatively less well developed than pre-combustion technology, especially at scale. Only Basin Electric's Antelope Valley has published estimates. This plant is relatively small (around 120 MW) and in an unusual set of circumstances so unlikely to be representative. Consequently, we focus on IGCC for the remainder of Section 4[9], Capture from gas fueled plants is considered in the next section.

The plants considered[10] are:

- A U.S.IGCC plant with no capture initially
- A U.S.IGCC plant with 50% capture
- IGCC plants in the USA and Germany, both of which are understood to be designed for high capture rates, assumed to be 90%

Annex E shows the reported capital costs of these IGCC projects. These projects have different scales and capture rates, and so are not directly comparable. To be able to compare them more directly we have adjusted for scale and capture rates to give costs on a standardized basis of approximately 460MW net output plant with 90% capture. There will still be many differences between the projects, for example in fuel choice, technology choice, and location.

The adjustment for scale is based on bottom up modelling of plant at the level of component blocks, such as gasifiers. This modelling indicates that unit capital costs are expected to be reduced by 17.5% by doubling capacity from 250MW to 500MW, with a similar reduction when doubling from 500MW to 1000MW.

The adjustment of capture rates is based on published data on the incremental capital costs and the reduction of output, which suggest that 90% capture leads, for early IGCC plant, to approximately[11]:

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[9] This reflects data availability. Post-combustion capture is expected to play an important role in global emission reduction and evidence on post-combustion costs is considered later in this paper.

[10] The IGCC projects considered are labeled generically because although some information is derived from estimates for particular plants, the adjustment made are generic and conditions at individual plants may differ significantly.

[11] There is a wide range of different estimates for these parameters, see for example Bonsu et al., (2006), White (2008), Mississippi Power (2009), Montel Powernews (2008). Values within approximately the middle of this range are taken in the light of private discussions with power engineers knowledgeable about CCS. The increase in capital costs is taken as the increase in EPC costs, with other costs such as fuel handling and project development assumed to scale pro-rata.

- a 25% increase in capital costs; and
- a 27% decrease in net power output.

Together these imply approximately a 70% increase in capital costs per kW of net power output.

Total overnight capital costs before any adjustment (shown as unadjusted costs in Figure 5) vary widely, due to the very different characteristics of the plant. However costs are similar at around $6400/kW when placed on a standardized basis (shown as adjusted costs in Figure 5). These estimates are inevitably subject to uncertainty, for example in the scope of costs included and the extent to which base data assume future cost escalation during the construction period, and we have therefore adopted a range of $6000-7000/kW as the overnight capital costs of early IGCC plants for the purposes of economic analysis. The upper end of this range includes recognition that some early plant may be smaller than the standardised size of 460MW used for the purposes of comparison.

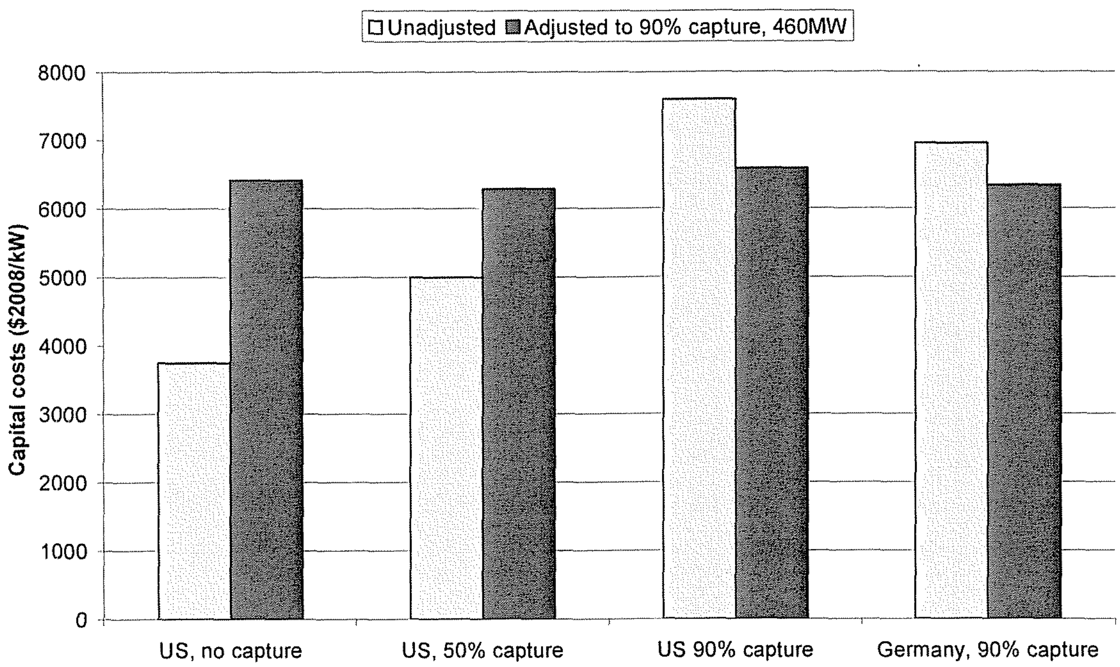

Figure 5: Costs of Early IGCC Plant Adjusted to a Common Basis of 460MW, 90% Capture

4.2 Levelised cost of electricity and cost of abatement for early IGCC plants

The levelised cost of electricity is estimated from these capital costs using the assumptions shown in the table below. Other assumptions are as in Table 2, except that construction time is 5 years and plant life is 20 years. The resulting cost estimates are shown in Table 3.

Table 3: Costs of Electricity and of CO_2 Abatement for Early IGCC Plants

Capital cost ($/kW)	6000	6500	7000
O&M ($/MWh)	1.5	2.0	2.7
Availability	85%	85%	85%
Fuel ($/MMBtu)	1.8	1.8	1.8
LCOE (¢/kWh 2008)	**16.4**	**18.1**	**20.2**
Cost $/t$CO_2$ avoided	**121**	**149**	**179**

Note: The cost of abatement is estimated relative to a cost of generation of 8.0¢/kWh, reflecting costs for SCPC plant on a 2008 basis.

These estimates are mainly based on cost data from 2008, which was at the end of a period of sustained escalation in the costs of power generation and other large capital projects. There are recent indications of costs falling from these levels. If costs are reduced in this way over the longer term the costs of abatement may be reduced from these levels, perhaps greatly, and costs presented here may turn out to be "peak of the market" estimates.

It is too early for reliable indications of the magnitude of cost reductions as insufficient data is available. However, if, for example, general cost levels returned to those prevailing in 2005 or 2006, costs for FOAK plants could fall by approximately 25-30% (depending on the cost index used). This would reduce the central estimate of the cost of abatement to $110/t$CO_2$ avoided (with a range of approximately $90-135/t$CO_2$ avoided), assuming other costs to fall in line with capital costs. Costs in 2005 and 2006 had already risen significantly from costs prevailing earlier in the decade and so such a cost fall would not represent a return to the lowest prices observed in recent years.

The costs of NOAK plants would also be affected by a capex de-escalation. A similar level of capex de-escalation would reduce the NOAK costs from \$35-70/tCO_2 avoided to approximately \$25-50/tCO_2 avoided.

Based on these considerations a likely representative range of costs of abatement from CCS excluding transport and storage costs appears to be \$100-150/tCO_2 for FOAK plants and perhaps \$30-50/tCO_2 for NOAK plants.

4.3 Variation of cost of abatement with capture rate

The cost of abatement and how it varies with the capture rate will depend on both the quantity of the avoided emissions and the costs of avoiding those emissions.

$$\text{Cost of abatement} = \frac{\left(LCOE_{with\,capture} - LCOE_{w/o\,capture}\right)\frac{\$}{MWh}}{\frac{\left(Q_{CO_2,\,w/o\,capture} - Q_{CO_2,\,with\,capture}\right)tonne}{MWh}}$$

Possible reference points for costs and emissions without capture include the following.

- **Case 1:** A modern conventional SCPC plant as a reference point for both emissions and costs of generation: ($LCOE_{w/o\ capture}$ and $Q_{CO2\ w/o\ capture}$). This corresponds to a direct comparison of a new IGCC plant with CCS against a new conventional coal plant without capture. This is the comparison that an investor looking to build a new plant with or without capture would face and thus appears to be the most relevant measure for general analysis of abatement costs.
- **Case 2:** $LCOE_{w/o\ capture}$ and $Q_{CO2\ w/o\ capture}$ are both set by an IGCC without capture. This is likely to be most relevant when an IGCC has already been built without capture and is to be retrofitted with capture.

- **Case 3:** A less efficient coal as a reference point for emissions ($Q_{CO2\ w/o\ capture}$), with the reference point for costs $LCOE_{w/o\ capture}$ being an IGCC without capture. This is relevant, for example, if a decision on capture rate is based on incentives for avoiding emissions relative to a given reference point of less efficient coal plant.
- **Case 4:** A CCGT as the reference point for both emissions and costs of generation: ($LCOE_{w/o\ capture}$ and $Q_{CO2\ w/o\ capture}$).

The results of the modeling for IGCC plant are shown in Figure 6 below. Annex F discusses the mathematical modeling of the effect of capture rate on cost of abatement for early plants, which is stylised but intended to represent robustly the essential characteristics of cost trends. For the purposes of this discussion the absolute numbers are less important than the relative trends.

- **Case 1:** If the baseline is a modern efficient SCPC plant, then costs of abatement are very high at low capture rates but decrease rapidly. This is because the SCPC plant without capture is likely to have a lower LCOE than an IGCC without capture (see section 3). At low capture rates the amount of avoided emissions is relatively small and achieved at cost significantly greater than the costs of capture (because there are additional costs for IGCC without capture). Unit costs of abatement thus decrease strongly with the capture rate against a baseline of an alternative plant without capture.
- **Case 2:** The case of an IGCC with capture compared with a baseline of an IGCC without capture shows costs per tonne change little with capture rate. Depending on exact parameters they may increase with the rate of capture, stay approximately constant (case shown), or decrease slightly. As such it provides no apparent rationale for remaining at lower capture rates. Furthermore, there may be difficulties in practice in retrofitting IGCC plant without capture to achieve higher levels of capture, for example due to the need for the

turbines to burn higher hydrogen mixes. This may imply greater advantages to designing plant for higher capture levels from commissioning.

- **Case 3:** If a less efficient coal plant is chosen as the reference point for emissions avoided then the cost per tonne of abatement is reduced. This is a function of the baseline chosen, which allows a certain tranche of abatement to be credited simply by building a modern, efficient plant. The reduction in cost per tonne is greater at lower capture rates, because of this deemed amount of abatement even at zero capture rates, when no costs of capture are incurred. As such this approach does not reflect costs of abatement relative to an alternative new plant. This indicates that any payment for avoided emissions relative to a fixed baseline may need to be substantially higher at higher capture rates to encourage increases in capture rates.

If a CCGT is chosen as a reference point (not shown on Figure 6) there are no avoided emissions at capture rates below approximately 65%. At greater capture rates cost of abatement per tonne falls rapidly with capture rate, but remains higher than when plant using solid fuels is taken as the baseline.

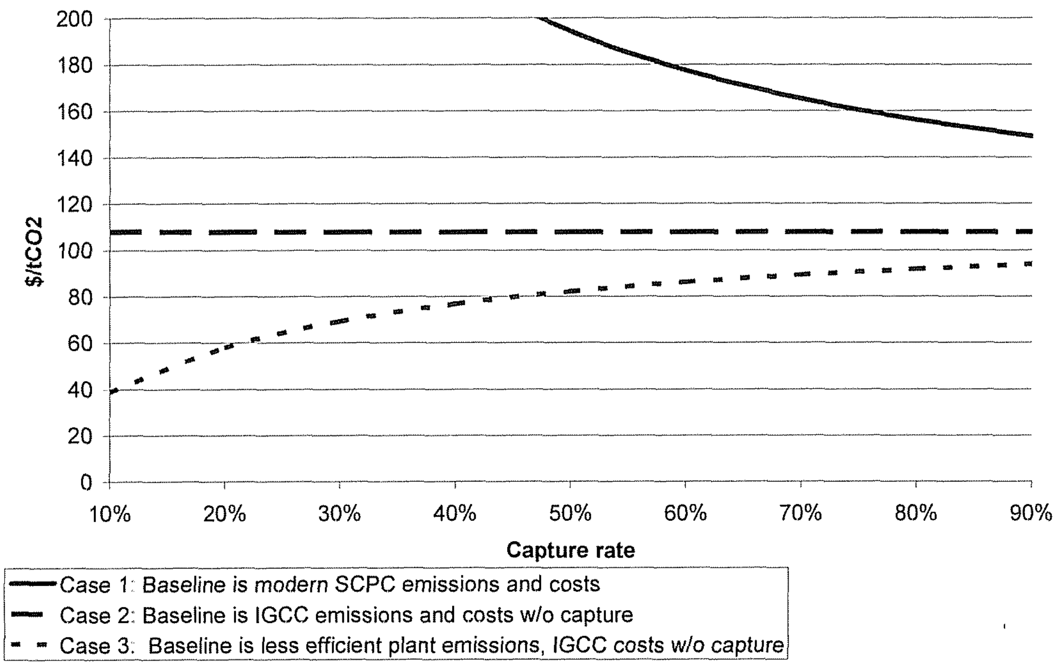

Figure 6: Comparison of Costs of Avoided Emissions

In none of the cases examined does there appear to be any minimisation of costs per tonne avoided by selecting a certain rate of partial capture around the 50% level (although absolute costs of capture are of course lower at lower capture rates simply because less CO_2 is being captured). Indeed for the benchmark of a conventional coal plant, the most relevant for wider analysis of abatement options, costs decrease markedly with increasing capture rates. Lower unit costs of abatement are therefore likely to result if projects are built with high capture rates. There do not seem to be any grounds based on unit cost of abatement to prefer lower capture rates for IGCC plant.

4.4 Value of EOR for first-of-a-kind plants

EOR allows sequestration of CO_2 while providing substantial economic benefits. Where CO_2 is used in EOR schemes, high enough oil prices could make CCS technology competitive with conventional generation if the full net value of the additional oil is credited to the capture project. As an example, a hypothetical project (Friedman et al., 2004) proposes the following:

1. Increase oil production from10,000 bbl/d to 40,000 bbl/d, recovering an additional 150 million barrels of oil during a 20 year period.
2. Increase associated gas production from 10 MMscfd to 185 MMscfd, while CO_2 content in the associated gas increases from 4% to 77%.
3. Inject 122.5 MMscfd of CO_2 (5 Mscf/bbl) throughout the project to obtain this additional oil recovery.

This analysis is based on a 500 MWe (net power output) IGCC plant with the same assumptions for FOAK IGCC as in section 4.2. The plant produces about 10,000 tonnes of CO_2 per day and utilizes carbon capture. This analysis is based on the following cost data:

- The IGCC plant capital cost including capture is about $3.25 billion.
- Pipeline capital cost is $80 million (50 mile, 20-in pipeline) for transporting the recovered CO_2 to the oilfield. Operating cost is $0.12/Mscf CO_2.
- The capital cost of recycle compression for the associated gas and CO_2 makeup is $90 million. This example assumes a simple recycle of the associated gas because of the low flow rate of natural gas from this field.
- The CO_2 injection pump system has a $15 million capital cost.
- The production portion of the EOR will require material of construction upgrades because of the increasing CO_2 content as the flood progresses. This example assumes a $100 million cost.

- The cost of CO_2 injection wells varies significantly among projects, depending on the number of existing wells that can be converted to CO_2 injection, the maximum capacity of new injection wells, well depth, and field location. Well costs can vary from less than \$1/bbl to more than \$10/bbl of produced oil. This analysis assumes the operating costs of injection wells to be \$5/bbl.

Based on these assumptions, the project requires about \$75/bbl crude oil price to achieve a net zero cost of abatement. A higher crude oil price will increase the return on investment. Figure 7 shows the relationship of oil price and cost of CO_2 when EOR is included. It covers the value chain as a whole. In practice the value of the EOR is likely to be distributed between the CCS project, the reservoir owner, and the government (through taxes or royalties), and is unlikely all to accrue to the capture part of the chain project.

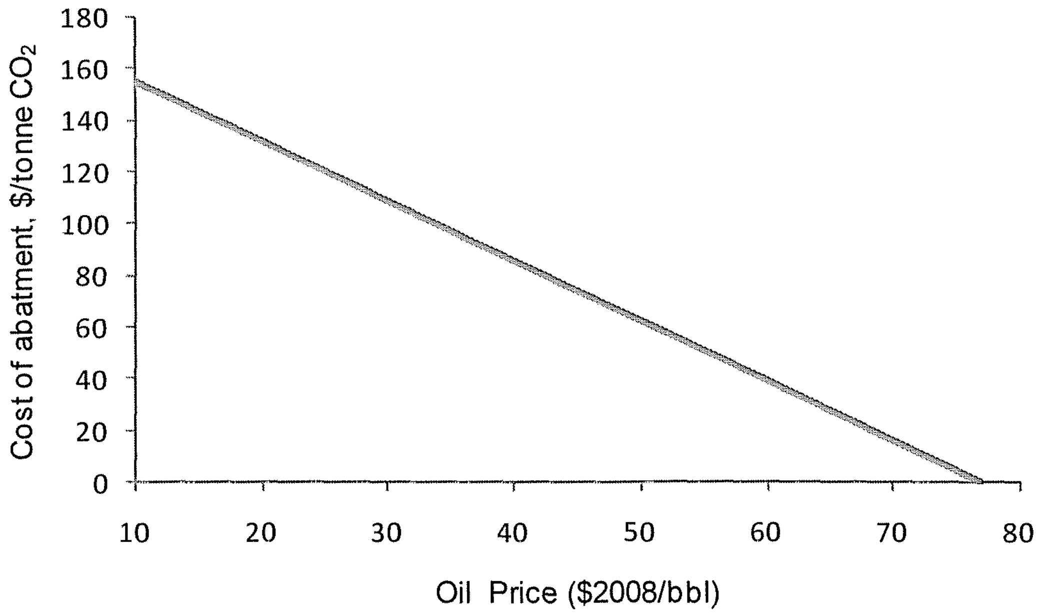

Figure 7: Value of EOR for Early IGCC Deployment

In estimating the cost of abatement with CCS we assume no effect on total carbon emissions from the oil produced. The effect of the additional oil production on emissions is complex and depends on a range of interactions. For example extra production may affect oil prices and hence gas prices in markets where these are linked, and therefore affect the competitive position of gas versus coal. The effect on emissions will also depend on the form of any emissions caps.

The simplest model is that additional conventional oil reduces the production of more expensive non-conventional resources, which are likely to be the marginal sources of oil supply in the long term, but does not significantly affect the global oil price, for example because of the shape of the supply curve for non-conventional oil or the effect of OPEC on the market. In this model global oil consumption is unaffected and, as the production of non-conventional reserves is energy intensive, there is an abatement benefit from producing additional conventional oil through EOR. Emissions would also be unaffected if a binding emissions cap covered all relevant markets.

5. Consistency between Estimates of Costs for Early Plant with Costs of Nth Plants

The costs of abatement for FOAK plants (excluding the benefit of EOR) is estimated as approximately \$120-\$180/tCO_2 on a 2008 basis. In contrast, the estimated costs for NOAK plants are much lower at \$35-70/tCO_2. In this section we examine if this difference can be accounted for by future cost reductions with experience.

Cost reductions for technologies are typically expressed as a learning rate, the percentage decrease in costs for each doubling of cumulative production. Learning rates have differed greatly for different energy technologies historically. In the case of IGCC with CCS it is difficult to estimate a future learning rate by the usual means because there is no historical data on CCS cost reductions, very limited deployment to date, and analogues in other sectors offer only a limited match with CCS. Reflecting these factors, learning rates have been estimated in this work by disaggregating cost reduction with experience into components for which estimates can more reliably be made than for an overall learning rate. Each of these factors is likely to influence both capex and opex, although the precise magnitude of the effect may be different.

The precise timing and magnitude of any decreases is inevitably uncertain. Among the reasons for uncertainty in the rate of achievable cost reduction is that the time taken to design and build an IGCC with CCS is several years. It will therefore be more challenging to achieve rapid learning over a number of technology cycles than with other types of technology with shorter cycle times. Consequently, the cost reductions indicated here are likely to depend on early demonstration plants being built so as to allow time for experience to be gained to allow reduce costs for subsequent generations of plant.

5.1 Scale

Projects are likely to be at larger scale in future. For example, both Futuregen and Hydrogen Energy's proposed plant in California, for which a permit application has been submitted, have net output in the range 250-275MW. Other early plants may be of approximately 400-500MW scale. It is expected that eventually plants will have total output of 1-2GW, comprising more than one unit at a site, a scale typical of other baseload power plants.

The effects on costs of such scale increases can be estimated using standard bottom-up cost estimation methods. These examine the effect of scale of the unit cost of components such as turbines, where capacity increases more rapidly than costs as scale increases. The benefits of a single site for more units can also be assessed.

These estimates indicate that each doubling of scale reduces unit costs by approximately 15-20% for IGCC plants, with a central estimate of 17.5%. One such doubling is included in the estimate of future cost reduction. In practice, the typical scale of plant may more than double over the period.

5.2 Integration and innovation

Improved process integration, reduced redundancy and technological innovation on individual components all have the potential to contribute to cost reductions. The processes involved in an IGCC plant with CCS are complex with many steps, so there is likely to be potential for more efficient system integration as experience is gained. Furthermore, some parts of the plant are in the early stages of the technology development cycle, notably gas turbines burning hydrogen, so significant technological advances may be possible. Future advances in these areas can be hypothesised and their effects on costs estimated.

The reduction in unit costs comes from two separate effects. First, improved integration and innovation can reduce capital costs. Second, total net power output for a given capital cost can be increased as auxiliary load is reduced by better process integration and more efficient individual processes.

For the purposes of this analysis elimination of redundancy was assumed to remove the need for specific pieces of equipment in the plant, reduce the cost of the power island and reduce the auxiliary load and thus increase the net output of the plant. Together these may have the potential to reduce total costs per kW by 8-12% or more by 2030.

5.3 Learning on individual components

Historical data on existing installed capacity of process components such as gasifiers and learning rates exists for many parts of an IGCC plant, so future cost reductions can be extrapolated from this using standard learning curve approaches.

Learning on individual components is estimated to reduce costs by a cumulative total of 12-15% assuming no technological discontinuities (as technology step changes are captured in the integration and innovation category). This is equivalent to a learning rate of only some 3-4% for each doubling of IGCC capacity. The reason for this relatively slow learning rate is that many of the components of IGCC plant are relatively mature technologies. The addition of IGCC capacity thus represents much smaller increments of cumulative capacity for the components than it does for IGCC plants as a whole.

5.4 Aggregate learning rate and effect on costs

Together the costs savings identified above yield a total cost reduction of around 40% on LCOE. This total can be taken with other assumptions to derive an overall learning rate estimate. This can then be compared with other power generation technologies. The comparison here is based on an assumption of worldwide capacity of pre-combustion capture of approximately 50-100 GW by 2030 from an initial tranche of 3GW of capacity in the next few years. This is equivalent to four or five doublings of capacity over that period.

On this basis, the sources of cost reduction identified totalling 40% cost reduction are equivalent to a total learning rate of 10-12%. This is broadly consistent with learning rates for other power generation technologies reported in the literature[12], with the exception of solar PV which, at times, has experienced a learning rate of approximately 20%[13] and nuclear energy where reliable cost data is difficult to obtain but learning rates appear to be lower, or even negative [14].

[12]See for example studies of costs of renewables including http://www.nrel.gov/docs/fy04osti/36313.pdf, http://www.solarpaces.org/Library/docs/STPP%20Final%20Report2.pdf

[13] See e.g. (http://www.iop.org/EJ/article/1748-9326/1/1/014009/erl6_1_014009.pdf?request-id=53776976-16a0-4eea-8240-48e23b949307)

[14]See for example http://www.sciencedirect.com/science?_ob=ArticleURL&_udi=B6V2W-42349CF-1&_user=7018201&_rdoc=1&_fmt=&_orig=search&_sort=d&view=c&_acct=C000011279&_version=1&_urlVersion=0&_userid=7018201&md5=c055f88034a4ed68cb3f904e11440542

To summarize, the estimated learning rate for CCS here is based on an analysis of the disaggregated effects combined with some additional assumption about the number of doublings to provide a comparison with other technologies.

5.5 Effect on LCOE

The three types of cost reduction with experience identified together have, as noted, the potential to reduce LCOE by some 40% by 2030. This reduces the cost of abatement relative to conventional coal plants by some 65%, from approximately \$150/tCO_2 avoided to approximately \$50/tCO_2 avoided in a central case estimate based on 2008 costs. The proportional change in the cost of abatement is larger than the change in cost of electricity because the benchmark cost of generation with emissions decreases by less than the cost of generation with carbon capture. Costs of IGCC with carbon capture reduce from approximately 18¢/kWh to 11 ¢/kWh, a decrease of 40%. However costs of conventional coal plant, which forms the benchmark, may decline much more slowly because the technology is mature. For example, the cost of continued generation may decline from 8¢/kWh to 7.5 ¢/kWh. In this case the premium for plant with capture declines by much more proportionately than the power price – from 10 ¢/kWh to 3.5 ¢/kWh in this case, a decline of 65%.

The costs for abatement from mature technology (NOAK) shown here are broadly consistent with the analysis for NOAK plants reported in Section 3, the abatement cost of \$50/tCO_2 being well within the range of \$35-70/tCO_2 shown in section 3. This implies that the effects of scale, system integration, and technological learning by-doing can largely account for the difference between estimated FOAK and NOAK costs, although other factors such as those noted in the introduction to this paper may also play a role.

Consistent with this analysis some 50-100 of GW of capacity may need to be deployed worldwide to achieve costs equivalent to the NOAK costs reported in Section 3. However, the precise timing and magnitude of cost reductions remain inevitably uncertain.

5.6 The effects of lower risks

The financial modelling for this work has assumed the same rate of return for both FOAK and NOAK projects, in order to allow for more direct comparison of results. It is possible that a lower rate of return will be required for NOAK projects, which could lower costs of abatement. For example, there is some recognition that the risks of early plant using less mature technologies a rate of return perhaps one to two percentage points higher is appropriate[15]. The assumed rate of return (10% real pre-tax) used in this work appears roughly comparable with these precedents for early plants[16]. If a lower rate of return were required by NOAK plants, this could lead to a further reduction in costs for NOAK plant below those shown in section 3, or to costs of abatement still being at the levels shown even if some of the savings on capital or operating costs described in this section are not realised.

6. Comparing Costs of Capture from Industry

6.1 Natural gas processing plant

Saudi Aramco and Mitsubishi Heavy Industry, Ltd., (MHI) carried out a feasibility study in 2005 to determine the best option for capturing a total of 1.4 million tonnes per annum of CO_2 from two natural gas plants, although the capture is not from the gas streams themselves[17]. The two gas plants were built to process associated and non-associated gas and were referred in this

[15] E.g. Virginia HB3068, SB11416, California resolution E4182.
[16] Depending on tax rate, assumed gearing and other factors.
[17] Saudi Aramco, private communication.

work as Gas Plant 1 (GP1) and Gas Plant 2 (GP2). The following five cases were selected for the study. All were found to be technically feasible except case 4.

Case -1 2,100 tonnes per day from Boilers of GP1 and 2,100 tonnes per day from GP2

Case -2 2,100 tonnes per day from Boilers of GP1 and 2,100 tonnes per day from Gas Turbines of GP1

Case -3 4,200 tonnes per day from Gas Turbines of GP1

Case -4 4,200 tonnes per day from Thermal Oxidizers of GP1

Case -5 4,200 tonnes per day from Acid Gas of GP1

Capex and costs of CO_2 capture per tonne are summarized in Table 4 for each case. Capex consists of the initial investment cost of capture, the cost of compression and the cost of the auxiliary utilities. The technology chosen for post-combustion CO_2 capture from flue gas was the MHI's proprietary KM-CDR Process (Kansai-Mitsubishi Carbon Dioxide Recovery Process). Annex G contains additional details of the five cases.

Case 5, which is CO_2 recovery from acid gas, is the lowest in cost among all the cases studied. Acid gas enrichment was assumed to be used to recover CO_2 from the acid gas stream, with a 50 wt% MDEA solution.

Table 4: Comparison of Capex and Costs of CO_2 (in $ 2005)

	CO_2 Capture Scenario	CO_2 Delivery Cost $/tonne	CAPEX Million US $
Case 1	Boilers (GP1 & GP2)	22.0	160.7
Case 2	Boilers & GT GP1	26.2	153.3
Case 3	GT GP1	32.2	172.4
Case 4	Thermal Oxidizers GP1	28.8	169.8
Case 5	Acid Gas GP1	16.0	124.0

Note: The CO_2 delivery cost is reported as $ per tonne of CO_2 "captured".

6.2 Oil refinery

One recent study (StatoilHydro, 2008) for the carbon capture facility at the Mongstad oil refinery near Bergen in Norway has shown that post-combustion CO_2 capture is technically feasible, but the costs are much larger than indicated by the Aramco study described above.

The Mongstad project will be developed in two phases to reduce technical and financial risk. Phase 1 includes capturing at least 80,000 tonnes of CO_2 using chilled ammonia and 20,000 tonnes of CO_2 with improved amine technology. The test facility is due for completion by 2009-2010, and will be 12–18 months in test. The goal of the test facility is to develop the most cost effective method to capture CO_2 from flue gases using post-combustion capture.

Phase 2 involves full-scale CO_2 capture from both the combined heat and power plant (CHP) station and the catalytic cracking plant. These two sources will amount to approximately 80% of the refinery's CO_2 emissions when the combined heat and power plant is in full operation in 2010. The project will capture approximately 1.2 million tonnes of carbon dioxide per year from the combined heat and power plant, and approximately 0.8 million tonnes per year from the cracking plant.

StatoilHydro has estimated the total capital costs for both capture facilities and their joint systems to be around NOK 25 billion (US$3.5 billion) with -30%/+40% uncertainty. Fifty percent of the capex relates to the capture facility for CHP, 20% to the capture facility for the cracking plant, and 30% to joint systems for both capture sources.

In addition to the capital costs, StatoilHydro estimated that the annual operating expenses for the two capture facilities to be NOK 1.0 billion to 1.7 billion per year. On this basis, the costs of capture per tonne of CO_2 were estimated to be NOK 1,300-1,800 (2008 US$ 185-255) at a 7% rate of return.

6.3 Comparison with natural gas plant capture

Table 5 looks at some key areas for comparison between the two estimates of StatoilHydro and Saudi Aramco. The factors that might explain the very large difference in the costs can be summarised as follows.

- Technology choice (MHI vs. chilled ammonia).
- The two estimates were in the early stage and therefore uncertainty is as high as -30%/+40 %.
- In the Middle East, the operating and labor costs are much lower than in Europe.
- Project definition and project development phases were not included in the Aramco estimates.

Table 5: Comparison between CO_2 Capture at a Natural Gas Processing Plant and an Oil Refinery

	Saudi Aramco Capture Study		Mongstad Refinery Capture Project	
CO_2 source	Thermal Oxidizer	Gas turbine	Cat Cracker	CHP
Flue gas	SOx and HC	-	catalyst particles, SO_2 and NOx	-
Fuel	-	Natural gas	-	Natural gas
Capital Costs	$0.191 bn	$0.194 bn	$0.7 bn	$1.75 bn
Operating Costs (1/yr)	US$ 0.025 bn	US$ 0.029 bn	US$ 0.15-0.25 bn	US$ 0.15-0.25 bn
Pretreatment Costs	High	No	High	No
Capture technology	MHI KS-1	MHI KS-1	Chilled ammonia/amine	Chilled ammonia/amine
Technical Challenge	Yes	No	Yes	No
Commercial Experience	Mature	Mature	Still considered new technology	Still considered new technology
CO_2 Captured	1.3 MMt/yr	1.3 MMt/yr	0.8 MMt/yr	1.2 MMt/yr
Cost of Capture	US$ 32/tCO_2	US$ 36/tCO_2	US$185-255/ tCO_2	US$185-255/ tCO_2

Note: the cost of the joint systems of the two capture plants at the Mongstad project is not included in the capital costs in the table

- The uncertainty about the cost level is also due to the uncertainty relating to the market conditions for materials, equipment and personnel at the time at which the investment decision is made and during the implementation period. The Mongstad project estimates were made in 2008. However, in the case of Saudi Aramco, the estimates were made in 2005 in a period where industrial prices were more stable and lower.

However, the difference between the two estimates is large and may not be entirely accounted for by these factors alone. For example, the Aramco study used an early stage estimate provided by MHI for a project in Saudi Arabia. As such, it may not represent realisable full project costs, and may not be applicable to circumstances in Europe or the USA.

6.4 Comparison between pre- and post-combustion capture from a gas plant

The expected capital cost reported for the Masdar/Hydrogen Energy 400MW pre-combustion plant in Abu Dhabi is $2 billion[18], 43% less than the capital costs estimated by Statoil for Mongstad. However the amount of CO_2 captured is only 15% less. The Abu Dhabi project costs include the power plant, which is excluded from the Mongstad costs. The Abu Dhabi costs exclude CO_2 transportation and storage. There is expected to be revenue to the project from the sale of CO_2 due to its value for EOR.

7. Comparison with Other Recent Estimates of the Costs Abatement with CCS and with the Carbon Price

7.1 Comparison with other estimates of the cost of CCS

Other estimates of the cost of abatement using CCS technologies have been published recently by industry participants and observers. These are summarised in Table 6. The data are taken from a range of sources, including press reports. The basis of the costs is not always stated but most appear to include transport and storage costs.

The following conclusions were drawn from the comparison:

- The costs for FOAK plant quoted here are above those quoted by others, although the bottom of the range of costs reported here for FOAK plants is broadly in line with the higher of the estimates from other parties.

[18] www.hydrogenenergy.com

- The costs for NOAK plants shown in this work are in line with other estimates. The case with capex de-escalation appears to fall below other estimates, but if transport and storage costs were included, the estimate in this work would be likely to fall in line with the other estimates, based on inspection of estimates for typical transport and storage costs in the literature.

Table 6: Estimates of Costs of CCS ($2008/t$CO_2$ avoided)

Estimate Source	Costs now	Future costs (2030)
Boston Consulting Group (2008)[19]	70	45
McKinsey (2008)[20]	80-115	40-60
S&P (2007)[21]	-	40-80
BERR (2006)[22]	-	40
Shell (2008)[23]	130	65 or below
Chevron (2007)[24]	Significantly greater than 100	n/a
Vattenfall (2007)[25]	45	25-45
This work (excluding transport and storage)	**120-180 on a 2008 basis 90–135 with capex de-escalation**	**35-70 on a 2008 basis 25-50 with capex de-escalation**

Note: Estimates rounded to nearest $5. Some sources do not state basis of estimate and are assumed to be $2008.

7.2 Comparison with carbon price projections

The range of estimated costs for later NOAK plants of $35-70/t$CO_2$ avoided is within the range of predicted future carbon prices if an illustrative $20/t$CO_2$ is added to allow for the costs of transport and storage. For example a mid-case MIT projection shows a carbon price of

[19] http://www.bcg.com/impact_expertise/publications/files/Carbon_Capture_and_Storage_Jun_2008.pdf

[20] €60-90/tCO_2 for typical early demonstration project, €30-45/tCO_2 by 2030, An exchange rate of 1.3$/€ is assumed. http://www.mckinsey.com/clientservice/ccsi/pdf/CCS_Assessing_the_Economics.pdf

[21] http://www2.standardandpoors.com/spf/pdf/events/PwrGeneration.pdf

[22] http://www.berr.gov.uk/files/file42874.pdf

[23] Timesonline. 50- 100 Euros, with earlier project closer to the top of the range. An exchange rate of 1.3$/€ is assumed.

[24] Point Carbon 13.09.07

[25] http://www.vattenfall.com/www/ccc/ccc/569512nextx/574152abate/574200power/574251abate/index.jsp

\$78/tCO_2 avoided in 2030[26] (in real terms \$2007). This implies that mature CCS technology would be competitive with conventional fossil plants at prevailing carbon prices.

8. Comparison with the Costs of other Low Carbon Generation

It is beyond the scope of this paper to carry out a detailed review of the relative costs of different forms of low carbon generation. Such costs vary widely, in particular with site characteristics. However it is useful in the context of this paper to briefly consider some benchmarks with which the cost of generation using CCS can be compared.

LCOEs estimated on a common basis for different types of low carbon generation and for conventional fossil fuel generation are shown in Figure 8. Ranges are shown to recognise the wide variations that are present, and even then individual project costs may lie outside the ranges shown.

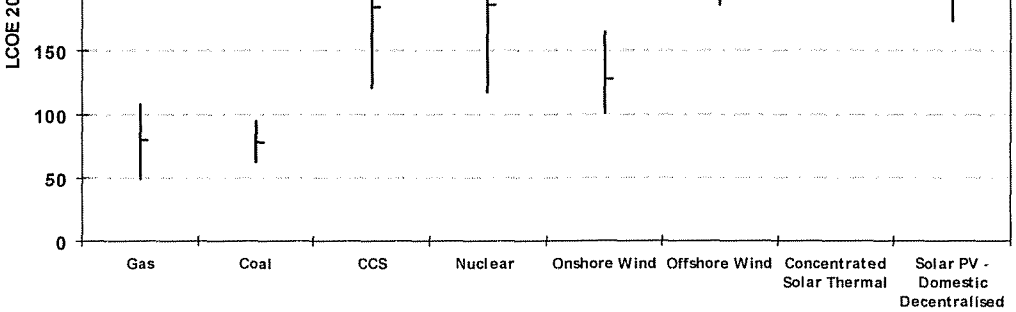

Figure 8: Relative Costs of Low Carbon Electricity Generation. Source: Estimates by Hydrogen Energy Based on a Return of 10% (Nominal Post-Tax).

[26] Mid-case projection taken from "Assessment of U.S. Cap-and-Trade Proposals", by Paltsev et al, MIT 2007

The costs shown exclude:

- a carbon price;
- transmission and firming costs for renewables (and the benefits of avoided transmission and distribution costs for decentralised solar PV);
- the benefit of existing support, such as tax breaks.

The range for CCS includes allowances for transport and storage costs or some EOR benefits. Costs are higher for all technologies than those sometimes quoted. The reasons for this include:

- the timing of the cost estimates as being in 2008, following escalation in capital costs,
- exclusion of existing support, which is often netted off before quoting costs; and
- inclusion of the full costs of a project, including for example owners' costs and in the case of nuclear, likely out-turn costs when the plant is completed rather than initial estimates that are subject to increase as projects progress.

The estimates indicate that onshore wind at a good site is the lowest cost form of low carbon electricity generation (excluding intermittency costs). CCS costs are broadly comparable with those of nuclear plants and offshore wind. The top end of the CCS cost range is comparable with the costs of Concentrated Solar Thermal (CST), but with a likely cost below that of solar PV.

This pattern of costs is expected to change in future as technology costs decline at different rates, reflecting current differences in maturity (as measured by installed capacity). Costs of less mature technologies such as solar and CCS may fall more rapidly than those of more mature technologies such as nuclear, and to a lesser extent, wind. A scenario for costs in 2030 is presented in Figure 9. This scenario assumes substantial amounts of all of the low-carbon technologies shown being deployed by that date. It shows most low carbon technologies converging to a cost of $150/MWh ($2008), with onshore wind being the lowest cost.

Costs of avoided emissions are somewhat lower for other technologies than those for CCS plants at the same LCOE because there are some residual emissions from plant with CCS. However costs per tonne of CO_2 avoided relative to a conventional coal plant show approximately the same general pattern. Costs of abatement may also need to take account of lifecycle emissions, especially where the emissions from some inputs are outside any carbon pricing regime.

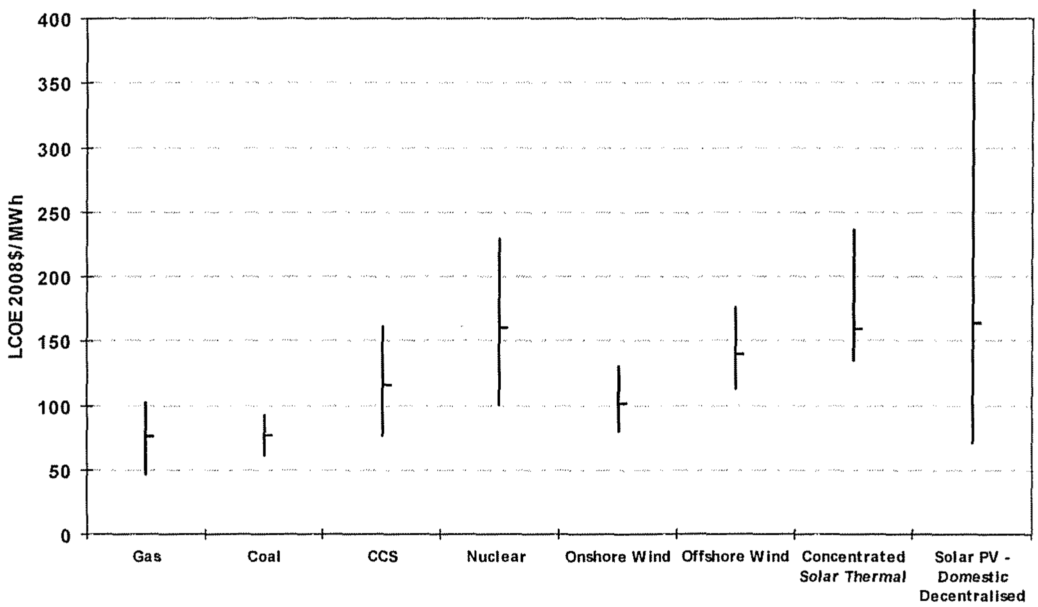

Figure 9: Cost Scenarios for 2030

9. Conclusions

The main conclusions from this work are as follows:

1. The costs of carbon abatement on a 2008 basis for FOAK IGCC plants are expected to be approximately \$150/tCO_2 avoided (with a range \$120-180/tCO_2 avoided), excluding transport and storage costs and revenue from EOR.

2. 2008 may have represented a peak in costs for capital-intensive projects. If capital costs de-escalate, as appears to be happening, then these costs may decline. if general cost levels were to return to those prevailing in 2005 to 2006, for example, the costs of abatement for FOAK plants would fall by perhaps 25-30% to a central estimate of some \$110/tCO_2 avoided (with a range of \$90-135/tCO_2 avoided).
3. Consequently, the realistic costs of FOAK plant seem likely to be in the range of approximately \$100-150/tCO_2.
4. Based on data from Statoil, the cost of post-combustion capture appears likely to be above the top end of the range. Other work by Saudi Aramco indicates potential for lower costs for post-combustion capture. Pre-combustion capture from natural-gas fueled plant may offer lower costs of abatement if the same baseline for emissions is applied as for solid-fueled plant and if gas prices are low.
5. The costs of subsequent solid-fueled plant (again excluding transport and storage) are expected to be \$35-70/tCO_2 on a 2008 basis, reducing to \$25-50/tCO_2 allowing for capex de-escalation. This estimate is consistent both with published studies of the costs of NOAK plants and estimates based on modelling the potential reductions in costs from costs of FOAK plant due to improvements in scale, plant integration and technology development.
6. The FOAK estimates are higher than many published estimates. This appears to represent a combination of previous estimates preceding recent capital cost inflation, greater knowledge of project costs following this more detailed study, and the additional costs of FOAK plants compared with the NOAK costs quoted in any published estimates.

7. The value of EOR can reduce the net cost of CCS to the economy to zero as oil prices approach approximately $75/bbl for FOAK plants if the full net value of the EOR accrues to the project.
8. Costs of abatement vary with capture rates in ways that depend strongly on the baselines chosen for emissions and costs. Costs of abatement decrease with increasing capture rates if the baseline is the costs and emissions of a modern SCPC plant.
9. Costs of generating low carbon power using other technologies appear similar to or above the costs of generation from IGCC plants with CCS, except for onshore wind plants, which have lower costs when located at favourable sites (excluding transmission and intermittency costs).

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Annex A: Summary of PC Design Studies — As Reported

STUDY	MIT	MIT	MIT	MIT	MIT	Rubin	NETL	NETL	EPRI	SFA	SFA
Technology[b]	SubC	SC	OXY	USC	CFB	SC	SubC	SC	SC	SC	OXY
Cost year basis	2005	2005	2005	2005	2005	2005	2006	2006	2006	2006	2006
Without Capture											
Net Power (MW)	500	500		500	500	528	550	550	600	600	
CO_2 emitted (lb/MWh)	931[i]	830[i]		738[i]	1030[i]	811[i]	1,886	1,773	1,843	0.81[j]	
Efficiency (%, HHV)	34.3	38.5		43.3	34.8	39.3	36.8	39.1		39.5	
Heat rate (Btu/kWh)	9,950	8,870		7,880	9,810		9,276	8,721	8,963	8,630	
TPC ($/kW)	1,280	1,330		1,360	1,330	1,442[a]	1,549	1,575	1,763	1,703	
FCF (% on TPC)	15.1	15.1		15.1	15.1	14.8	16.4	16.4	11.7	15	
Fuel price ($/MMBtu)	1.5	1.5		1.5	1.0	1.2	1.8	1.8	1.5	1.53	
Capacity Factor (%)	85	85		85	85	75	85	85	80	85	
Electricity cost											
COE_{CAP} (¢/kWh)	2.60	2.70		2.76	2.70				2.927	3.43	
$COE_{O\&M}$ (¢/kWh)	0.75	0.75		0.75	1.00				1.051	1.14	
COE_{FUEL} (¢/kWh)	1.49	1.33		1.18	0.98				1.344	1.32	
COE (¢/kWh)	4.84	4.78		4.69	4.68	5.30	6.40	6.33	5.322	6.13[l]	
With Capture											
Net Power (MW)	500	500	500	500	500	493	550	546	550	548	542
CO_2 emitted (lb/MWh)	127[i]	109[i]	104[i]	94[i]	141[i]	107[i]	278	254	277	0.10[j]	0.07[j]
Efficiency (%, HHV)	25.1	29.3	30.6	34.1	25.5	29.9	24.9	27.2		31.2	30.2
Heat rate, Btu/kWh	13,600	11,700	11,157	10,000	13,400		13,724	12,534	12,300	10,946	11,315
TPC($/kWe)	2,230	2,140	1,900	2,090	2,270	2345[a]	2,895	2,870	2930	2,595	2,620
FCF (% on TPC)	15.1	15.1	15.1	15.1	15.1	14.8	17.5	17.5	11.7	15	15
Fuel price ($/MMBtu)	1.5	1.5	1.5	1.5	1.0	1.2	1.8	1.8	1.5	1.53	1.53
Capacity Factor (%)	85	85	85	85	85	75	85	85	80	85	85
Electricity cost											
COE_{CAP} (¢/kWh)	4.52	4.34	3.85	4.24	4.60				4.892	5.23	5.28
$COE_{O\&M}$ (¢/kWh)	1.60	1.60	1.45	1.60	1.85				1.52	1.74	1.76
COE_{FUEL} (¢/kWh)	2.04	1.75	1.67	1.50	1.34				1.845	1.67	1.73
COE (¢/kWh)	8.16	7.69	6.98	7.34	7.79	8.80	11.88	11.48	9.278[d]	9.25[m]	9.54[g]
Comparison											
Avoid cost ($/tonne)	41.3[f]	40.4[f]	30.3[f]	41.1[f]	39.7[f]	49.7[f]	68[e]	68[e]	55.7	44	46

[a]Total capital requirement ($/kW).
[b]SubC = subcritical; SC = supercritical; USC = ultra-supercritical; CFB = circulating fluidized bed
[e]$/ton CO_2 transport, storage and monitoring is included and adds 4 mills/kWh to the LCOE
[d]COE Adder for CO_2 Transportation & Storage is 10.22 $/MWh
[f]Does not include costs associated with transportation and injection/storage.
[i,j]units are in kg/MWh and tonne/MWh respectively
[l]credits included for sulfur, NOx, SO_2, Hg and CO_2 are -0.03, 0.05, 0.07,0.03, 0.01 $/MWh respectively
[m]credits included for limestone, gypsum, NOx are 0.14, -0.04, 0.04 $/MWh respectively. Transportation and storage costs of 0.46 $/MWh are also included.
[g]credits included for limestone, gypsum, NOx, SO_2 are 0.14, -0.04, 0.04, 0.15 $/MWh respectively. Transportation and storage costs of 0.49 $/MWh are also included.

Pulverized Coal (PC) power plants are the most commonly used technology for power generation from coal. In a PC power plant, coal is pulverized and blown into a boiler where it is combusted with air to produce high pressure steam for power generation in a steam turbine. The flue gas from the boiler is typically passed through a heat exchanger to heat up the air going into the boiler, a desulfurization unit to remove SO_2, and, finally, a stack. The CO_2 capture at a PC plant has an amine capture unit that follows the desulfurization unit. The amine removes the CO_2 through a chemical reaction.

The pressure and temperature of the steam determine the relative efficiency of the power plant. Subcritical (SubC) plants produce steam pressure below 3200 psi and temperature below about 1025° F. Subcritical PC units have generating efficiencies between 33 and 37% (HHV).

Supercritical (SC) generating efficiencies range from 37 to 40% (HHV). Current state-of-the-art SC generation involves 3530 psi and 1050° F, resulting in a generating efficiency of above 38% (HHV) for Illinois #6 coal (MIT, 2007). A variation on SC combustion is oxy-combustion (OXY) in which coal is burned with oxygen instead of air which produces a flue gas of relatively pure CO_2 ready for capture, storage or direct use. Oxy-combustion can increase efficiency. The flue gas heat losses are reduced because the flue gas mass decreases as it leave the furnace and because there is less nitrogen to carry heat from the furnace.

Operating conditions above 1050° F are referred to as ultra-supercritical (USC). A number of ultra-supercritical units operating at pressures to 4640 psi and temperatures to 1112-1130° F have been constructed in Europe and Japan (MIT, 2007).

While not a traditional PC technology, circulating fluidized bed (CFB) power plants burn coal that is crushed rather than pulverized. CFBs are best suited for lower-rank, high ash coals such as lignite and some low-Btu sub-bituminous western coals.

For each study in Annexes A, B and C, two cases were analyzed: without capture and with capture. The following data is extracted from each study, for the two cases:

- Efficiency (E), defined on the higher heating value (HHV) basis.
- Heat rate, in Btu/kWh, defined on the higher heating value (HHV) basis.

- Total plant capital cost (TPC), in \$/kW;
- The fixed charge rate (FCF), in % per year;
- The capacity factor (CF) in %;
- The fuel price (FP), in \$ per million Btu, defined on the higher heating value (HHV) basis;
- Net power output, in MW;
- Quantity of CO_2 emitted, in lb/MWh;
- Levelised Cost of electricity (LCOE), in ¢/kWh, divided into:
  - LCOE due to capital investment ($LCOE_{CAP}$), in ¢/kWh;
  - LCOE due to fuel cost ($LCOE_{FUEL}$), in ¢/kWh;
  - LCOE due to operation and maintenance ($LCOE_{O\&M}$), in ¢/kWh;

The meanings of the other abbreviations are shown in the footnote of the table and in the notation section. The first two components of the cost of electricity can be calculated as follows:

$$LCOE_{CAP} = \frac{FCF \times TCP}{CF \times 24 \times 365} \frac{¢}{kWh} \quad (A.1)$$

$$LCOE_{FUEL} = \frac{3412 \times FP}{E \times 10^4} \frac{¢}{kWh} \quad (A.2)$$

$$COE_{O\&M} = LCOE - LCOE_{CAP} - COE_{FUEL} \quad (A.3)$$

The CO_2 avoided cost, expressed in \$ per tonne of CO_2 is reported in the tables with reference to the associated base plant using the same technology.

Annex B: Summary of IGCC Design Studies — As Reported

STUDY	MIT	MIT	Rubin	NETL	NETL	NETL	EPRI	EPRI	EPRI	EPRI	SFA
Technology[b]	GERQ[a]	GEQ	GEQ	GERQ	CoP	Shell	GERQ	GEQ	Shell	CoP	GEQ
Cost year basis	2005	2005	2005	2006	2006	2006	2006	2006	2006	2006	2006
Without Capture											
Net Power (MW)		538	538	640	623	636	630	600	620	612	
CO_2 emitted (lb/MWh)	832[i]	822[i]	822[i]	1,755	1,730	1,658	1,789	1,944	1,714	1,796	0.80[j]
Efficiency (%, HHV)	38.4	37.2	37.2	38.2	39.3	41.1					38.8
Heat rate (Btu/kWh)	8,891			8,922	8,681	8,304	8,832	9,600	8,466	8,870	8,807
TPC ($/kW)	1,430	1,567	1,567	1,813	1,733	1,977	2,190	1,894	2,234	1,938	1,842
FCF (% on TPC)	15.1	14.8	14.8	17.5	17.5	17.5	11.7	11.7	11.7	11.7	15
Fuel price ($/MMBtu)	1.5	1.2	1.2	1.8	1.8	1.8	1.5	1.5	1.5	1.5	1.53
Capacity Factor (%)	85	75	75	80	80	80	80	80	80	80	85
Electricity cost											
COE_{CAP} (¢/kWh)	2.90						3.75	3.24	3.83	3.32	3.71
$COE_{O\&M}$ (¢/kWh)	0.90						1.29	1.13	1.22	1.15	1.24
COE_{FUEL} (¢/kWh)	1.33						1.33	1.44	1.27	1.33	1.35
COE (¢/kWh)	5.13	5.55	5.55	7.80	7.53	8.05	6.36	5.81	6.31	5.80	6.33[l]
With Capture											
Net Power (MW)		493	493	556	518	517	552	523	500	515	
CO_2 emitted (lb/MWh)	102[i]	97[i]	97[i]	206	253	199	128	138	159	255	0.07[j]
Efficiency (%, HHV)	31.2	32.2	32.2	32.5	31.7	32.0					32.6
Heat rate, Btu/kWh	10,942			10,505	10,757	10,674	10,463	11,300	11,156	10,895	10,478
TPC($/kW)	1,890	2,076	2,076	2,390	2,431	2,668	2,732	2,410	3,267	2,670	2,313
FCF (% on TPC)	15.1	14.8	14.8	17.5	17.5	17.5	11.7	11.7	11.7	11.7	15
Fuel price ($/MMBtu)	1.5	1.2	1.2	1.8	1.8	1.8	1.5	1.5	1.5	1.5	1.53
Capacity Factor (%)	85	75	75	80	80	80	80	80	80	80	85
Electricity cost											
COE_{CAP} (¢/kWh)	3.83						4.68	4.13	5.60	4.57	4.66
$COE_{O\&M}$ (¢/kWh)	1.05						1.58	1.41	1.73	1.55	1.55
COE_{FUEL} (¢/kWh)	1.64						1.57	1.70	1.67	1.63	1.60
COE (¢/kWh)	6.52	7.19	7.19	10.29	10.57	11.04	8.74[d]	8.21[d]	9.00[d]	8.65[d]	8.29[l]
Comparison											
Avoid cost ($/tonne)	19.3[f]	22.6[f]	22.6[f]	32[e]	41[e]	42[e]	31.54	29.3	51.7	40.7	

[a]GE radiant cooled gasifier for non-capture case and GE full-quench gasifier for capture case. All other cases for capture and non-capture have the same gasifier.
[b]GEQ = GE Total Quench; GERQ = GE Radiant Quench; CoP = ConocoPhillips
[c]$/ton. CO_2 transport, storage and monitoring is included and adds 4 mills/kWh to the LCOE
[d]COE Adder for CO_2 Transportation & Storage is 9.08 $/MWh, 9.81 $/MWh, 9.58 $/MWh and 8.90 $/MWh for GERQ, GEQ, Shell and CoP respectively
[f]Does not include costs associated with transportation and injection/storage.
[g]CO_2 transport+storage cost is 7.1 $/tonne CO_2
[h]includes 0.56 ¢/kWh as a CO_2 disposal cost
[i,j,k]units are in kg/MWh, tonne/MWh and g/kWh respectively
[l]credits included for sulfur, NOx, SO_2 and Hg are -0.03, 0.04, 0.01,0.01 $/MWh respectively
[m]credits included for sulfur, NOx, SO_2 and Hg are -0.04, 0.05, 0.01,0.01 $/MWh respectively. Transportation and storage costs of 0.44 $/MWh are also included.

Integrated Gasification Combined Cycles (IGCC) is an emerging technology. In IGCC, coal is converted in a gasifier into synthesis gas (CO, CO_2 and H_2). Impurities are removed from the syngas before it is combusted. This results in lower emissions of SO_2, particulates and mercury. It also results in improved efficiency of capture compared to PC. Unlike post-combustion capture from PC plants, a water gas shift reactor is added, in which CO reacts with H_2O to form CO_2 and more H_2. Then a separation process, typically a physical absorption process, is used to remove the CO_2 from the "shifted syngas" stream. The CO_2 is then dehydrated for further compression, and the remaining gas stream of nearly pure H_2 is combusted in the gas turbine. Finally, waste heat is recovered to drive a steam turbine generator for additional power generation. A number of gasifier technologies have been developed. These include GE, Shell and ConocoPhillips (CoP). GE offers two designs: GE radiant (GERQ) and GE full-quench (GEQ). The GE and Shell gasifiers have significant commercial experience, whereas CoP technology has less commercial experience.

Annex C: Summary of NGCC Design Studies — As Reported

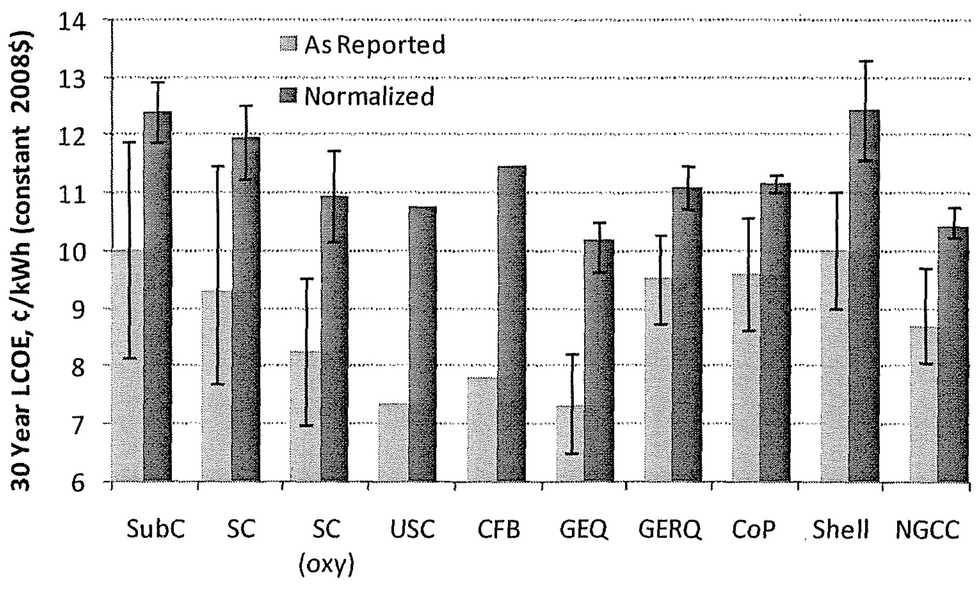
STUDY	Rubin	NETL	EPRI	SFA
Cost year basis	2005	2006	2006	2006
Without Capture				
Net Power (MW)	507	560	550	543.2
CO_2 emitted (lb/MWh)	367[i]	797	849	0.36[j]
Efficiency (%, HHV)	50.2	50.8		50.7
Heat rate (Btu/kWh)		6,719	7,306	6,726
TPC ($/kW)	671[a]	554	600	723
FCF (% on TPC)	14.8	16.4	11.7	15
Fuel price ($/MMBtu)	6[e]	6.75	6	6.35
Capacity Factor (%)	75	85	80	85
Electricity cost				
COE_{CAP} (¢/kWh)			0.96	1.46
$COE_{O\&M}$ (¢/kWh)			0.27	0.39
COE_{FUEL} (¢/kWh)			4.38	4.27
COE (¢/kWh)	6.03	6.84	5.61	6.13[l]
With Capture				
Net Power (MW)	432	482	467.5	482
CO_2 emitted (lb/MWh)	43[i]	93	100	0.06[j]
Efficiency (%, HHV)	42.8	43.7		45.0
Heat rate, Btu/kWh		7,813	8,595	7,581
TPC($/kW)	1091[a]	1,172	1027	1,266
FCF (% on TPC)	14.8	17.5	11.7	15
Fuel price ($/MMBtu)	6[e]	6.75	6	6.35
Capacity Factor (%)	75	85	80	
Electricity cost				
COE_{CAP} (¢/kWh)			1.64	2.55
$COE_{O\&M}$ (¢/kWh)			0.53	0.68
COE_{FUEL} (¢/kWh)			5.16	4.81
COE (¢/kWh)	8.06	9.74	7.87[d]	8.32[m]
Comparison				
Avoid cost ($/tonne)	62.6[f]	83[c]		73

All NGCC plant uses 2 x advanced F class turbines & HRSG
[a]Total capital requirement (TCR) in $/kW. For Rubin, TCR is assumed to add 12% to TPC.
[c]$/ton. CO_2 transport, storage and monitoring is included and adds 4 mills/kWh to the COE
[d]COE Adder for Carbon tax, CO_2 Transportation & Storage is 1.25 and 4.1 $/MWh respectively
[e]in $/GJ
[f]Does not include costs associated with transportation and injection/storage
[i,j]units are in kg/MWh and tonne/MWh respectively
[l]credits included for NOx is 0.01 $/MWh
[m]credits included for NOx is 0.01 $/MWh. Transportation and storage costs of 1.7 $/MWh is also included.

Natural Gas Combined Cycles (NGCC) has a higher thermal efficiency than PC and IGCC power plants and gas produces less CO_2 per unit of energy on combustion. As a result of these two factors it produces less CO_2 per MWh. Most new gas power plants in North America and Europe are of this type. In NGCC plant, natural gas is burned in a gas turbine with air to produce power. The waste heat of the flue gas from combustion is recovered in a heat recovery steam generator (HRSG) to drive a steam turbine generator for additional power generation. A post combustion capture plant will typically be an amine or ammonia absorption CO_2 removal unit that follows the heat recovery step. A gas-fed pre-combustion capture plant works in a manner analogous to an IGCC with syngas produced by a reformer rather than a gasifier.

Annex D: Standardizing the LCOE estimates

The comparison between the results of the LCOE calculations "as reported" and on the "normalised" basis described in the main text are shown in the chart below. Normalisation reduces variation in the estimates for each technology, as indicated by the smaller size of the error bars. However, normalised numbers still show some variation due to those factors not covered by the adjustment. The normalised cost of electricity is mostly greater than "as reported" since the costs were all escalated to the 2008 cost basis.



Annex E: Reported Capital Costs of Early IGCC Plants

The combined effects of scale and capture rate adjustment are shown in the table below, which is the source data for Figure 5 in Section 4 of the main text.

	Scale MW	Base Costs $/kW	Adjusted costs (460MW, 90% capture) $/kW
US, no capture	630	3750	6421
US, 50% capture	494	5000	6291
US 90% capture	275	7600	6590
Germany, 90% capture	330	6955	6343

Note: due to the lack of information in the published sources it has not been possible to adjust fully for the factors described in Section 2 of this paper. The small range of variation in the adjusted costs may to some extent be coincidental.

Annex F: Details of Modelling of Variation of Costs with Capture Rate and Scale

This Annex describes a model of variation of capture costs with capture rate. The model is stylised and as such it attempts to represent essential features of the situation while omitting much detail. However the main relationships are based on more detailed engineering studies and so the essential features of the conclusions are likely to prove robust.

Variation of capital costs with capture rate for IGCC

Work by GE has indicated that capital costs of an IGCC plant increase approximately linearly with capture rate. Work by GE and EPRI has also indicated that plant output and thermal efficiency decrease linearly with capture rate[27]. The effect of capture rates on costs of electricity has been modelled using these relationships.

[27] White (2008)

We define the relationships here as:

$$C(c) = K(1 + mc) \tag{F.1}$$
$$P(c) = W(1 - pc) \tag{F.2}$$
$$N(c) = E(1 - nc) \tag{F.3}$$

Where:

c is capture rate expressed as a fraction where $0 \leq c < 0.9$. A capture rate significantly greater than 90% is likely to be much more costly with existing technology, and so is not considered here as a practical option for early plant.

	Variable for IGCC <u>with or without</u> capture	**Value for IGCC <u>without</u> capture**	Positive constants representing the rates of change of each quantity with capture rate
Capital Cost in $	C	K	m
Plant Output in kW	P	W	p
Thermal Efficiency	N	E	n

From this the unit capital costs of the plant (U(c)) varies with capture according to:

$$U(c) = \frac{C(c)}{P(c)} \tag{F.4}$$
$$= \left(\frac{K}{W}\right)\left(\frac{1+mc}{1-pc}\right)$$
$$= \left(\frac{K}{W}\right)(1+mc)\left(1+pc+p^2c^2+p^3c^3 \ldots + p^n c^n\right)$$
$$= \left(\frac{K}{W}\right)\left(1+mc+pc+mpc^2+p^2c^2+\ldots\right)$$
$$= \left(\frac{K}{W}\right)I(c) \tag{F.5}$$

Where *I(c)* is a cost increase function represented by the infinite series in the brackets in the preceding equation.

Unit capital cost thus increases with capture rate *(dU(c)/dc* is unambiguously positive for all allowed values of *c)*. The increase is non-linear, with an increasing marginal cost of capture with capture rate ($d^2U(c)/dc^2$ is unambiguously positive for all allowed values of *c.)*

Variation of levelised cost of electricity with capture rate

Capital costs are the major component of levelised cost of electricity for an IGCC plant. We adopt a simplified treatment of levelised costs where the capital component is given by:

$$\frac{A.K}{W.H} \qquad (F.6)$$

Where:

A is an annuity factor, converting capital costs to an annual required capital recovery. It is assumed to take into account AFUDC, based on a fixed build profile.

H is annual hours of operation, assumed invariant with capture rate, so W.H annual output in MWh.

Variation of the capital component of levelised cost of electricity with capture rate is:

$$I(c)\left(\frac{A.K}{W.H}\right) \qquad (F.7)$$

We further assume that operating costs are a fraction (Q) of capital costs thus:

Operating costs = $Q.K$ *(F.8)*

Fuel cost increase has slightly different behaviour from capex. However the difference is relatively small and fuel costs are only a small proportion of the total, so assuming linearity of fuel costs with capital introduces only a small error.

Adopting this simplified treatment of levelised cost of electricity:

$$A.K + G.K + S.K = (A + Q + S)\frac{K}{W.H}$$

Gives

$$LCOE_c = I(c)(A + Q + S)\frac{K}{W.H} \qquad (F.9)$$

From this:

$$LCOE_c = I(c).LCOE_0 \qquad (F.10)$$

Cost of capture

The cost of capture at capture rate c is given by:

$$\begin{aligned} Capture\ Cost &= LCOE_c - LCOE_0 \\ &= LCOE_0(I(c) - 1) \end{aligned} \qquad (F.11)$$

Levelised cost of electricity and costs of capture thus shows the same form of increasing cost with capture rate as capital costs.

Cost of avoided emissions

Cost of avoided emissions is given by:

$$\frac{\left(COE_{with capture} - COE_{w/o\ capture}\right)\frac{\$}{MWh}}{\frac{\left(Q_{CO_2,w/o\ capture} - Q_{CO_2,with\ capture}\right)tonne}{MWh}} \qquad (F.12)$$

If the reference plant is the IGCC without capture the incremental cost of capture is given by the above expression for capture cost and avoided emissions are given by:

$$A(c) = F\left(\frac{1}{E} - \frac{1-c}{E-nc}\right)$$
$$= \left(\frac{F}{E}\right)c\left(1-\frac{m}{E}\right)\left(1-\left(\frac{m}{E}\right)c\right)^{-1} \qquad (F.13)$$

Where:

F is the specific emissions per kWh for the fuel.

Expanding this gives an expression of similar form to that for capital costs, where emissions avoided increase non-linearly with capture rate.

Combining expressions gives the cost of avoided emissions as:

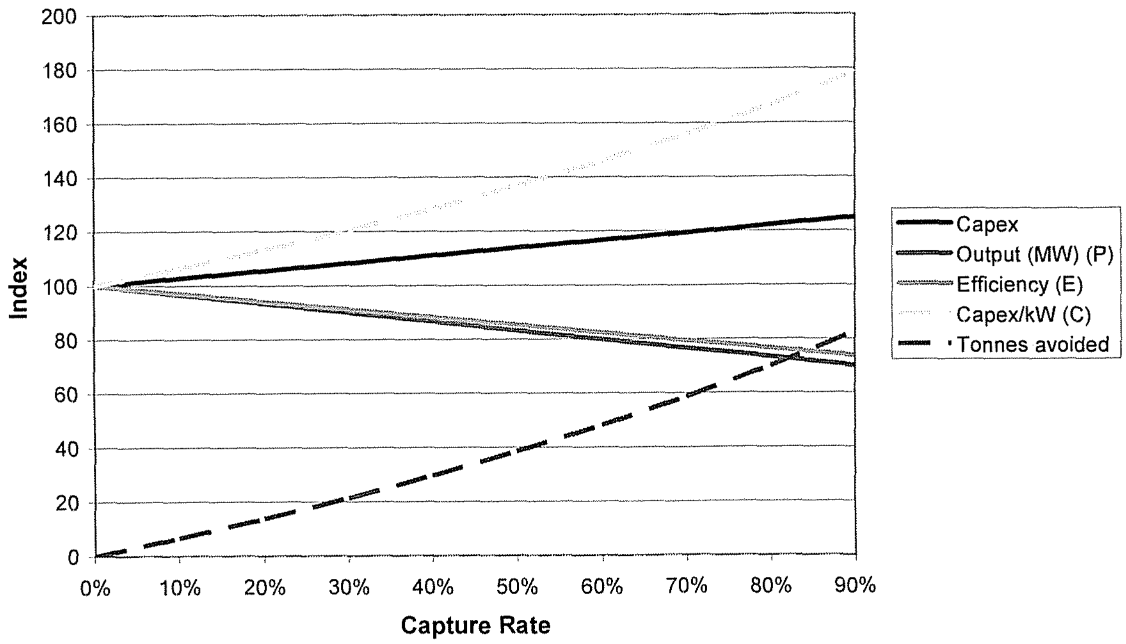
$$LCOE_0 \frac{(I(c)-1)}{A(c)} \qquad (F.14)$$

There is some evidence from the sources quoted that output falls less than linearly at higher capture rates. In that case the conclusion of no increase in unit costs with capture rate would be further supported.

The forms of these relationships are shown graphically in the following chart. The solid lines show the changes in capex output and efficiency defined in equations (F.1)-(F.3). The upper dashed line shows the unit capex derived from this, which increases non-linearly with capture rate as shown in the expression for U(c) derived above. Total LCOE (not shown) shows a similar trend.

Tonnes avoided increase with capture rate according to the trend shown by the lower dashed line. The cost per tonne avoided using an IGCC without capture is derived from the ratio between the increase in the top dashed line (where the increase represents additional costs of abatement) and the bottom dashed line (where the increase represents additional tonnes avoided).

Variation of costs and cost drivers with capture rate (illustrative)



A numerical example to illustrate the increase in tonnes avoided with capture rate is shown in the table below. CO_2 production at 0% capture converted to an index of 100 for clarity. The capture rates are shown for 0%, 45% to 90%. As efficiency decreases CO_2 production increases non-linearly (more than doubles on going from 45% to 90%). However this is more than offset by the increase in capture rates because at higher capture rates most of this additional CO_2 is captured. Consequently emissions avoided increases more than linearly with capture rate (decrease is greater from 45% to 90% than from 0% to 45%). A larger decrease in efficiency than is likely to be realised in practice is shown to illustrate the effect more clearly.

Capture rate	**0%**	**45%**	**90%**
Efficiency (%)	39.5	33.2	26.9
CO_2 before capture	100	119	147
Emissions after capture	100	65	15
Emissions avoided	0	35	85

Variation in costs with scale

Costs are estimated to fall by a certain percentage for each doubling of capacity. Costs (both capex and opex) vary in the form of:

$$K_n = K_0 x_n^{-b} \qquad (F.15)$$

Where:

$$b = -\frac{\log(1-r)}{\log(2)} \qquad (F.16)$$

in this case b = 0.28

a_n in the scale factor relative to the original unit
K_0 is the cost of the original non-scaled unit
r represents the average reduction in capital costs for a doubling of scale (17.5%)

Annex G: CO_2 Capture from Natural Gas Processing Plant

Of the cases reviewed, Case 3 includes lower CO_2 concentration in the flue gas (~2.8%), and thus the larger volume of gas to be handled resulting in larger equipment sizes and higher capital costs. The utility cost is also high, because of the power consumption, fresh water consumption, and the solvent loss.

In case 4, the flue gas from the thermal oxidizer, at 1100°F, needs to be first quenched to its adiabatic saturation temperature by water injection in a quench system. Saturated flue gas from the quench system then goes through the FGD absorber, where sulfur dioxide is removed by direct contact with an aqueous suspension of finely ground limestone. The chemical cost is high, because of the large volume of absorbents required. About two thirds of the cost is due to the use of limestone at the FGD and one third due to the use of caustic soda at the quench system. In addition to the high cost, case 4 may technically not be feasible for the following reasons:

- The oxidizer stack's flue gas contains ~ 3400 ppm of SOx, therefore ~ 100 ppm of SO_3 mist might form at the cooling step. Removal of SO_3 mist to 0.1 ppm level, which is what required before the flue gas passes to the CO_2 recovery process, might not be possible with currently available technology. High SO_3 mist also might cause severe corrosion problems.
- If oxidizer stack's flue gas contains hydrocarbon, the reaction between limestone and SOx may be hindered and SOx absorption efficiency may decrease.
- If oxidizer stack's flue gas contains sulfur or other particles, scaling problems are also expected.

In addition to the above, CO_2 recovery from flue gas presents challenges compared to CO_2 recovery from acid gases for the following reasons:

- Several emission sources compared to one single source as in case 5.

- Since flue gases contain 3-15% O_2, oxidative degradation can be significant. Acid gases do not contain O_2.

Capturing CO_2 from acid gases offers the following advantages compared with capture from the flue gases:

- The presence of H_2S in the CO_2 streams is beneficial to EOR since it increase miscibility; therefore the amount of H_2S that leaves the absorber with CO_2 can be adjusted to maintain effective miscible conditions in the reservoir. Flue gases do not contain H_2S.
- The H_2S concentration in the acid gas is 25 % H_2S. Using the typical selectivity of MDEA, this ratio can be increased to 37% with partial acid gas treatment - and the overall volume would be reduced by about 38%. This leads to an effective capacity increase of the sulfur recovery units resulting in significant acid gas flaring reduction during Testing and Inspections or increasing plant processing flexibility.
- CO_2 recovery from acid gas stream using Acid Gas Enrichment technology is more practical and economical option for the intended CO_2 recovery due to the maturity of this technology and the availability of the required CO_2 volume in one stream.
- Only partial treatment of the entire acid gas stream is required to provide the target CO_2 volume. (The full treatment will result in more CO_2 recovery with additional capital and operating cost).

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Date: 8 February 2010

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We have pioneered techniques and models that have become industry standards, including competitive market designs, efficient bidding mechanisms, and methodologies to assess market power.

Headquartered in Boston, the firm has offices throughout the United States, Canada, Europe, the Middle East, and Hong Kong. Charles River Associates is a registered trade name of CRA International, Inc.

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1. Summary

Charles River Associates (CRA) has conducted an analysis of the impact of the Cape Wind project on the ISO New England wholesale electricity market. Cape Wind, a 468 MW offshore wind power project planned for Nantucket Sound, is expected to provide enough power to supply approximately 10 percent of projected 2013 demand in Southeastern Massachusetts and just over 1 percent of total projected 2013 New England demand. This additional supply will reduce the need for generation from other power plants with higher pollutant emissions and operating costs, primarily fueled by natural gas, oil, and coal. CRA has projected wholesale power prices over the period 2013-2037, for scenarios with and without Cape Wind in service, and quantified the expected reduction in wholesale power prices and wholesale electricity costs that would result from the power supplied by the project.

The principal findings of the analysis are:

- **Adding Cape Wind would lead to a reduction in the wholesale cost of power averaging $185 million annually over the 2013-2037 time period, resulting in an aggregate savings of $4.6 billion over 25 years.**
- **With Cape Wind in service, over the 2013-2037 time period, the price of power in the New England wholesale market would be $1.22/MWh lower on average.**

2. Approach

In New England, electric power is bought and sold through a competitive wholesale market.[1] As a result of industry restructuring, New England utilities and other load serving entities own and operate almost no generating capacity, but rather make wholesale purchases from the competitive market, the costs of which are ultimately recovered through retail rates charged to end-use customers. Most New England customers pay a retail rate closely tied to prices set in periodic Standard Offer Service auctions, which in turn closely ties to expected wholesale power costs. Wholesale power costs are therefore a good measure of electricity costs for consumers in the New England Region. CRA has estimated the savings from Cape Wind by comparing wholesale power costs for the region with and without the project in service.

Introducing Cape Wind's additional supply into the competitive wholesale power market will lower prices by displacing higher cost generation. Power in New England is priced hourly,

[1] Power can be purchased through spot markets administered by ISO New England, or though bilateral transactions and forward electricity markets. The power sold from Cape Wind will affect prices in all of these markets, regardless of whether the output is sold under contract or through the spot markets. In fact, all generation, even if under contract, must be scheduled through the ISO New England spot markets. Power that is under contract for physical delivery is simply included at the bottom of the supply stack, therefore directly affecting the spot market. Likewise, expectations about prices in the spot market drive the pricing for forward transactions.

with the market price set by the offer from the highest-cost source of supply needed to meet demand. In each hour that the price is set by power plants with lower operating costs, rather than higher-cost units displaced by the supply from Cape Wind, the wholesale clearing price will be lower and electricity costs reduced. The variable operating cost of wind turbine generators is almost zero, so electricity from Cape Wind will be offered at the bottom of the regional supply stack in every hour it is available. Hence, Cape Wind will displace higher-cost generation and the associated greenhouse gas emissions in almost every hour of every year, resulting in a reduction in the market price. CRA has estimated these price decreases for each hour of each year from 2013 through 2037 and calculated the associated reduction in wholesale power costs.

The projections provided in this report cover the 2013 through 2037 time period and rely on the following key input assumptions:

- Natural gas and oil prices are based on the Energy Information Administration (EIA)[2] Annual Energy Outlook (AEO) 2009, as updated in April 2009 to account for the change in economic conditions in the prior six months.
- Federal greenhouse gas program in place with prices of $30/ton of carbon dioxide in 2013, escalating by 2030 to $60/ton, scenarios that are consistent with those presented in ExxonMobil's Outlook for Energy, A View to 2030.
- Electricity demand growth as projected by ISO New England in its most recent forecast, released in April of 2009.
- Inflation of 2.01 percent annually, based on the assumptions in the AEO 2009.

Additional detail about these assumptions is included in an appendix to this report.

CRA used the GE MAPS electricity market model to develop a fundamental forecast of market prices and generator dispatch for the New England Market. The GE MAPS model is a security-constrained dispatch model that simulates the chronological, hourly operation of an electricity market. The model takes the specified, cost-based bids for each generator in the market, along with other generating unit operating assumptions and performs a least-cost dispatch subject to limits on the flow of power across power lines and other elements of the transmission system. The model finds the least-cost dispatch of power plants and calculates hourly prices for electricity for each location within the New England market using the same basic approach that is applied in the actual operation of the power system and wholesale market.

CRA's analysis relied on forecasted production patterns that Cape Wind provided for the project. The production profile includes, for each month of the year, an average value for each hour of the day. In reality, there will be day-to-day fluctuations not captured in these patterns. Test data for the project site indicate that the hourly fluctuations during the summer

[2] EIA, an administration with the US Department of Energy, provides data and forecast for the energy sector. The AEO provides a comprehensive, long-term view on energy supply, demand, and prices, based on fundamental modeling of the markets for each energy commodity. The 2009 AEO is available at: http://www.eia.doe.gov/oiaf/archive/aeo09/index.html

months are coincident with warmer weather and higher electric demand. For example, due to the summer sea breeze effect, above average wind speeds have been recorded by Cape Wind's Scientific Data Tower on Horseshoe Shoal during eleven of the past twelve peak electric demand events in New England. Hence, CRA's estimates are likely to understate the potential benefits during summer peak hours.

3. Results

3.1. Wholesale Price Impact

Figure 2 shows CRA's estimates of difference in the average New England wholesale power prices with and without Cape Wind in service. Over the 25 years covered by the analysis, prices would be an average of $1.22/MWh lower with the project than without. As shown in Figure 3, the effect on wholesale electricity prices is even more pronounced for Southeastern Massachusetts, where the project will be interconnected with the New England grid. The average price reduction for that zone is $1.82/MWh.

Figure 1: Wholesale Price Reduction for New England

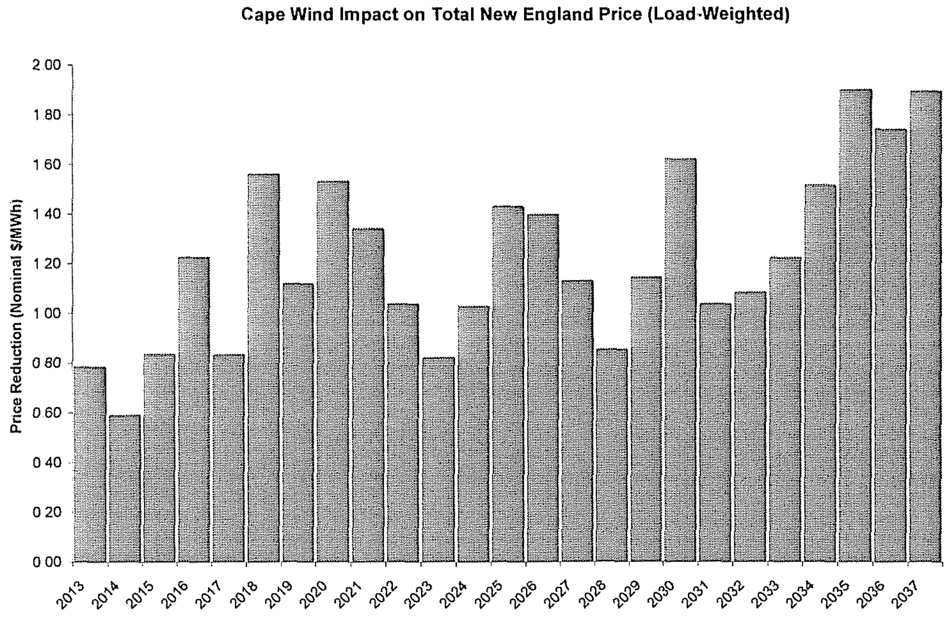
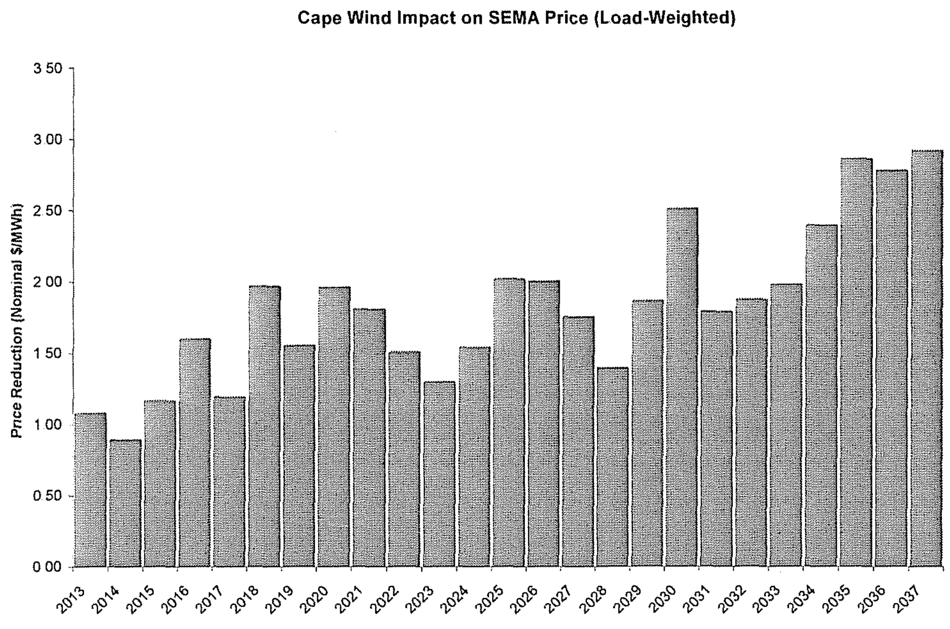


Figure 2: Wholesale Price Reduction for Southeastern Massachusetts

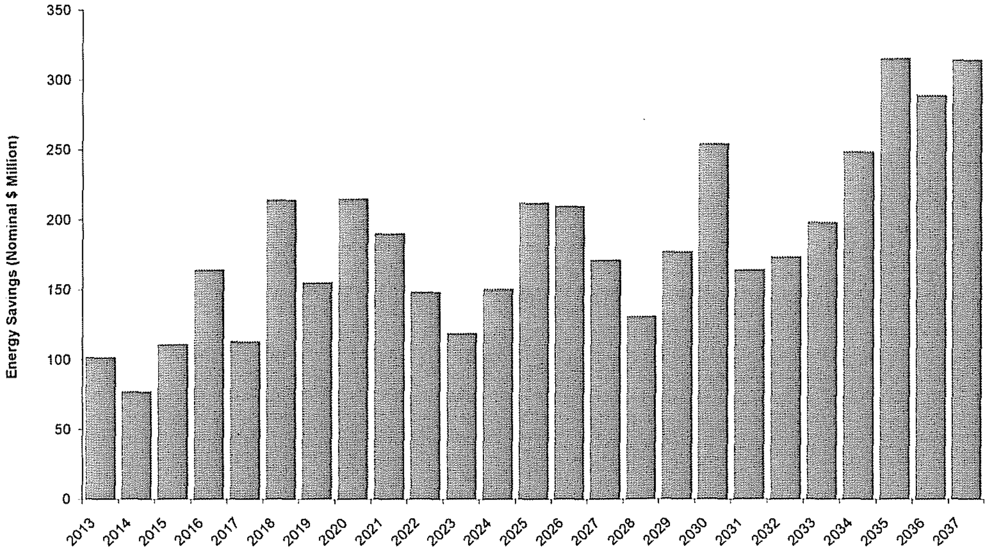


3.2. ESTIMATED SAVINGS IN ELECTRICITY COSTS

Figure 4 shows the expected savings in electricity costs associated with the forecasted reduction in wholesale market prices. The cost savings range between $77 million and $315 million annually, totaling $4.6 billion over the 25 year period. The savings fluctuate from year-to-year due primarily to the addition of new generating capacity added to meet regional demand growth. Because minimum efficient scale for new power plants is generally large, on the order of 500 MW, adding a new plant creates an initial surplus, which depresses the electricity price, and prices then rise as the surplus is absorbed by demand growth.[3]

[3] Additionally, the price impact and cost savings fluctuate from year-to-year based on the timing of forced outages for generating units, which are assigned randomly within CRA's model.

Figure 3: Projected Reduction in Wholesale Power Costs with Cape Wind in Service



3.3. CHANGE IN NEW ENGLAND GENERATION MIX

In order to illustrate how the Cape Wind project would change the generation mix for New England, Figure 5 shows the change in generation for non-wind resources for a representative year, 2015. As shown in Table 1, the expected pattern is very similar for other years. The output of Cape Wind will displace other generation from fossil fueled power plants, burning primarily gas, oil, and coal. Additionally, the pumped storage hydro facilities in New England would be utilized slightly more with Cape Wind in service, allowing some of the off-peak wind generation to be stored and used during peak periods. A small portion of the additional power from Cape Wind also displaces imports, or contributes to exports, for a reduction in total net imports to New England.

Figure 4: Change in Other New England Generation with Cape Wind in Service, 2015

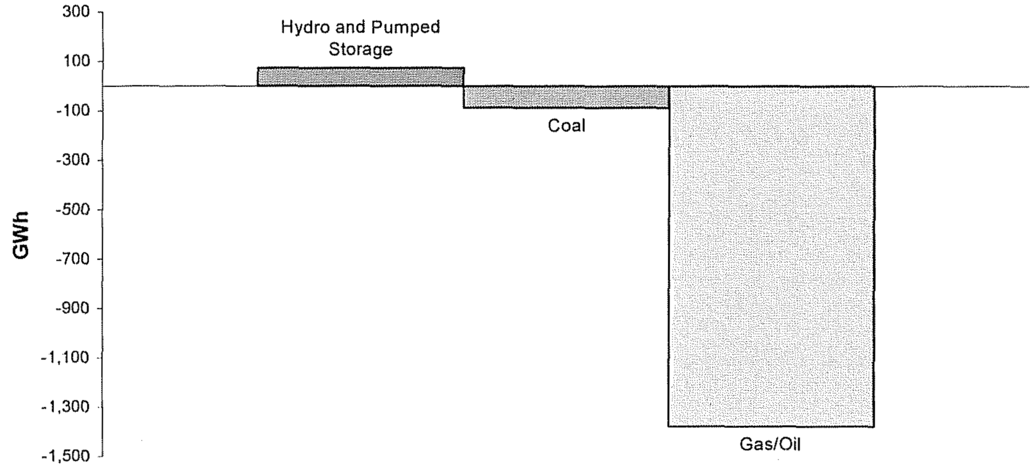


Table 1: Change in Non-Wind Generation by Fuel Type (GWh)

	2015	2020	2025	2030
Coal	(61)	(34)	(39)	(19)
Gas/Oil	(1,145)	(1,187)	(1,133)	(1,264)
Hydro	39	30	30	16
Demand Response	1	(4)	(5)	(10)

APPENDIX: KEY ASSUMPTIONS

A.1 FORECASTED DEMAND

- Demand and peak loads for 2013-2018 are based on the 2009 ISO-NE CELT report, the most recent regional forecast for New England.
- Beyond 2018, CRA escalated loads at the compound average growth rate for the 2013-2018 period (1.06%).
- ISO-NE projects hourly electricity demand by zone through 2018; these hourly demand forecasts were used in CRA's model runs, with the 2018 pattern used for all years thereafter, scaled appropriately to reflect demand growth.

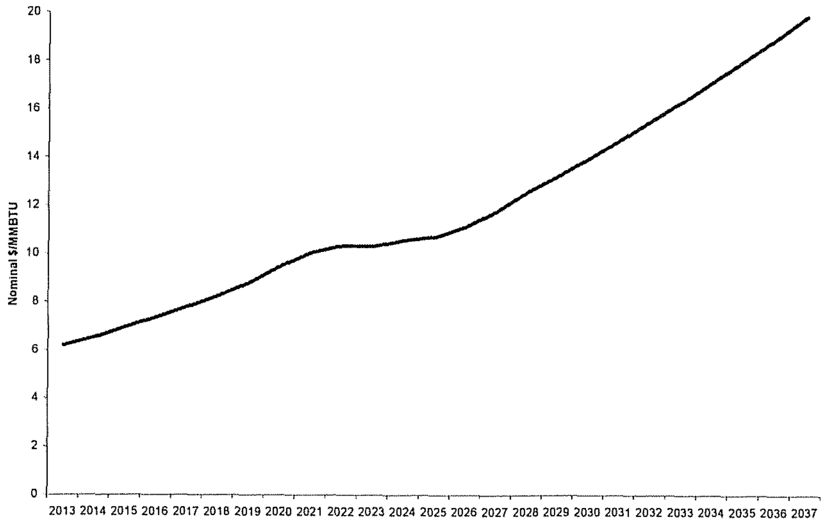
Table 2: Load Forecast

Year	2009 CELT Energy (GWh)	2009 CELT Peak (MW)
2009	131,315	27,875
2010	131,330	28,160
2011	132,350	28,575
2012	134,015	29,020
2013	134,635	29,365
2014	136,085	29,750
2015	137,540	30,115
2016	139,025	30,415
2017	140,565	30,695
2018	142,125	30,960
2019	143,672	31,289
2020	145,236	31,622
2021	146,818	31,958
2022	148,416	32,298
2023	150,032	32,642
2024	151,665	32,989
2025	153,316	33,340
2026	154,985	33,694
2027	156,673	34,052
2028	158,378	34,415
2029	160,102	34,781
2030	161,845	35,150
2031	163,607	35,524
2032	165,389	35,902
2033	167,189	36,284
2034	169,009	36,670
2035	170,849	37,060
2036	170,849	37,060
2037	170,849	37,060

A.2 FUEL PRICES AND CARBON POLICY

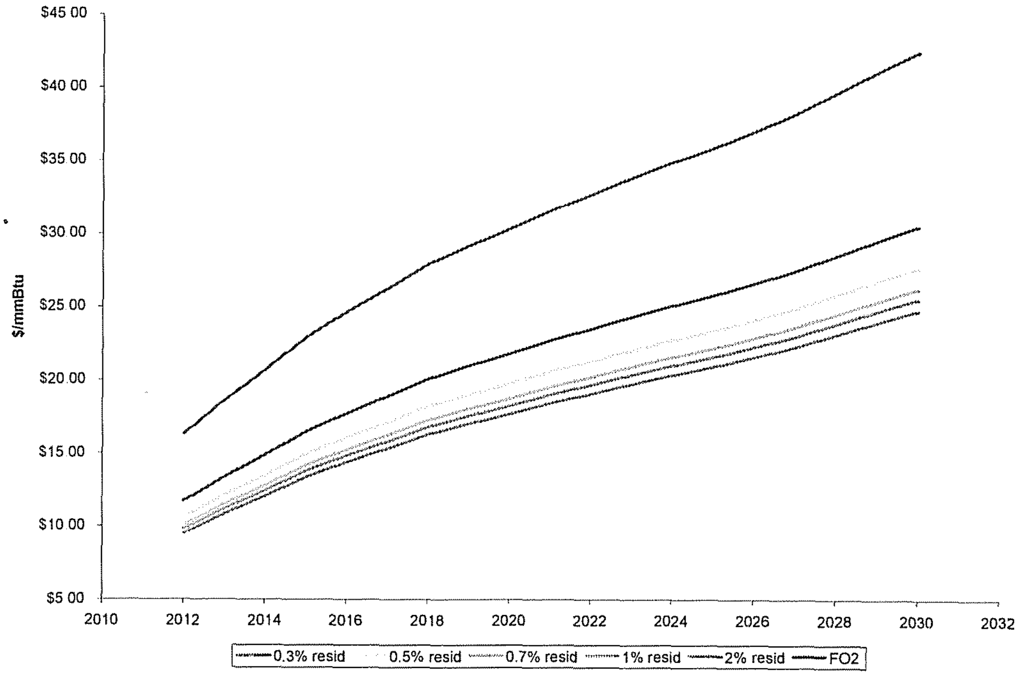
The gas forecast is based on the US EIA Annual Energy Outlook (AEO) 2009 forecast, released April 2009.

Figure 5: Henry Hub Natural Gas Prices (Nominal $/MMBtu)



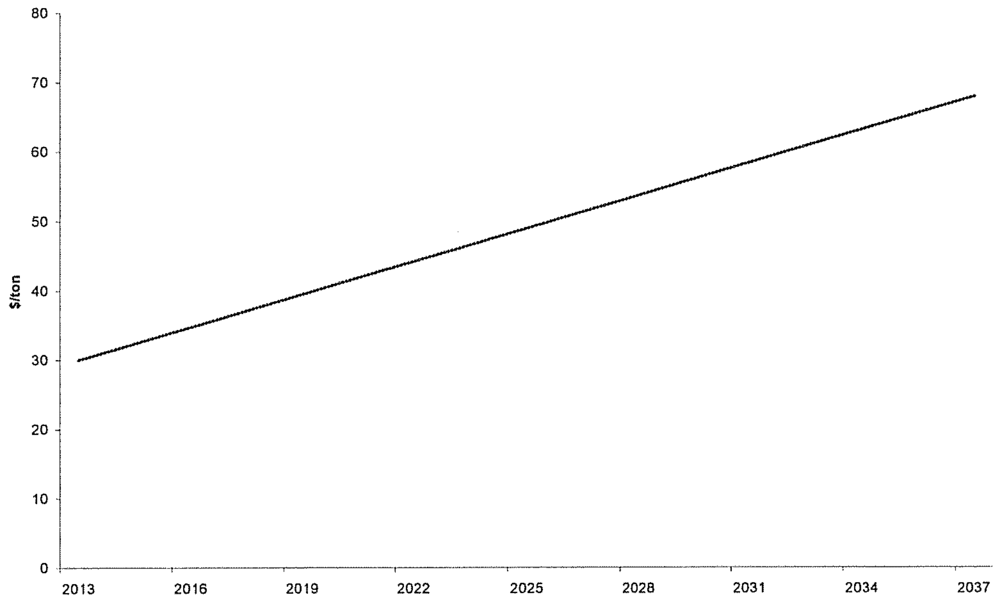
Oil prices are based on the April AEO2009 crude oil price forecast. CRA applied the most recent two-year Bloomberg historical relationships between crude and product prices to derive oil product prices from AEO2009 crude oil prices.

Figure 6: Oil Prices (Nominal $/MMBtu)



A federal carbon policy is assumed to be in place, resulting in costs of $30/ton in 2013 and escalating to $60/ton by 2030, consistent with scenarios presented in ExxonMobil's Outlook for Energy – A View to 2030. Beyond 2030, costs were assumed to escalate at the same average annual increase applied for the 2013 to 2030 period.

Figure 7: CO_2 Allowance Prices



A.3 Inflation Assumptions

All values in this report are in nominal dollars, assuming an average inflation rate of 2.01 percent. The assumption is based on the inflation rates applied in the AEO 2009, shown in Table 3.

Table 3: Inflation Rates

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
GDP Chain-type Price Index (2000=1.000)	1.237	1.243	1.258	1.274	1.297	1.324	1.354	1.385	1.417	1.450	1.484
Annual inflation rate	0.99%	0.55%	1.18%	1.25%	1.79%	2.12%	2.23%	2.29%	2.30%	2.37%	2.38%

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GDP Chain-type Price Index (2000=1.000)	1.521	1.560	1.600	1.638	1.675	1.711	1.746	1.782	1.820	1.858	1.896
Annual inflation rate	2.49%	2.55%	2.54%	2.39%	2.26%	2.12%	2.08%	2.07%	2.11%	2.08%	2.07%

Investing in Climate Change 2009

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Investing in Climate Change, One Year On

Kevin Parker
Member of the Group Executive Committee
Global Head of Asset Management

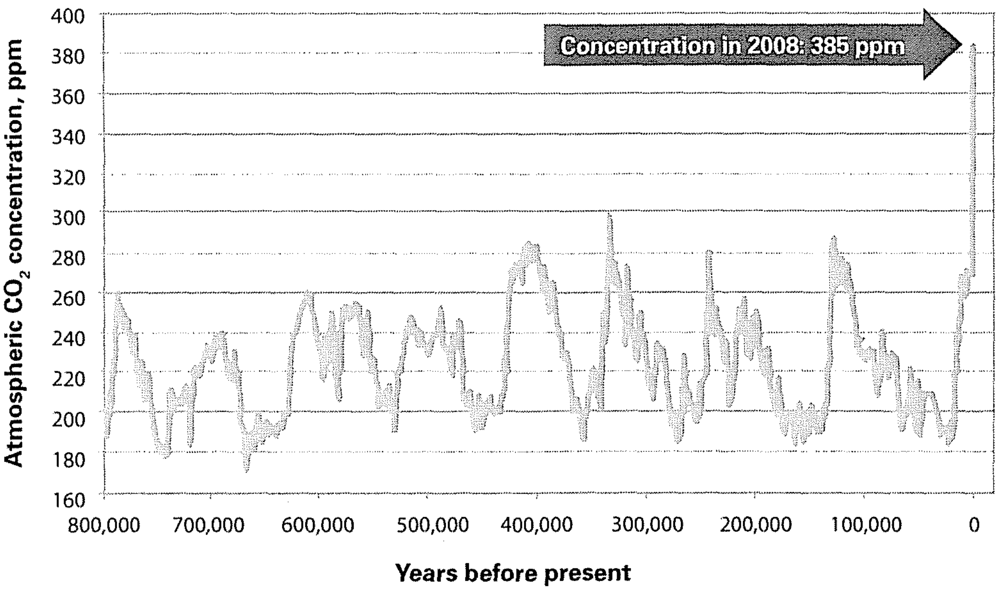
The necessity: Tackling carbon.

One year ago, we published *Investing in Climate Change: An Asset Management Perspective.* We argued that the growing investment opportunities in climate change were driven by long-term mega-trends that would continue into the foreseeable future.

One year on, the absolute necessity to act now to mitigate and adapt to climate change is even more urgent, and the opportunities generated by the sector continue to increase. New evidence has established that carbon in the atmosphere has reached an 800,000 year high (see graph below). The leading scientific research shows that we are careening towards the tipping point where average global temperatures are likely to rise by 2°C or more. Beyond 450 ppm CO_2e, it is increasingly likely that a series of macro-climatic shifts will set up a self-sustaining cycle of rapid global warming. Without significant and immediate action, or some unforeseen miracle, this tipping point stands no more than 15 to 20 years away.

The research in this report is driven by these two imperatives of necessity and opportunity. We have a new challenge, however, added to the mix: how to find the financing to develop and deploy the technologies we need to mitigate and adapt to climate change. Trillions of dollars have already been wiped off the global balance sheet by falling asset values, and the world's major economies are heading into recession. Investors understandably lack confidence at the moment and governments, who are dealing with the contingencies of the banking challenge, will be reluctant to commit further capital to the climate change sector for the foreseeable future.

Today's atmospheric CO_2 concentrations are higher than they have been for at least 800,000 years



Source: D. Lüthi, "High-resolution carbon dioxide concentration record 650,000-800,000 years before present," Nature, 15 May 2008.

Continued on next page.

Governments around the world can, however, take a big step in the right direction by agreeing to price the carbon externality. This would mean a global carbon tax in one form or another, such as cap-and-trade. The aim must be to create a clear long-term regulatory regime that determines a market-driven cost of carbon while at the same time encouraging the development of alternatives. If governments recognize the necessity of creating the right regulatory environment, investors will recognize the opportunity and step in.

There are numerous examples of governments already heading in the right direction. The recent renewal of the Production Tax Credit and Investment Tax Credit in the US assured solar and wind energy the regulatory certainty and proper incentives for continued development of the sector. And one need only look to Germany's Renewable Energy Sources Act for an example of true commitment to climate change mitigation. Germany has created a friendly environment for renewable energies to power up and connect to the grid through its system of feed-in tariffs and transparent and enforceable policies for renewable development. Any successful regulatory frameworks must have these clear, comprehensive procedures to incentivize industry and create capital formation over the longer term.

Achieving this kind of regulatory consistency on a global scale is a massive project, of course. But the world cannot wait. The potential economic, social and political upheavals that could result from a failure to tackle carbon emissions may be irrevocable. Severe though it is, the current financial crisis can eventually be fixed, and should not be used as an excuse for inaction.

Editorial

Mark Fulton
Global Head of Climate Change Investment Research

The opportunity: Low carbon prosperity.

As Kevin Parker points out in his opening letter, this is no time for governments to back away from climate change initiatives in the face of tough economic conditions. The necessity to encourage mitigation and adaptation remains urgent. For investors, this creates opportunity.

Constructing the right regulatory environment is a long-term goal for governments. Over the short-term, however, there is an economic slowdown to contend with. If governments are going to stimulate their economies, as many almost certainly will over the next year or two, they should support a climate-friendly approach. There are numerous reasons for doing this. Organization for Economic Co-Operation and Development politicians are talking a lot about energy security, which can be made climate-friendly when focused on renewables and clean coal technologies. Energy efficiency technologies are obviously highly desirable in economies facing recession. Infrastructure stimulus can be tied directly to climate-sensitive sectors such as power grids, water, buildings and public transport. Climate change industries, in fact, present a vast new field for the creation of new technologies and jobs. The current economic downturn presents governments with a historic opportunity to "climate proof" their economies as they upgrade infrastructure as a core response to the economic downturn.

This is just one of the reasons why we continue to expect a long-term secular growth trend in many climate change opportunities. In the energy sector alone, the International Energy Agency estimates that about $45 trillion will be needed to develop and deploy new, clean technologies between now and 2050. This represents nothing less than a low-carbon Industrial Revolution. Writers and policymakers from across the political and intellectual spectrum have recognized the potential this holds for long term job growth and industry creation. The debate around climate change is shifting away from cost and risk towards the question of how to capitalize on exciting opportunities.

Here again, the financial disruption of the last few months is a potential distraction. One consistent theme to emerge from the market turmoil is that there are no safe havens just now. Climate change, like almost all other asset classes, has not been spared from the broader market downturn. So where is the new investment capital going to come from?

We believe that for investors, climate change has a built-in advantage over most other sectors. Its regulated markets hold the promise of enormous secular growth. In the long-term, the earnings of companies and projects that are supported by governments for policy reasons are more trustworthy. There is, in short, a significant safety net effect here.

In the first part of our report, we determine that climate change is well-suited for public equity markets and particularly private markets such as venture capital, private equity, infrastructure and timberland. In the second part of our report, we examine some of the technical aspects of how regulation interacts with the underlying dynamics of technology costs and energy prices. This compendium provides an analytical framework that investors can use to understand the climate change opportunity.

Part I. Necessity and Opportunity in Turbulent Times

- **Climate change is a large and growing investment opportunity. There have been significant and meaningful developments since we published *Investing in Climate Change: An Asset Management Perspective* last year.**
- **Climate change sectors have been caught up in the volatility of the credit crisis. We believe that given their regulatory support, they should eventually recover well with value established in many sectors.**
- **We believe climate change when combined with energy security will play a role in government efforts to stimulate economies in 2009. We do not expect governments to back off the science and its implication for action, which remains a necessity.**
- **The opportunity suits most asset classes.**
- **Energy prices have been very volatile. In the long-term, we expect high oil and gas prices, weaker coal prices and we see carbon prices, as they are adopted, being the key backstop to ensuring clean energy is deployed.**

In this paper, we examine the climate change investment universe. This paper reviews the arguments we made last year in *Investing in Climate Change: An Asset Management Perspective*, and updates them, given the current market context. The components we examine in detail in this paper are:

II. What is new in climate change investing?

The investment opportunity in climate change has become broader, deeper, and more complex since we published *Investing in Climate Change: An Asset Management Perspective*. In the last year:

- Energy prices have experienced increased volatility;
- Some renewables have moved closer to commercial breakeven with conventional energy as their costs have come down;
- Some progress has been made negotiating the successor to the Kyoto Protocol;
- Emissions trading regimes such as the EU-ETS have been strengthened;
- Cap-and-trade is spreading to new geographies, such as New Zealand, Australia, and some US states (through the adoption of the Regional Greenhouse Gas Initiative);
- The climate change policy response in the US is gathering momentum;
- The climate change technology universe has grown leading to more opportunities for investors.

As a result, we have expanded some of the definitions in our Four Pillars of Climate Change Investment, and looked at developments in the past year in this context

- Government policy in climate change remains active. Government priorities, such as energy security and providing a "green collar" economic stimulus are contributing to the climate change debate;
- Carbon in Europe has been trading in the €20s, new regions are establishing cap-and-trade regimes or discussing them, and international negotiations are cautiously moving forward towards a global agreement to succeed Kyoto. Commodity prices – particularly energy prices – have become more prominent in discussions of climate change investing;
- Corporations have increased activity in climate change over the past year and the investment universe has expanded;
- Climate change technologies have developed and broadened.

The scientific debate over climate change

- One of the most important scientific announcements in our view was the updating of the ice core history, now dating back 800,000 years, depicting the extraordinarily high and previously unseen levels of carbon that we are now facing;
- We believe that the credible scientific debate is over. Indeed, as more dynamic models of climate change are developed, we expect to see estimates of the danger of global warming increase.

III. Low carbon prosperity

Low-carbon prosperity: an answer to the credit crisis and energy security?

- Over the course of the past few months, there has been more discussion of the potential for stimulus in climate change-related sectors to contribute to lifting the economy out of the current morass. We believe this is a significant opportunity;
- Energy security has also been a linked issue for policy makers in terms of long-term availability of energy and the economic implications of securing it.
- Energy efficiency is also a key way to deliver climate change mitigation with a long-term payback.

Political support for a "low-carbon Industrial Revolution"

- Policymakers across the political spectrum have also emphasized the potential for low-carbon prosperity;
- In the US, both Presidential candidates have talked about renewable energy in particular as a source of growth and job creation;
- The UK Prime Minister has stated that a low-carbon economy can be a new engine of productivity and economic growth;
- The German chancellor has argued that climate change can be a "win-win situation" if Germany invests in growing clean industries and creating new jobs;
- Chinese officials have underscored the importance of environmental protection in China's development;
- The Indian Prime Minister has said that sustainable development can go hand-in-hand with India's growth objectives.
- In the very long-term, the underlying climate change sectors have the potential to grow to very large scale – in the multi-trillion dollar energy, automotive and industrial markets.

IV. The credit crisis and climate change investing

The effect of the credit crisis on climate change investment sectors

- After generally outperforming in 2006 – September, 2007, listed equity climate change sectors lost ground against the market when the more pronounced credit crisis correction took hold from May 2008 onwards;
- In September 2008, many renewable stocks were aggressively sold off early in the month as liquidity considerations affected markets. Weaker energy prices led them lower as the regulatory support in the US for the Production Tax Credit (PTC) and the Investment Tax Credit (ITC) wavered in particular;
- The Troubled Asset Relief Act of 2008 (TARP) package in the US did extend solar and wind regulatory support, but for now markets are not focusing on fundamental support factors for company earnings;
- At a valuation level, the DWS climate change alpha pool P/E has only been marginally above the MSCI World, and is now looking more attractive following the correction;
- At a sector level, there have been signs of inflated valuations, with solar being the most noted example. That is now disappearing and the credit crisis correction looks to be delivering attractive valuations given strong regulatory support for earnings;

- From a credit supply perspective, which will affect public and private markets, certainly some companies and projects will find it difficult to raise debt capital, increasing reliance on equity and having to price for that. We believe that the more dependable regulatory environment for climate change will continue to see money move towards climate change sectors in private markets.

V. Investment attributes of climate change

Based on the key drivers in the climate change space, we have defined four broad sectors for climate change investment

- Clean Energy: (Power Generation, Infrastructure, Power Storage, Transport and Biofuels);
- Environmental Resource Management: (Water, Agriculture, Waste Management);
- Energy and Material Efficiency: (Advanced Materials, Building Efficiency, Power Grid Efficiency);
- Environmental Services: (Environmental Protection, Business Services);
- Combined, these sectors represent a fast-growing multi-hundred billion dollar marketplace, which offers numerous and compelling investment opportunities.

Investment Attributes

- We also looked at the arguments around whether climate change would persist over time or ultimately, simply become assimilated into markets. All Alpha factors will fade into the background eventually. Therefore, it becomes a question of how long the trend can last. Given the 40-50 year investment horizon and the size of the problem – $45 trillion of investment needed in energy markets alone – we believe that climate change will remain the source of identifiable Alpha for many years ahead;
- Key climate change sectors exhibit low-moderate correlation to the general economy;
- Listed equity markets have shown high correlation to the MSCI World Index, industrial companies and depending on the composition of the index, to small cap companies. While water and agriculture might be expected to show low correlation over the long term, more recently they have been caught up with the general market correction;
- One correlation that has attracted investor attention is renewable energy with oil prices. There is reason to expect renewables to track on the upside as rising oil prices make renewables more attractive on a breakeven analysis. On the downside, so long as regulatory support is there, renewables should outperform traditional energy sources in the long-term.

The investment attributes of climate change suit most asset classes:

- Venture capital, private equity, infrastructure and public equity;
- Hedge funds can create strategies across this space;
- The technology drivers of climate change are particularly suitable to venture capital (VC) and private equity (PE).

The effect of climate change sectors on asset classes and portfolios

- Looking at the investment attributes of climate change-related sectors, we can see that these are suited to the broad array of investment strategies. This includes listed equities, VC/PE for new technologies, and infrastructure for scaling up many areas of the climate change universe;
- As an example of how climate change affects portfolios, we have looked at the effect of an "efficient frontier" of including renewables, water and agriculture at different levels of asset allocation over the 2006-to-date timeframe. Given historic risk/return tradeoffs, the frontier shifts up by nearly 1% if 5% of funds are allocated into each of these sectors.

VI. Market sizing: Scarce resources and the size of the markets

A number of factors are acting together to create the climate change opportunity. Global population and GDP are rising fast

- The IEA calls for $45 trillion of investment in industry technologies by 2050;
- The growing global population and increasing wealth of that population will lead to significant increases in demand for water, food and energy;
- YTD 2008 VC/PE investment figures depict a continuously growing and healthy climate change sector;
- As a result, from a ~$150 billion market in 2007, investment across capital markets is projected to reach $650 billion p.a. over the next 20 years;
- All this has led to a deepening and broadening of the opportunities for investors.

VII. Carbon and energy prices

Global coal, oil and gas use – and their contributions to anthropogenic greenhouse gas emissions

- Three fossil fuels – coal, oil and gas – supply 88% of the world's primary energy and are responsible for about 60% of global greenhouse gas emissions. Consumption is set to rise as the world's population grows and wealth increases;
- Over the past 200 years, as the world has gone through a series of energy transitions, the most notable energy quality improvements have been made in volumetric density: there is more energy in a given volume of oil than there is in a given volume of coal or wood;
- Some aspects of energy quality have been harmed by the transitions in energy over the past 200 years, most notably spatial distribution, financial risk, risk to human health and amenability to mass storage;
- While improvements have been made in emissions intensity of energy (emissions per Joule) over the past 200 years, renewable energy is the final phase of reducing emission intensity towards zero;
- There are energy quality problems associated with renewables. Very large industries are expected to emerge to deal with problems associated with intermittency, gravimetric density, volumetric density and ease of transport of renewables. This will be a key area for investors as renewables grow to scale.

Developments in coal, oil and gas prices

- Fossil fuel prices have been trending up in the last few years, recently spiking but then collapsing;
- In the long-run (beyond 2015), oil prices are expected to return to above $90 a barrel (in real terms), gas prices are expected to return to at least $9/MMBtu (in real terms), and coal prices are expected to fall back to a $50-$75/ton range (in real terms);
- Coal prices in particular will have serious implications for greenhouse gas mitigation and carbon pricing.

The dynamic interrelationship of coal, oil gas and carbon

- Carbon price, the supply/demand balance of each of the three most important fossil fuels, and the scaling capacity of renewables are intricately linked in a dynamic relationship;
- Currently, the market has tended to correlate carbon prices in Europe with oil and gas prices, because carbon is used primarily to motivate fuel switching in the EU ETS. In the long-run, we do not expect that to hold, especially as coal becomes more plentiful;
- In the long-run, we expect coal prices to drop, while prices for oil, gas, electricity, road transport fuels and carbon rise. This is due to a complex interrelationship between key drivers of energy demand and supply: the growth of emerging markets, peak oil and a potential coal glut.
- In effect, carbon prices will become the crucial backstop for clean energy.

Part II. An Analytical Perspective

- **Government regulation, including carbon pricing, traditional regulation (mandates and subsidies) and innovation policy (incentives and subsidies) are major drivers of investment opportunities in climate change.**

- **We believe that carbon pricing, which prices the externality associated with greenhouse gas emissions, is the key long-term, market-related climate change policy.**

- **When it comes to assessing a specific project for investors, a set of complex variables comes into play at a granular level in a specific region and market context. Aggregate level analysis, while useful, needs to be articulated to a project-level.**

- **Clean technologies are becoming broader and deeper over time. It is important to understand their stage of development for investment purposes. For venture capitalists, driving costs down the learning curve is a key focus for any technology investment.**

- **In the long run, the most sustainable breakeven point for renewables is when they are commercially viable without subsidies, but with a carbon price regime as a de-risking backstop.**

In this paper, we develop an analytical framework for understanding the climate change opportunity. The components we examine in detail are:

- Government policy and regulation: an analytical framework;
- The investor perspective: risk and return around commercial breakeven;
- Clean technologies: deepening, broadening and developing.

II. Government policy and regulation: An analytic framework

Setting targets from the science

- The science is conclusive in our view. Atmospheric CO_2 concentrations are at an 800,000 year high and global temperatures are rising;
- The scientific evidence base – and the risks of not addressing climate change – have led to the establishment of mitigation targets. In order to avoid heightened probability of dangerous levels of warming, the IPCC estimates that long-run atmospheric concentrations of greenhouse gases should not exceed 450 ppm CO_2e, and annual emissions should be reduced by at least 50% from 1990 levels by 2050;
- Immediate action is important: the longer the world waits, the more difficult it will be to stabilize around 450 ppm CO_2e. The next few years are critical in establishing the stabilization path.

A map of climate change regulation – carbon pricing is the key in the long-term.

- As a starting point for analysis, the McKinsey-Vattenfall mitigation policy curve sets out the mitigation options for policymakers, along with their economic costs;
- Currently, governments use three broad sets of regulatory tools to address climate change:
  - Carbon pricing;
  - Traditional regulation (mandates and standards);
  - And innovation policy (incentives and subsidies).
- These three tools are used for different reasons. Carbon pricing is used to internalize the external costs of climate change, traditional regulation is used to correct for market failures and consumer behavior, and innovation policy is used to incentivize the development of expensive, but promising new technologies.

Optimal carbon pricing and policy of regulation

- Using carbon prices alone to incentivize the early development of emerging technologies – some of which could require carbon prices of nearly €100/ton to incentivize commercial development – may be inefficient, as such a high carbon price could put a disproportionate drag on the overall economy.
- Other regulatory instruments, such as R&D subsidies, can be used to drive innovation of what are currently more expensive opportunities such as CCS, allowing government to buy promising technologies down the learning curve without subjecting the entire economy to very high carbon prices.

Trends in climate change regulation and implications for investors

- Traditional regulation and innovation policy are currently the predominant policy tools in use, but we expect carbon pricing to become more dominant as time goes on;
- Understanding the existing regulatory framework on a geographical level, and how it interacts with local development priorities is essential to strategic asset allocation;
- The primary opportunities to generate tactical returns will happen when regulatory policies change due to scientific, political, or economic factors. An ability to predict these trends is obviously an alpha source.

From the policy curve to the commercial breakeven and investor opportunity

- While the greenhouse gas mitigation policy curve is a useful framework to consider from a policy perspective, it is not an investor opportunity curve;
- To get to an investor curve, taxes, specific project costs, regulatory support for clean technologies including incentives and subsidies would need to be included. Dynamic energy cost assumptions, specific regional costs and specific discount rates would also need to be considered to arrive at the investor curve.

III. The investor perspective: risk and return around commercial breakeven

Understanding commercial breakeven

- For a particular climate change technology to be adopted at scale, it must be commercially viable – breakeven or better against competitive, less environmentally-friendly options. We call this commercial breakeven.
- Over time, four factors have converged to drive the commercial breakeven of renewables:
    - Traditional and innovation-based incentives have been established.
    - Fossil fuel prices have increased;
    - Carbon prices are being introduced;
    - And the cost of renewables has declined as they have moved down the learning curve.
- There are different ways of calculating commercial breakeven, which can include or exclude subsidies,incentives and carbon prices. It is important for an investor to be aware of what is and is not included when assessing the economics of renewables;
- In the longrun, the most sustainable breakeven point for renewables is when they are commercially viable without subsidies, but with a carbon price regime as a de-risking backstop.

Using Levelized Cost of Energy (LCOE) as a tool for measuring investor opportunities

- LCOE is a framework that can be used to assess the economic viability of opportunities in the electricity markets;
- While the idea of LCOE is attractive at an industry level, adapting the framework to work as a project-level investor model is ultimately more useful. The investor opportunity model should take a number of factors into account:
- Most importantly, the discount rate should match the individual project risk profile and cost of capital, and local energy market dynamics need to be modeled;

- Scenario analysis on fuel prices, incentives and subsidies, and carbon pricing needs to be performed;
- The learning rate and other inputs need to be project-specific.

Using the investor's model to understand project risk and return

- As the investor model is developed for individual projects, a set of complex variables come into play at a granular level in a specific region and market context;
- There is a set of critical risk/return trade-offs investors need to take into account, specifically: operational, financial, regulatory, energy feedstock, learning rate, underlying electricity price and carbon. These risk-return trade-offs will be sources of alpha generation.

IV. Clean technologies: deepening, broadening and developing

Pacala and Socolow's wedges

- Pacala and Socolow developed a method for understanding climate change mitigation opportunities. In their research, they determined that there is no single technological solution to climate change;
- Instead, a variety of technologies will need to be deployed at scale to address the challenges of a warming planet.

The technology development process

- Each broad technological umbrella (e.g. solar) covers a broad array of subtechnologies. Each of these subtechnologies is at a different stage of commercialization, presenting different opportunities to investors;
- The technology development process takes a long time. As technologies move through the pipeline, the nature of the investment opportunity, as well as the risk/return profile, changes;
- In clean energy, there is significant room for improvements in existing technologies, as well as meaningful op portunities to develop and commercially deploy new, early-stage technologies such as CCS.

Investor implications

- New clean technologies have emerged over the past decade and technological advances in the clean technology space open up opportunities for investment in a range of new products and ideas;
- Understanding the characteristics of the subtechnologies moving through the pipeline is essential for investors;
- Deep knowledge of the technology development process, as well as a detailed overview of the technological landscape within each sector, is necessary to generate alpha in the space.

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CBO

The Economic Effects of Legislation to Reduce Greenhouse-Gas Emissions

September 2009

CONGRESSIONAL BUDGET OFFICE
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Global climate change poses one of the nation's most significant long-term policy challenges. Human activities are producing increasingly large quantities of greenhouse gases, especially CO_2. A strong consensus has developed in the expert community that, if allowed to continue unabated, the accumulation of greenhouse gases in the atmosphere will have extensive, highly uncertain, but potentially serious and costly impacts on regional climates throughout the world. Those impacts are expected to include widespread changes in the physical environment, changes in biological systems (including agriculture), and changes in the viability of some economic sectors. Moreover, the risk of abrupt and even catastrophic changes in climate cannot be ruled out.[1]

Those expected and possible harms may motivate policy actions to reduce the extent of climate change. However, the cost of doing so may be significant because it would entail substantial reductions in global emissions over the coming decades. U.S. emissions currently account for roughly 20 percent of global emissions. As a result, substantially reducing global emissions would probably entail large reductions in U.S. emissions as well as emissions in other countries. Achieving such reductions would probably involve transforming the U.S. economy from one that runs on CO_2-emitting fossil fuels to one that increasingly relies on nuclear and renewable fuels, accomplishing substantial improvements in energy efficiency, or implementing the large-scale capture and storage of CO_2 emissions.

One option for reducing emissions in a cost-effective manner is to establish a carefully designed cap-and-trade program. Under such a program, the government would set gradually tightening limits on emissions, issue rights (or allowances) consistent with those limits, and then let firms trade the allowances among themselves. Such a cap-and-trade program would lead to higher prices for energy from fossil fuels and for energy-intensive goods, which would in turn provide incentives for households and businesses to use less carbon-based energy and to develop energy sources that emit smaller amounts of CO_2.

Changes in the relative prices for energy and energy-intensive goods would also shift income among households at different points in the income distribution and across industries and regions of the country. Policymakers could counteract some but not all of those income shifts by authorizing the government to sell CO_2 emission allowances and using the revenues to compensate certain households or businesses, or to give allowances away to some households or businesses.

1. For additional information, see Congressional Budget Office, *Uncertainty in Analyzing Climate Change: Policy Implications* (January 2005).

This report makes the following key points:

- Climate change is an international problem. The economic impacts of climate change are extremely uncertain and will vary globally. Impacts in the United States over the next 100 years are most likely to be modestly negative in the absence of policies to reduce greenhouse gases, but there is a risk that they could be severe. Impacts are almost certain to be serious in at least some parts of the world.

- The economic impact of a policy to ameliorate that risk would depend importantly on the design of the policy. Decisions about whether to reduce greenhouse gases primarily through market-based systems (such as taxes or a cap-and-trade program) or primarily through traditional regulatory approaches that specify performance or technology standards would influence the total cost of reducing those emissions and the distribution of those costs in the economy. The cost of a policy to reduce greenhouse gases would also depend on the stringency of the policy; whether other countries also imposed similar policies; the amount of flexibility about when, where, and how emissions would be reduced; and the allocation of allowances if a cap-and-trade system was used.

- Reducing the risk of climate change would come at some cost to the economy. For example, the Congressional Budget Office (CBO) concludes that the cap-and-trade provisions of H.R. 2454, the American Clean Energy and Security Act of 2009 (ACESA), if implemented, would reduce gross domestic product (GDP) below what it would otherwise have been—by roughly ¼ percent to ¾ percent in 2020 and by between 1 percent and 3½ percent in 2050. By way of comparison, CBO projects that real (inflation-adjusted) GDP will be roughly two and a half times as large in 2050 as it is today, so those changes would be comparatively modest. In the models that CBO reviewed, the long-run cost to households would be smaller than the changes in GDP. Projected GDP impacts include declines in investment, which only gradually translate into reduced household consumption. Also, the effect on households' well-being of the reduction in output as measured by GDP (which reflects the market value of goods and services) would be offset in part by the effect of more time spent in nonmarket activities, such as childrearing, caring for the home, and leisure. Moreover, these measures of potential costs imposed by the policy do not include any benefits of averting climate change.

- Climate legislation would cause permanent shifts in production and employment away from industries focused on the production of carbon-based energy and energy-intensive goods and services and toward the production of alternative energy sources and less-energy-intensive goods and services. While those shifts were occurring, total employment would probably be reduced a little compared with what it would have been without a comparably stringent policy to reduce carbon emissions because labor markets would most likely not adjust as quickly as would the composition of demand for different outputs.

- CBO has estimated the loss in purchasing power that would result from the primary cap-and-trade program that would be established by the ACESA. CBO's measure reflects the higher prices that households would face as a result of the policy and the compensation that households would receive, primarily through the allocation of allowances or the proceeds from their sale. The loss in purchasing power would be modest and would rise over time as the cap became more stringent and larger amounts of resources were dedicated to cutting emissions, accounting for 0.2 percent of after-tax income in 2020 and 1.2 percent in 2050.

- The expected distribution of the loss in purchasing power across households depends importantly on policymakers' decisions about how to allocate the allowances. The allocation of allowances specified in H.R. 2454 would impose the largest loss in purchasing power on households near the middle of the income distribution. Which categories of households would ultimately benefit from the allocation of allowances is more uncertain in 2020 than in 2050. A large fraction of the allowances in 2020 would be distributed to households via private entities, and the distribution of the allowance value would depend on whether those entities passed the value on to customers, workers, or shareholders. In contrast, most of the value of allowances in 2050 would flow to households directly.

Aggregate Economic Impacts of Climate Change

Many of the natural changes that are likely to result from climate change (such as more frequent storms, hurricanes, and floods) will affect agriculture, forestry, and fishing; the demand for energy; and the nation's infrastructure. Despite the wide variety of projected impacts of climate change over the course of the 21st century, published estimates of the economic costs of direct impacts in the United States tend to be small.[2] Most of the economy involves activities that are not likely to be directly affected by changes in climate. Moreover, researchers generally expect the growth in the U.S. economy over the coming century to be concentrated in sectors—such as information technology and medical care—that are relatively insulated from climate effects. Damages are therefore likely to be a smaller share of the future economy than they would be if they occurred today.

As a consequence, a relatively pessimistic estimate for the loss in projected real gross domestic product is about 3 percent for warming of about 7° Fahrenheit (F) by 2100.[3] However, even for the levels of warming that have been examined, most of the estimates cover only a portion of the potential costs. Other costs in the United States could come from nonmarket impacts (which are not measured in GDP) and from the potential for abrupt changes:

2. For additional information, see Congressional Budget Office, *Potential Impacts of Climate Change in the United States* (May 2009).

3. See Dale W. Jorgenson and others, *U.S. Market Consequences of Global Climate Change* (Arlington, Va.: Pew Center on Global Climate Change, 2004), p. 36.

- *Nonmarket impacts.* Some types of impacts are very difficult to evaluate in monetary terms because they do not directly involve products that are traded in markets. Although such difficulties apply to effects on human health and quality of life, they are particularly significant for biological impacts, such as loss of species' habitat, biodiversity, and the various resources and processes that are supplied by natural ecosystems. Experts in such issues generally believe that those nonmarket impacts are much more likely to be negative than positive and could be large.

- *The potential for abrupt changes.* Experts believe that there is a small possibility that even relatively modest warming could trigger abrupt and unforeseen effects during the 21st century that could result in large economic costs in the United States. Two examples of such possible effects are shifts in ocean currents that could change weather patterns and affect agriculture over large areas, and rapid disintegration of ice sheets, which could dramatically raise sea levels around the world. The sources and nature of such abrupt changes, their likelihood, and their potential impacts remain very poorly understood.

The most comprehensive published study includes estimates of nonmarket damages as well as costs arising from the risk of catastrophic outcomes associated with about 11°F of warming by 2100.[4] That study projects a loss equivalent to about 5 percent of U.S. output and, because of substantially larger losses in a number of other countries, a loss of about 10 percent of global output.

The Effects of Policy Design Choices

The economic impact of any policy to reduce greenhouse-gas emissions would depend on a variety of policy and program design decisions that would be made by the Congress or the regulatory agencies that implemented such a policy. Most importantly, the economic impact would depend on whether the policy worked primarily through taxes on emissions, a cap-and-trade program for emissions, regulatory standards to reduce emissions, or a combination of those approaches. The economic impact would also depend on the stringency of the cap, whether other countries also adopted programs to reduce emissions, and other factors that would be specific to the approach chosen.

Approaches to Reducing Emissions

The most fundamental choice facing policymakers is whether to adopt conventional regulatory approaches, such as standards for energy-using machinery and equipment, or to employ market-based approaches, such as taxes on emissions or cap-and-trade programs. Market-based approaches, most experts conclude, would generally limit emissions at a lower cost than command-and-control regulations would. Whereas conventional regulatory approaches would impose specific requirements that might

4. William D. Nordhaus and Joseph Boyer, *Warming the World: Economic Models of Global Warming* (Cambridge, Mass.: MIT Press, 2000), pp. 95–96.

not be the least costly means of reducing emissions, market-based approaches would provide more latitude for firms and households to determine the most cost-effective means of accomplishing that goal.

A tax per unit of emissions would effectively fix the incremental cost of reducing emissions in any given period. Proposals for such taxes would generally specify rates that gradually increased year by year, with the aim of making activities that produced emissions increasingly expensive. A cap-and-trade system, by contrast, would explicitly restrict the annual quantity of emissions. Under such programs, allowances would be allocated or sold, and the trading of allowances would permit emissions reductions to be achieved in the lowest-cost manner. If caps increased in stringency over time, then the incremental costs of reducing emissions would rise as well.

If policymakers had full and accurate information about the cost of reducing emissions, taxes and caps could be equivalent: Policymakers could set a cap, and they would know what allowance price it would yield, or they could set a tax at that same allowance price and achieve the same reduction in emissions as under the cap. However, because policymakers face uncertainty, there is a crucial difference between the two approaches: A tax would leave the resulting amount of emissions uncertain, whereas a fixed cap would leave the resulting allowance price uncertain.

Most economists conclude that in the face of uncertainty about the cost of reducing emissions, a policy that set a year-by-year price path for greenhouse-gas emissions (such as a gradually increasing tax) would probably cost less overall than a policy that specified year-by-year emissions targets.[5] That conclusion is based on three observations:

- Climate change results from the accumulation of greenhouse gases in the atmosphere over many decades and centuries. As a result, reducing the potential risk of climate change would entail reducing cumulative emissions of greenhouse gases over multiple decades, but year-to-year fluctuations in emissions have little effect on the climate. By contrast, the economic cost of reducing emissions can vary a lot from year to year—depending on the weather, economic activity, and the prices of fossil fuels. A tax would motivate firms to cut their emissions more when the cost of doing so was relatively low and allow them to emit more when the cost of cutting emissions was high. A cap-and-trade program would offer firms less flexibility (although such a program could incorporate features, such as banking and borrowing of allowances, that would allow a degree of flexibility, as described below).

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5. For additional information on the difference between taxes and cap-and-trade programs, see Congressional Budget Office, *Policy Options for Reducing CO_2 Emissions* (February 2008).

- There is such great uncertainty about how a given quantity of emissions would ultimately affect global temperatures that there is very little additional certainty to be gained from choosing a fixed emissions goal (even one that is set over multiple decades) rather than a price path that is expected to achieve the same emissions goal—but that may exceed or may fall short of it depending on actual cost conditions. In essence, the additional certainty that a cap-and-trade program could provide about the amount of cumulative emissions would be bought at a relatively high cost without yielding corresponding certainty about the amount of climate change that would occur.

- The greater certainty about the price of emissions in the future that a tax would offer would provide affected firms and households with greater certainty about the conditions they would face in adjusting to restrictions than a cap would provide. That greater certainty would ease planning for capital investments and could lower the risk associated with developing new technologies.

Many proposals would augment basic cap-and-trade or tax provisions with subsidies for activities that reduced emissions or with regulations (such as standards for energy-using machinery and equipment). Some such approaches—subsidies for basic energy research, for example—would probably be useful and effective supplements to market-based approaches. Standards might also be the most effective regulatory approach in cases where market forces are unable to convey appropriate incentives, such as when a tax on energy would not provide an incentive for building owners to make efficiency improvements when renters are responsible for their electricity bills. Moreover, subsidies could help protect certain people or industries from the adverse economic effects of reducing emissions. However, to the extent that such additional elements supplanted the effective reliance on market forces to determine the lowest-cost means of reducing emissions, they might increase the overall economic costs of the program even though they might result in a lower allowance price in a cap-and-trade program.[6]

Government policy beyond research and standards directly tied to climate change would also indirectly affect the cost of restricting emissions. The tax treatment of investment could influence the cost and availability of particular technologies. Many experts believe that nuclear power could easily displace a significant amount of fossil fuel use, but only if the regulatory framework was adjusted to allow it. Similarly, existing land-use regulations and highway building might limit efforts to increase urban density and to foster the development of public transportation networks.

Cap-and-Trade Design Features

Many proposals for reducing emissions would include cap-and-trade systems to limit emissions of carbon dioxide and other greenhouse gases. Such systems raise numerous

6. Congressional Budget Office, *How Regulatory Standards Can Affect a Cap-and-Trade Program for Greenhouse Gases*, Issue Brief (September 16, 2009).

design issues. Four issues are especially important in considering the economic effects of a cap-and-trade system: the coverage and stringency of the cap, the degree of international coordination, flexibility in the timing of emissions reductions, and the allocation of emission allowances.

Coverage and Stringency. Under a cap-and-trade system, policymakers would face decisions about which emissions to control and when and how much to reduce them. Coverage could sharply affect costs: A given quantity of reductions in greenhouse-gas emissions could be achieved at a lower cost if the cap covered more types of gases and more sources of emissions. For example, although carbon dioxide emissions account for roughly 80 percent of greenhouse-gas emissions, some cuts in emissions of other greenhouse gases, such as methane or nitrous oxide, could be achieved at a relatively low cost. Likewise, even though research suggests that the bulk of reductions in CO_2 emissions would probably come from the electricity-generating sector, cost-effective reductions could also be found in other sectors, such as the transportation and residential sectors. Thus, a cap-and-trade program that covered as many types of greenhouse gases and sources of emissions as possible would be most likely to yield the most cost-effective reductions.

Most recent policy proposals would control nearly all CO_2 emissions from the burning of fossil fuels and would cover at least some emissions of non-CO_2 gases. In recognition of the difficulties in monitoring and measuring emissions, no proposal would include all types of emissions from all sources. Nevertheless, many proposals would provide incentives for sources of emissions that are not covered under the program to voluntarily participate. For example, landowners could earn credits by planting trees that absorb CO_2 from the atmosphere—credits that might then be sold to covered entities who would submit them in lieu of emission allowances. Some proposals would limit the use of such "offsets" to a fixed annual amount or a fixed fraction of total emissions. Greater latitude for such activities by uncovered sources could help moderate the costs of achieving a given emissions target because cheap reductions by uncovered sources could substitute for expensive reductions by covered ones. However, difficulties in ensuring the credibility and permanence of offsets could at least partially undermine their effectiveness in reducing overall costs.[7]

Cumulative U.S. greenhouse-gas emissions through 2050 are projected to total more than 300 billion metric tons of CO_2 equivalent (CO_2e). Recent legislative proposals vary in the magnitude of the reduction in cumulative emissions that they would require. Because requiring larger cuts in emissions would typically require deploying increasingly costly technologies, doubling the magnitude of the cuts required would be expected to more than double the cost of achieving them.

International Coordination. Climate change is an international problem that cannot be resolved without significant international cooperation and coordination. Emissions

7. For additional information, see Congressional Budget Office, *The Use of Offsets to Reduce Greenhouse Gases,* Issue Brief (August 3, 2009).

from anywhere in the world contribute to the global change in climate, so reducing emissions in any single country—even the United States—will do relatively little to avert climate change. Moreover, the stringency of foreign efforts to reduce emissions could strongly influence the cost of limiting them domestically. As long as a significant fraction of the world did not adopt similar policies, some of the reductions in the United States would probably be offset by increases in emissions elsewhere. For example, foreign consumption of oil would rise as declining domestic consumption pushed down international oil prices, and energy-intensive production overseas (and exports of such products to the United States) would most likely grow as domestic manufacturing costs rose relative to foreign costs. Such emissions "leakage" would lead countries that were controlling emissions to incur greater costs while achieving smaller reductions in global emissions.

Leakage could be avoided if most or all countries restricted emissions at the same time. Moreover, if a domestic cap-and-trade system was linked to similar systems in other countries, the United States might benefit from being able to buy low-cost foreign allowances—or it could find that prices for domestic allowances were driven up by foreign demand.

Flexibility in the Timing of Emissions Reductions. Offering firms subject to the cap flexibility as to when they made cuts in greenhouse gases—by including provisions that would require them to meet the annual caps only on average—could result in substantial cost savings while producing the same effect on the climate.[8] The ability to shift efforts to cut emissions over time could lower costs while achieving an equivalent reduction in warming because of the long-run nature of climate change.

Options for granting flexibility in the timing of emissions reductions fall into two categories. The first category would permit firms to transfer allowances across time. One important such provision would allow regulated entities to "bank" allowances in any given year for use many years after they were initially allocated. If, for example, reducing emissions this year proved less costly than expected, a firm might choose to do so and save some allowances for use in future years. A similar "borrowing" provision would allow firms to use allowances from future years (to be repaid with interest) during earlier periods when particularly high demand led to spikes in the cost of reducing emissions. A variant would create a "reserve pool" of allowances from future years that could be used in earlier years only under certain circumstances, such as when allowance prices rose above a threshold.

The second category of provisions would allow regulators to manage the price or quantity of allowances in a manner that induced a cost-effective time pattern of emissions reductions by specifying a path for allowance prices over time. For example, one such provision would allow annual caps to be exceeded if the market price for allow-

8. For additional information, see the statement of Douglas W. Elmendorf, Director, Congressional Budget Office, before the House Committee on Ways and Means, *Flexibility in the Timing of Emission Reductions Under a Cap-and-Trade Program* (March 26, 2009).

ances rose above some specified value (referred to as a "safety valve"). That value—typically specified to rise over time—would determine the maximum incremental cost in any given period. An alternative provision would set a ceiling and a floor—sometimes called a "price collar"—for the price of allowances.[9]

Allocation of Allowances. A key decision is how to distribute the value of the allowances. One option would be to have the government capture the value of the allowances by selling them, as it does with licenses to use the electromagnetic spectrum. Another possibility would be to give the allowances to energy producers, some energy users, or other entities at no charge. The European Union has used that approach in its cap-and-trade program for CO_2 emissions, and nearly all of the allowances issued under the 14-year-old U.S. cap-and-trade program for sulfur dioxide emissions are distributed in that way. Giving the allowances away to specific entities is equivalent to selling the allowances and giving the entities cash because those allowances could be sold in a liquid secondary market and thus could be easily converted into cash.

How policymakers decided to use the value of the allowances would affect the overall cost of a policy. For instance, the government could use the revenues from auctioning allowances to reduce existing taxes that tend to dampen economic activity. Some of the effects of a CO_2 cap would be similar to those of raising such taxes: The higher prices caused by the cap would reduce real wages and real returns on capital, which would be like raising marginal tax rates on those sources of income. Using the value of the allowances to reduce taxes could help mitigate the overall economic impact of a cap. Alternatively, policymakers could increase the cost of meeting the desired cap on emissions if they gave the allowances away in a manner that undermined the market incentives that the cap-and-trade program was intended to provide. For example, if electricity generators were given allowances on the basis of the amount of electricity that they produced with no further restrictions, they would be less likely to pass on the cost of meeting the cap to their customers in the form of higher prices. As a result, their customers would lack an incentive to find cost-effective ways to reduce their use of electricity. Moreover, as discussed below, decisions about how to allocate the allowances would have significant implications for the distribution of gains and losses among U.S. households.

The American Clean Energy and Security Act of 2009

H.R. 2454, the American Clean Energy and Security Act of 2009, as passed by the House of Representatives on June 26, 2009, would create two cap-and-trade programs for greenhouse-gas emissions—one applying to CO_2 and most other greenhouse gases, and a much smaller one for hydrofluorocarbons—and make a number of other significant changes in climate and energy policy. The cap-and-trade program

9. Ibid.; also see the statement of Douglas W. Elmendorf, Director, Congressional Budget Office, before the Senate Committee on Finance, *The Distribution of Revenues from a Cap-and-Trade Program for CO_2 Emissions* (May 7, 2009).

would restrict greenhouse-gas emissions from covered entities to 17 percent below 2005 levels by 2020 and 83 percent below 2005 levels by 2050.

In the main cap-and-trade program, covered entities would be phased into the program between 2012 and 2016. When the phase-in was complete, the cap would apply to entities that account for roughly 85 percent of total U.S. greenhouse-gas emissions. H.R. 2454 would not restrict the types of entities or individuals that could purchase, hold, exchange, or retire emission allowances in the main cap-and-trade program. An unlimited number of allowances could be banked for future use or sale, and a limited number of allowances could be borrowed from future allocations. A portion of each entity's compliance obligation could be met by purchasing offset credits from either domestic or international providers; in the aggregate, entities could use offset credits in lieu of reducing up to 2 billion tons of greenhouse-gas emissions annually, or more than half the emissions reductions projected around the middle of the policy period (roughly in 2030).

CBO estimates that the price of the allowances under H.R. 2454 would be $15 in 2012, the initial year that the cap took effect, and would rise at an annual real rate of 5.6 percent over the course of the policy, reaching $23 in 2020 and $118 by 2050 (all in 2007 dollars).[10] As a result of the price on emissions, the prices of goods and services throughout the economy would increase in rough proportion to the emissions associated with their production and consumption. At the same time, the allowances would become a source of income for the government or others. The government could capture the value of the allowances by selling them, or it could allow others to capture the value by giving them the allowances for free.

Key design features of H.R. 2454's cap-and-trade policy that influenced CBO's price estimate included:

- *Coverage and stringency.* CBO found that allowing firms to comply by purchasing offset credits (from both domestic and international providers) would reduce the allowance price by 70 percent.

- *Timing flexibility.* If covered entities were required to use all of their allowances in the designated year, then the price of the allowances would rise at a rate that was dictated by the speed at which the cap became more stringent. Banking helps to smooth out the price path—and compliance costs—over time. In CBO's projections, firms would bank allowances in the early years of the program, when the cap was relatively lenient, leading them to make more emissions reductions than neces-

10. For additional information, see Congressional Budget Office, cost estimate for H.R. 2454, the American Clean Energy and Security Act of 2009, as ordered reported by the House Committee on Energy and Commerce on May 21, 2009 (June 5, 2009). The costs in that estimate refer to federal budgetary costs and not the effects on the U.S. economy described in this report. The cost estimate reports allowance prices in nominal dollars. CBO estimates that the price of allowances in nominal dollars will rise from $16 in 2012 to $26 in 2019.

sary under the cap and pushing up the price of allowances. The accumulated supply of banked allowances would enable firms to meet their requirements under the cap in succeeding periods, helping to moderate allowance prices in later years. Firms would continue to bank allowances up to the point at which the rate of increase in the price of allowances was 5.6 percent, CBO's projection of the rate of return that they would make on alternative investments.

- *Allocation.* In general, the allocation of allowances in a cap-and-trade program would not affect the allowance price. An exception to that conclusion would occur if the allowances were allocated in a manner that would tend to undo the higher prices for energy-intensive goods and services that would result from the cap-and-trade program. CBO estimated that the allowance allocation in H.R. 2454 would have a small effect on the allowance price.

- *Standards and subsidies.* In general, the imposition of some regulatory standards and the provision of subsidies to develop new technologies would reduce the price of allowances to the extent that those standards or subsidies would change the source of emissions reductions from those that would have occurred with just the cap-and-trade program alone to others that would be motivated by the standard or subsidy. CBO estimated that the standards and subsidies in H.R. 2454 (including those for energy efficiency and for electricity generation that would capture and store CO_2) would lower the allowance price by roughly 10 percent. Most of that reduction would stem from the subsidy for carbon capture and storage. (However, reductions in allowance prices stemming from standards and subsidies could lead to higher, not lower, economywide costs because—to the extent that they generated changes in emissions patterns different from those that would arise from the cap-and-trade program alone—those reductions would not all be made in the most cost-effective manner.)

Economywide Effects of the Cap-and-Trade Provisions of the ACESA

By gradually increasing the prices of fossil fuels and other goods and services associated with greenhouse-gas emissions, climate legislation—including the cap-and-trade provisions of H.R. 2454—would tend to reduce long-run risks from climate change. Such legislation would also reduce economic activity through a number of different channels, although the total effect would be modest compared with expected future growth in the economy. The key channels are:

- Shift production, investment, and employment away from industries involved in the production of carbon-based energy and energy-intensive goods and services and toward industries involved in the development and production of alternative energy sources and non-energy-intensive goods and services;

- Reduce the productivity of existing capital and labor, which are currently geared to relatively inexpensive energy;

- Reduce domestic households' income, thus tending to reduce domestic saving;

- Discourage investment by increasing the costs of producing capital goods, which is a relatively energy-intensive process;

- Reduce net inflows of capital from abroad (because lower productivity and higher production costs for capital goods in the United States would make it more attractive for investors to invest in other countries);

- Reduce the total supply of labor by raising the prices of consumer goods and thus reducing workers' real wages; and

- Interact with the distortions of economic behavior imposed by the existing tax system.

Taken together, those changes would affect the levels and composition of gross domestic product and employment and would thus influence households' economic well-being.

Effects of Emissions Restrictions on Gross Domestic Product

Researchers often report the likely effect of climate policies on the economy in terms of their projected impact on GDP. On the basis of a review of estimates by other analysts, CBO concluded that climate legislation that would significantly reduce greenhouse-gas emissions in the United States would probably reduce GDP by a modest amount compared with what it would be without the legislation. The studies reviewed by CBO yielded a wide range of estimates of losses in GDP from climate policies, but all of them concluded that, all else being equal, higher prices for emission allowances would impose greater losses in GDP. On the basis of those studies, CBO concluded that GDP losses over the entire period of the policy were likely to fall

Table 1.

Projected Changes in Gross Domestic Product in Selected Years from the Implementation of H.R. 2454

Year	Percentage Change
2020	-0.2 to -0.7
2030	-0.4 to -1.1
2040	-0.7 to -2.0
2050	-1.1 to -3.4

Source: Congressional Budget Office based on its review of other studies.

in the range of 0.01 percent to 0.03 percent per dollar of allowance price.[11] CBO then estimated losses in GDP by combining its own estimates for the prices of allowances under H.R. 2454 with the range of predicted GDP losses per dollar of allowance price.

Using that approach, CBO concluded that the cap-and-trade provisions of H.R. 2454 would reduce the projected average annual rate of growth of GDP between 2010 and 2050 by 0.03 to 0.09 percentage points, resulting in progressively larger reductions in the level of GDP over time relative to what would otherwise occur (see Table 1). To place the size of those changes into perspective, CBO projects that real GDP in the United States will grow at an average annual rate of about 2.4 percent between now and 2050 and will be roughly two and a half times as large in 2050 as it is today.

11. In a 2003 review of studies of the potential impacts of the Kyoto Protocol, CBO concluded that GDP would be reduced by 0.018 percent to 0.028 percent per dollar of allowance price (measured in 2007 dollars) for each metric ton of CO_2 equivalent, depending on how the policy was implemented. See Mark Lasky, *The Economic Costs of Reducing Emissions of Greenhouse Gases: A Survey of Economic Models,* CBO Technical Paper 2003-3 (May 2003). A more recent review of estimates of the economic effects of H.R. 2454 and similar policies found that the predictions differ considerably for the short and medium term, mainly because the studies incorporate different assessments about the rates at which important markets can be expected to adjust in response to the new policies, but the long-term predictions agree much more closely. After 2030, point estimates of the percentage losses in GDP per dollar of allowance price yield average values similar to the range implied by the 2003 CBO analysis but suggest a wider range. (The high end of that range comes from a model that assumes that the supply of labor responds very sharply to changes in wages.) The studies that CBO reviewed include Environmental Protection Agency, Office of Atmospheric Programs, "EPA Analysis of the American Clean Energy and Security Act of 2009 H.R. 2454 in the 111th Congress" (June 23, 2009); Energy Information Administration, *Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007,* Report No. SR-OIAF/2008-1 (April 2008); Sergey Paltsev and others, *The Cost of Climate Policy in the United States* (Cambridge, Mass: MIT Joint Program on the Science and Policy of Global Change, April 2009); Warwick McKibbin and others, "Consequences of Cap and Trade" (fact sheet, Brookings Institution, 2009); and David Montgomery and others, *Impact on the Economy of the American Clean Energy and Security Act of 2009, H.R. 2454* (Washington, D.C.: CRA International, May 2009).

The uncertainty about the effects of H.R. 2454 on GDP is probably even greater than is expressed by that projected range of effects, even though the studies reflect a wide range of assumptions about possible future technological developments that might decrease the cost of reducing emissions, and about the degree to which people would adjust their decisions about working, saving, and investing in response to the legislation. All of the analyses that CBO reviewed characterize the economy in a very similar manner; none of them accounts for all of the possible economic effects of the legislation; and none explicitly addresses the uncertainty of its point estimates.

Unchecked increases in greenhouse-gas emissions would also probably reduce output over time, especially later in this century. Those climate-change-induced reductions in output would be moderated if actions that the United States took to reduce emissions were accompanied by similar efforts by other major emitting countries. Nonetheless, CBO concludes that the net effects on GDP of restricting emissions in the United States—combining the effects of diverting resources to reduce emissions and moderating losses in GDP by averting warming—are likely to be negative over the next few decades because most of the benefits from averting warming are expected to accrue in the second half of the 21st century and beyond.

Effects of Emissions Restrictions on Employment

By raising the prices of goods and services in proportion to the covered greenhouse-gas emissions associated with their production and consumption, climate legislation would affect the total level of employment as well as the distribution of employment among industries. Although supply-and-demand responses in many markets would influence the magnitude of industry-specific and total employment effects, a key consideration is how quickly and extensively labor markets would respond to sustained increases in energy prices. If businesses and workers treated each successive increase in energy prices as a surprise, then adjustment would be slow, and the policy would lead to slightly higher unemployment for some time. If, conversely, businesses and workers exercised foresight and acted in their self-interest, adjustment would occur more quickly, and the policy would have little effect on overall unemployment. In either case, a cap-and-trade program would have adverse effects on workers in specific industries and geographic areas; some provisions of H.R. 2454 are intended to ameliorate those effects.

Economywide Employment. The cap-and-trade program established by H.R. 2454 would probably have only a small effect on total employment in the long run, but changes induced by the program would still have costs for workers. The increases in the price of energy caused by the program would reduce workers' real wages. Total employment would be lower in the long run to the extent that some workers chose to work fewer hours or not at all—but for nearly all workers, the choice in the long run would probably be to remain in the workforce and accept the prevailing wage. Moreover, experience shows that, apart from recessionary periods, the dynamic U.S. economy provides jobs for most people who want to work.

Employment in Different Industries. The small effect on overall employment would mask a significant shift in the composition of employment over time. A cap-and-trade program for carbon dioxide emissions would reduce the number of jobs in industries that produce carbon-based energy, use energy intensively in their production processes, or produce products whose use involves energy consumption, because those industries would experience the greatest increases in costs and declines in sales. The industries that produce carbon-based energy—coal mining, oil and gas extraction, and petroleum refining—would probably suffer significant employment losses over time. Reductions also would be likely to occur in industries that use those forms of energy intensively or purchase emissions-intensive inputs to their production process from other industries, including chemicals, primary metals, minerals mining, nonmetallic mineral products, transportation, and construction. Among those industries, employment losses in chemicals and transportation services could be relatively large.

The shifts in demand caused by the policy would also create new employment opportunities in some industries. Businesses that produce the machinery necessary to generate energy without CO_2 emissions and that produce that energy—for example, electricity generated by the wind or the sun—would hire more workers. Employment would also probably increase in industry sectors that supply goods and services that use less energy in their production or that require consumers to purchase less energy when using the industry's product. In the automobile industry, for instance, employment would shift from producing vehicles that rely solely on internal-combustion engines fueled by gasoline to producing vehicles with hybrid or electric engines. The largest gains in employment would probably be in service industries.

The shift in employment between sectors of the economy would occur over a long period, as the cap on emissions became progressively more stringent and the allowance price (and, therefore, the price of emissions) became progressively higher. The experience of the U.S. economy over the last half-century in adjusting to a sustained decline in manufacturing employment provides evidence that the economy can absorb such long-term changes and maintain high levels of overall employment. From a peak of almost 20 million jobs in 1979, manufacturing employment fell to about 14 million jobs in 2007. Although manufacturing employment rose and fell with the business cycle over the period, the larger story is one of offsetting job creation and shifts of workers to other sectors of the economy. For example, from 2000 through 2007, employment in manufacturing fell by 3.5 million jobs, while nonmanufacturing private employment increased by 8.2 million jobs.[12]

12. For an analysis of the economy's adjustment to a declining demand for U.S. manufacturing, see Congressional Budget Office, *Factors Underlying the Decline in Manufacturing Employment Since 2000*, Issue Brief (December 2008).

Job turnover is always large in U.S. labor markets. In 2008, for example, employers reported that they hired about 56 million workers and that about 59 million workers left their jobs.[13] In reviewing several studies that addressed the aggregate employment effects of climate legislation, CBO found a wide range of implied estimates of annual workforce turnover—gross jobs created and gross jobs lost—and concluded that the annual churning in the workforce might range from hundreds of thousands of jobs to several million jobs depending on the year.[14] Even at the high end of that range, the churning of jobs that would be spurred by climate legislation would be small compared with what normally occurs.

The process of shifting employment can have substantial costs for the workers, families, and communities involved. For example, one-quarter of the workers who were displaced from their jobs in 2003—that is, workers who were permanently separated from their jobs because their employers closed or moved, there was insufficient work for them to do, or their positions were abolished—and who were subsequently reemployed were jobless for 27 weeks or more.[15] Finding a new job might require substantial worker flexibility. Some workers would need to migrate to new geographic areas. An earlier study indicated that in states whose industries were hit by significant adverse shocks between 1950 and 1990, the rate of unemployment generally decreased only when workers moved to different states, a process that often took more than five years to unfold.[16] And some workers might need to acquire new skills more suited to the employment opportunities available to them.

Moreover, some workers would never find the new employment they were seeking. Some might end up working fewer hours than they might prefer. And some might leave the labor force entirely. Almost half of the unemployment spells completed in 2003 ended with the individuals leaving the labor force rather than becoming

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13. See Department of Labor, Bureau of Labor Statistics, *Job Openings and Labor Turnover: January 2009*, USDL 09-0245 (March 10, 2009), Tables 11 to 14.

14. CBO reviewed a number of studies that addressed the effects of policies like those that H.R. 2454 would put in place, including David Kreutzer and others, *The Economic Consequences of Waxman-Markey: An Analysis of the American Clean Energy and Security Act of 2009*, CDA09-04 (Washington, D.C.: The Heritage Foundation, August 5, 2009); McKibbin and others, "Consequences of Cap and Trade"; Environmental Protection Agency, Office of Atmospheric Programs, "EPA Analysis of the American Clean Energy and Security Act of 2009 H.R. 2454 in the 111th Congress"; Montgomery and others, *Impact on the Economy of the American Clean Energy and Security Act of 2009 (H.R. 2454)*; Energy Information Administration, *Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007;* Paltsev and others, *The Cost of Climate Policy in the United States;* and Mun S. Ho, Richard Morgenstern, and Jhih-Shyang Shih, *Impact of Carbon Price Policies on U.S. Industry*, Discussion Paper 08-37 (Washington, D.C.: Resources for the Future, November 2008).

15. Data for people who lost jobs in 2003 are from Congressional Budget Office, *Long-Term Unemployment* (October 2007), p. 11.

16. Oliver Jean Blanchard and Lawrence F. Katz, "Regional Evolutions," *Brookings Papers on Economic Activity*, no. 1 (1992).

employed.[17] Women, less-educated workers, and older workers who lose their jobs appear to be more likely to leave the labor force than men, more-educated workers, and younger workers who lose their jobs.[18] Some workers leaving the labor force, especially older or less-educated workers, might opt to seek disability payments that they would not have claimed otherwise.

Even workers who find new jobs might suffer permanent adverse effects. For example, reductions in employment that occur rapidly in particular geographic areas or industries could lead to significant reductions in the lifetime earnings of some affected workers. Even 15 to 20 years later, men who separated from their stable jobs in a mass layoff during the 1982 recession had annual earnings that were 20 percent lower than similar workers who did not experience such a job loss.[19]

Provisions of H.R. 2454 Intended to Ameliorate Those Employment Effects. Some provisions of the bill—those that would subsidize the development and deployment of technologies that reduced emissions or that would subsidize production by specific industries and firms—would dampen the effects of the policy on employment in industries and areas where they are expected to be most severe.

- Selected provisions of the bill would subsidize petroleum refiners through 2026 and trade-exposed, energy-intensive industries—those in which domestic firms compete with foreign firms that do not bear the cost of complying with comparable policies to control emissions—through 2035. Those subsidies would be linked to output, causing the firms receiving them to produce more than they otherwise would under the cap-and-trade system and in doing so employ more people (although that process also dampens the reallocation of output and employment to industries that produce fewer carbon emissions).

- The bill also includes measures that would decrease the negative effects of the cap-and-trade system on output and employment in the coal mining and processing industries. Those provisions would establish and provide funding for the Carbon Storage Research Corporation. That entity would, in the 15 years after enactment of the bill, support the development of technologies to capture and store carbon, potentially enabling coal-fired plants to generate electricity without releasing greenhouse gases into the atmosphere. Through 2050, utilities or merchant generators that invested in and operated plants that used those technologies to generate electricity would be paid subsidies to offset the higher costs of that technology.

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17. See Randy Ilg, "Analyzing CPS Data Using Gross Flows," *Monthly Labor Review* (September 2005), pp. 10–18.

18. Henry Farber, "What Do We Know About Job Loss in the United States? Evidence from the Displaced Workers Survey, 1984-2004," *Economic Perspectives* (2005), pp. 13-28.

19. Till von Wachter, Jae Song, and Joyce Manchester, *Long-Term Earnings Losses Due to Mass Layoffs During the 1982 Recession: An Analysis Using U.S. Administrative Data from 1974 to 2004* (April 2009), www.columbia.edu/~vw2112/papers/mass_layoffs_1982.pdf.

Those subsidies would increase demand for coal and boost output and employment in the coal industry relative to what would occur under the emissions restrictions in the legislation but without those subsidies.

- The bill also would establish the Climate Change Worker Adjustment Assistance program and provide funding of $4.1 billion through 2019 for that program. That program would aim to cushion the effects of the emissions-control policies on workers who lost their job as a consequence of the policy. It also would seek to complement the flexibility evident in U.S. labor markets by providing job training and assisting workers searching for employment.

The Overall Burden on Households

Households' well-being depends on the amount and composition of goods and services they consume as well as how much time they have for nonmarket household activities including leisure. Policies to restrict emissions could affect all elements of households' well-being, and the legislation's overall burden would be determined by the value that people place on those various elements. For example, if people found products and activities that were not greenhouse-gas-intensive to be good substitutes for ones that were, they would be more willing to switch between them. As a result, they would find rising prices for greenhouse-gas-intensive products and activities less burdensome than if there were no good substitutes for them.

Some of those components of well-being—mainly the consumption of marketed goods and services—are included in GDP, but other components are not. Conversely, some components of GDP, such as exports and investment, do not directly affect households' well-being in the same way that consumption does, although they support jobs and provide for the future. A substantial proportion of projected GDP impacts are due to declines in investment, mainly from the increased costs of producing energy-intensive capital goods. Declines in investment translate only gradually into reduced household consumption. As another example, if the policies caused output and real wages to fall, the burden of lower consumption might be partly offset if people also chose to supply less labor and instead devoted more time to valuable nonpaid activities not included in GDP, such as childrearing, production within the home, and leisure activities.

Measuring the overall burden of policies like those embodied in H.R. 2454 requires estimates not only of supply and demand responses in many markets but also of households' valuation of activities that take place outside markets. Such estimates are difficult to obtain and very uncertain. Only two of the analyses of H.R. 2454 reviewed by CBO provide estimates of the overall burden, and the results differ considerably, reflecting differences in assumptions about households' behavior.[20] On the basis of those estimates and of estimates of the burden of other types of policies such as tax shifts and trade liberalization, CBO concludes that the overall burden of H.R. 2454 is likely to be smaller than the projected loss in GDP.

CBO developed an estimate of households' loss in purchasing power as a rough indication of the direct effect that the cap-and-trade program established in H.R. 2454 would have on households. That loss in purchasing power equals the costs of complying with the policy minus the compensation that would be received as a result of the policy.[21] Compliance costs include the cost of purchasing allowances and offsets, and of reducing emissions—costs that businesses would generally pass along to households in the form of higher prices. Compensation includes the free allocation of allowances, receipt of proceeds from the sale of allowances, and profits earned from producing offsets; much of that compensation would be passed to households from businesses and governments.

Although CBO's measure of the loss in purchasing power provides an estimate of the direct effect of the cap-and-trade program on households, it ignores some channels of influence on economic activity and households' well-being that cannot be readily quantified. Some of the omitted channels lead CBO's measure to overstate households' true burden, and some lead CBO's measure to understate the burden. The latest research in this area does not reach a clear conclusion about the relative magnitude of those channels, but it appears that CBO's measure of the loss in purchasing power probably understates to a small degree the true burden of the cap-and-trade program.

On the one hand, in keeping with the standard procedures followed by CBO, the Office of Management and Budget, and the Congressional Budget Committees in identifying federal budgetary costs, CBO estimated the price path for allowances that

20. Some models—including one that provides an estimate of the burden—assume that households are very willing to work less and to shift their consumption away from goods and services that become relatively more expensive. Such models conclude that cap-and-trade policies to reduce carbon dioxide emissions would have a larger effect on GDP (because households would provide less labor to produce goods and services and would save less as well) but would impose only a small overall burden (because households could easily substitute relatively cheaper goods and services for more expensive ones and substitute household production or leisure for work). Much empirical work suggests that the supply of labor is significantly less flexible than those models assume, and CBO's own models and analyses in other areas generally assume less flexibility. By contrast, models that assume that households are relatively inflexible about shifting their consumption of goods, services, and leisure generally (including the other model in CBO's review that provides an estimate of the burden) conclude that policies would have smaller effects on GDP but larger effects on the overall burden (although still somewhat smaller than the GDP effects). Those estimates of the burden do not include any value people place on averting climate change by reducing emissions.

21. Once the compensation received by U.S. households is deducted from the compliance costs, the remaining loss in purchasing power stems from the cost of reducing emissions and producing domestic offsets, expenditures on international offsets, and the value of allowances that would be directed overseas.

would reduce emissions to the levels defined by the annual caps without accounting for the effect that the policy might have on GDP. Because the program would reduce GDP (and thus lessen the overall demand for energy), the allowance price required to meet the cap would be slightly lower than CBO's estimate. A lower allowance price, in turn, would lead to a smaller loss in purchasing power. CBO's estimate of the loss in purchasing power, therefore, is slightly larger than would be the case if the agency had accounted for the potential decline in GDP when it estimated the price of allowances. In addition, CBO's measure ignores ways in which the program might interact with distortions of economic behavior (and, thus, costs ultimately imposed on households) generated by the existing tax system. Some of those interactions would tend to reduce overall economic costs. For example, the existing incentive for overconsumption of housing from the mortgage interest deduction might be countered to some extent by higher energy prices, as housing is energy intensive.

On the other hand, CBO's estimate of the loss of purchasing power does not capture all of the ways in which the cap-and-trade program could impose costs on households. There would be transition costs of lost earnings by workers who would become temporarily unemployed or underemployed during the adjustment to higher prices for energy from fossil fuels. There would also be indirect effects on household consumption relative to what would happen in the absence of the cap-and-trade program. The premature obsolescence of existing long-lived capital, such as coal-fired power plants that would no longer generate as much electricity, would reduce household wealth a little (through shareholders' losses) and in turn reduce consumption. Both lower household wealth and higher costs of producing energy-intensive capital goods would reduce domestic saving and investment, leading to slightly lower economic growth and household consumption. Finally, some interactions of the cap-and-trade program with existing taxes could tend to add to economic costs. For example, the increase in prices for fossil fuel energy and energy-intensive goods and services would tend to aggravate distortions in the labor market caused by existing taxes on earnings.

The loss in purchasing power would rise over time as the cap became more stringent and larger amounts of resources were dedicated to cutting emissions—for example, by generating electricity from natural gas rather than coal or by improving energy efficiency. As a share of GDP, the aggregate loss of purchasing power would be 0.1 percent in 2012 and 0.8 percent in 2050, CBO estimates, and would average 0.4 percent over the entire 2012–2050 period. Measured at the projected 2010 level of income, the average per-household loss in purchasing power would be $90 in 2012 and $925 in 2050 and would average about $455 per U.S. household per year over the 2012–2050 period.

Effects on Households in Different Income Groups

Estimates of the average loss in purchasing power per household do not reveal the range of effects that the program would have on households in different circumstances, including their income level, sectors of the economy in which they work, and regions of the country in which they live. CBO does not have the capability to estimate effects by region or by sector of employment, but the agency does estimate effects on households of different income levels.

Specifically, CBO estimated the effects of the cap-and-trade program established by H.R. 2454 on households in each fifth of the population arrayed by income (and adjusted for household size) on the basis of the provisions of the program as defined for both 2020 and 2050. The loss in purchasing power that would be faced by households at each point in the income distribution would depend on the amount of compliance costs they would bear minus the amount of offsetting real income they would receive as a result of the policy. To show the burden of the loss in purchasing power that households would experience, CBO presents those losses as shares of after-tax income.

Avenues by Which Households Would Incur Costs and Receive Compensation

Estimating the effects of the cap-and-trade program on households in different income brackets entails accounting for the various means by which households would bear compliance costs and receive compensation in their various roles as consumers, workers, shareholders, taxpayers, and recipients of government services.

Compliance Costs. CBO assumed that businesses would pass the costs of acquiring emissions allowances, purchasing domestic and international offset credits, and reducing emissions on to their customers through higher prices for goods and services. (That assumption, which is standard in distributional analyses, stems from the fact that the price of an item in the long run generally reflects the incremental cost of producing that item.) CBO estimated price increases for categories of goods and services using a model of the U.S. economy that relates final prices of goods to the costs of production inputs. Households and governments would bear those costs through their consumption of goods and services. Households account for the bulk of total spending, and they would bear an estimated 87 percent of the compliance costs. Those costs were allocated among households on the basis of their consumption of those goods and services as reported in the Consumer Expenditure Survey from the Bureau of Labor Statistics.[22]

The federal government and state and local governments would bear the remainder of compliance costs (an estimated 13 percent) through their spending on goods and ser-

22. The database for the analysis was constructed by statistically matching income information from the Statistics of Income data (from the Internal Revenue Service), households' characteristics from the Current Population Survey (reported by the Census Bureau), and data on households' expenditures from the Consumer Expenditure Survey (from the Bureau of Labor Statistics). The data are from 2006, the latest year for which information from all three sources was available, and thus reflect the patterns of income and consumption in that year. The data were extrapolated to 2010 levels using the estimated overall growth in population and income. For the purposes of this analysis, CBO allocated the cost of reducing all of the gases covered in the cap-and-trade program among households and governments on the basis of their contributions to emissions of carbon dioxide, which constitute more than 85 percent of greenhouse gases.

vices. CBO did not distribute governmental costs across households because their incidence was unclear. If governments chose to increase taxes across the board, the cost would fall on households in proportion to their share of federal, state, and local taxes. In contrast, if governments chose to cover the additional expenses by cutting back on the services they provide, the cost would fall on households that no longer received those services.

Emissions Allowances. Under H.R. 2454, the distribution of allowances would change between 2020 and 2050, which would alter the distribution of the loss in purchasing power across households.

In 2020, the government would issue most of the allowances at no cost to private entities, state governments, or the federal government. More specifically:

- 15 percent of the value of the allowances would be set aside for an energy rebate program for households whose gross income does not exceed 150 percent of the federal poverty level or that are receiving benefits through the Supplemental Nutrition Assistance Program, the Medicare Part D low-income subsidy, the Supplemental Security Income program, or other low-income assistance, and for an expansion in the earned income tax credit payable to individuals without qualifying children;

- 16 percent of the value of the allowances would be given to companies that distribute electricity and natural gas, with instructions to pass those benefits on to their residential customers;

- 29 percent of the value of the allowances would be given to those same distributors of electricity and natural gas, with instructions to pass the value on to their commercial and industrial customers;

- 15 percent of the value of the allowances would be given to what are termed trade-exposed, energy-intensive industries—which would be less able to pass their compliance costs on to their customers than would other industries facing less international competition—and oil refiners;

- 18 percent of the value of the allowances would be directed to the federal government and to state governments to spend within the United States (not including the amount used to fund the energy rebate and tax credit). For example, the bill would direct a portion of the value to be spent encouraging the development of particular technologies (such as electricity generation that includes the capture and storage of carbon dioxide) and improvements in energy efficiency; and

- 7 percent of the allowance value would be spent overseas, to fund efforts to prevent deforestation in developing countries, encourage the adoption of more efficient technologies, and assist those countries in adapting to climate change.

The allocation of allowances under the 2050 provisions of the ACESA is quite different from that in 2020, with a much larger fraction of the allowance value flowing directly to households:

- 15 percent of the value of the allowances would continue to be used to fund the energy rebate program and the expansion in the earned income tax credit;
- 54 percent of the allowance value would be used to fund a Climate Change Consumer Refund Account and would be paid on a per capita basis;
- 21 percent of the value would be directed to federal and state governments (not counting the shares allocated for household rebates, tax credits, and refunds) to be spent on various objectives, including encouraging investments in clean energy technology, increasing energy efficiency, facilitating adaptation, and protecting wildlife; and
- 10 percent of the value would be spent overseas to fund efforts to prevent deforestation in developing countries, encourage the adoption of more efficient technologies, and assist those countries in adapting to climate change.

For the allowances given to local distributors of electricity or national gas with instructions to pass the benefits on to their residential customers, CBO assumed that the value of those allowances would be received by those households. For the allowances given to those local distributors with instructions to pass the benefits on to their commercial and industrial customers, CBO assumed that the value of those allowances would be received by shareholders, because that allocation of allowances would not generally reduce the cost of producing an incremental unit of output and thus would not generally be passed through to households in the form of lower prices.[23] For the allowances given to trade-exposed industries and oil refiners, CBO assumed that the value would be passed through in the form of lower prices for customers.[24] With the exception of the allowances used to fund household rebates, refunds, or tax credits, CBO lacked sufficient information to distribute the value of allowances that were given to federal or state governments to spend within the United States. CBO also did not distribute among U.S. households the value of allowances that would be spent overseas.

23. All increased profits, net of taxes, were allocated to households according to their holdings of equities, which were estimated from the Federal Reserve's Survey of Consumer Finances for 2004. Those holdings include equity held through mutual funds and private pension accounts.

24. That approach was used to account for CBO's inability to distribute the initial cost of the cap among such firms. The cost of the emissions cap would tend to fall on workers and shareholders in those industries; correspondingly, the relief aimed at those industries (which would be linked to their level of production) would tend to offset costs that workers and shareholders in those industries would otherwise incur. Because of data limitations, CBO assumed for this analysis that the cost of complying with the cap would lead to price increases for those industries. Correspondingly, CBO reflected the value of allowances allocated to those industries as offsetting price decreases.

Domestic Offset Credits. Covered entities would purchase domestic offset credits to comply with the cap under both the 2020 and 2050 provisions of ACESA. Spending on domestic offsets would rise over time because the increase in the price of allowances would make it cost-effective for firms to comply by purchasing increasingly costly offsets. Suppliers of domestic offset credits would experience increases in net income—the gross income received from selling the offsets minus the costs incurred to generate them.[25]

Additional Financial Transfers and Costs That Would Affect Households. The cap-and-trade program under H.R. 2454 would result in some additional transfers of income—and additional costs—that are not reflected in the gross compliance costs, the disposition of the allowance value, or the net income from domestic offset production. Households would receive additional income in three ways:

- *The value of the rebates and tax credits for low-income households in excess of the 15 percent of the allowance value that the bill would set aside to pay for them.*[26] That amount would add to the sums received by households but would also increase the cost to the government.

- *Increases in government benefit payments that are pegged to the consumer price index, such as Social Security benefits.* Under the assumption that the costs of compliance would be passed through to consumers in the form of higher prices and that the Federal Reserve would not act to offset those price increases, the rise in the consumer price index would trigger increased cost-of-living adjustments in benefits from certain government programs. The increase in those transfer payments would help offset the higher expenditures for the households that received them but would also impose a cost on the federal government.

- *Reduced federal income taxes.* Because the federal income tax system is largely indexed to the consumer price index, an increase in consumer prices with no increase in nominal income would reduce households' federal income tax payments. That effect would increase households' after-tax income but would also add to the federal deficit.

Because each of those transfers of income would have equal and offsetting costs (increased Social Security benefits would ultimately need to be paid for by higher taxes or reductions in other government spending, for example), they would neither

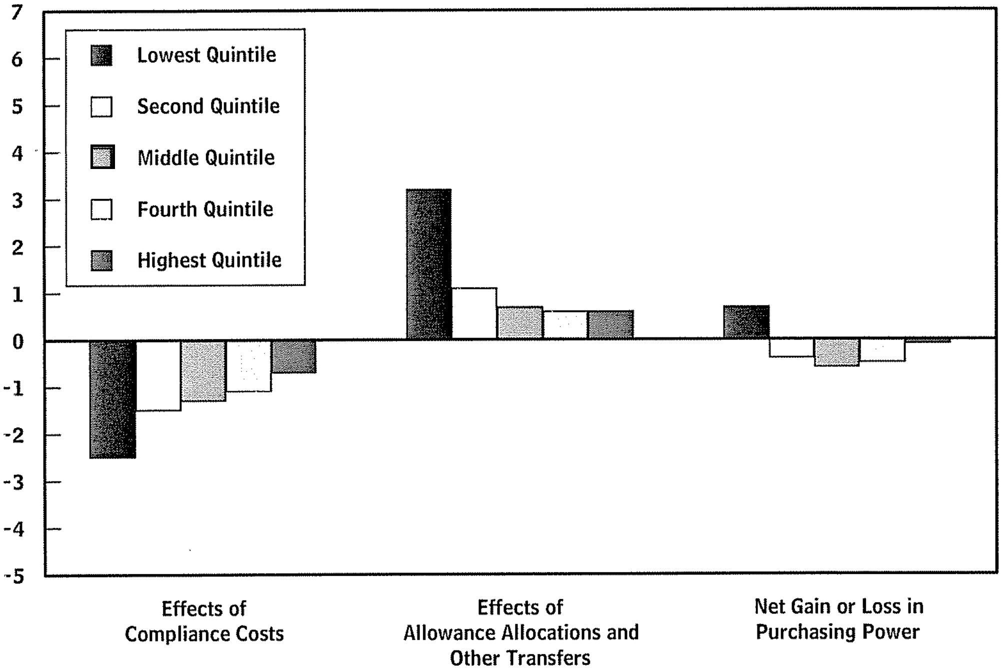
25. Like other profits, increased after-tax net income by providers of domestic offsets was allocated to households according to their holdings of equities, which were estimated from the Federal Reserve's Survey of Consumer Finances for 2004. Those holdings include equity held through mutual funds and private pension accounts.

26. Estimates of the low-income rebates and tax credits were made by CBO and the staff of the Joint Committee on Taxation, respectively.

Figure 1.

Average Gain or Loss in Households' Purchasing Power from the Greenhouse-Gas Cap-and-Trade Program in H.R. 2454, by Level of Income: 2020 Policy Measured at 2010 Levels of Income

(Effects as a percentage of after-tax income)



Source: Congressional Budget Office.

add to nor reduce the loss in purchasing power associated with the policy. However, because CBO was able to distribute the benefits associated with the transfers but lacked sufficient information to distribute the costs, the transfers do affect the estimated distribution of the loss in purchasing power described below.

Effects of the Policy's Provisions in 2020

CBO estimates that households in the lowest income quintile in 2020 would see an average *gain* in purchasing power of 0.7 percent of after-tax income, or about $125 measured at 2010 income levels. Households in the highest income quintile would see a *loss* in purchasing power of 0.1 percent of after-tax income, or about $165 at 2010 income levels (see Figure 1 and Table 2), and households in the middle quintile would experience a loss in purchasing power equivalent to 0.6 percent of after-tax income, or about $310 at 2010 income levels.

Although households in the lowest income quintile would experience a net gain in purchasing power in 2020 under the provisions of H.R. 2454, they would experience

Table 2.

Average Gain or Loss in Households' Purchasing Power from the Greenhouse-Gas Cap-and-Trade Program in H.R. 2454: 2020 Policy Measured at 2010 Levels of Income

	Effects of Compliance Costs	Effects of Allowance Allocations and Other Transfers	Net Gain or Loss in Purchasing Power
	Average Dollar Gain or Loss per Household		
Lowest Quintile	-430	555	125
Second Quintile	-560	410	-150
Middle Quintile	-685	375	-310
Fourth Quintile	-825	455	-375
Highest Quintile	-1,400	1,235	-165
Unallocated	-120 [a]	130 [b]	10
All Households	-900	740	-160
	Gain or Loss as a Percentage of After-Tax Income		
Lowest Quintile	-2.5	3.2	0.7
Second Quintile	-1.5	1.1	-0.4
Middle Quintile	-1.3	0.7	-0.6
Fourth Quintile	-1.1	0.6	-0.5
Highest Quintile	-0.7	0.6	-0.1
Unallocated	-0.2 [a]	0.2 [b]	0
All Households	-1.2	1.0	-0.2

Source: Congressional Budget Office.

Note: The figures are 2010 levels based on the 2006 distribution of income and expenditures. Households are ranked by adjusted household income. Each quintile contains an equal number of people. Households with negative income are excluded from the bottom quintile but are included in the total. The loss from compliance costs is distributed to households on the basis of their carbon consumption.

a. Unallocated compliance costs reflect the governments' share of carbon consumption.

b. CBO did not allocate allowances for which the recipients were unspecified (for example, allowances given to the government to distribute for energy-efficiency improvements). Unallocated gains and losses from other transfers are the net government cost of funding transfers in excess of the allowances allocated for that purpose. On net, the unallocated allowances and unfunded transfers increase purchasing power for the 2020 policy because the unallocated allowances are greater than the unfunded transfers.

the largest financial burden prior to compensation. The price increases triggered by the compliance costs would cause a loss in purchasing power of 2.5 percent of after-tax income for households in the lowest quintile, compared with 0.7 percent of after-tax income for households in the highest quintile. Although the dollar increase in out-of-pocket expenditures stemming from the compliance costs would be substantially larger for high-income households ($1,400) than for low-income households ($430), it would impose a larger proportional burden on low-income households because those households consume a larger fraction of their income and because energy-intensive goods and services make up a larger share of expenditures by low-income households.

In estimating households' loss of purchasing power, CBO lacked sufficient information to allocate across households in different income brackets the benefits of some proposed government spending programs. In addition, the agency was not able to allocate across households the 13 percent of compliance costs that would be borne by the government as well as other expenditures that the federal government would face as a result of the policy and that would not be funded by revenue from the allowances. The government could finance those expenditures in various ways, including increasing taxes or reducing other spending, which could have very different effects on households at different points in the income spectrum. In 2020, the aggregate amounts of benefits and costs that CBO was not able to allocate across households roughly canceled each other out. As a result, the loss in purchasing power that CBO allocated across households in different income brackets was nearly the same as the average loss in purchasing power experienced by all households in aggregate (0.2 percent of after-tax income, or $160 per household when measured at 2010 income levels).[27]

Effects of the Policy's Provisions in 2050

The cap-and-trade program in H.R. 2454 would have different impacts across households in 2050 than in 2020. CBO estimates that households in the lowest income quintile in 2050 would see an average increase in purchasing power equal to 2.1 percent of their after-tax income, or $355 measured at 2010 income levels (see Table 3 and Figure 2). Households in the highest income quintile would see a loss in purchasing power of 0.7 percent of after-tax income, or about $1,360 measured at 2010 income levels, and households in the middle quintile would have a loss in purchasing power of 1.1 percent of after-tax income, or about $590 at 2010 levels.

In 2050, the aggregate amount of costs that CBO was unable to allocate across households would exceed the aggregate amount of unallocated benefits. In particular, the magnitude of the rebates and tax credits for low-income households in 2050 would be significantly larger than the 15 percent of the allowance value set aside to pay for them. In addition, more revenue would be required to fund the increases in indexed benefits (such as Social Security income) that would be triggered by higher prices. As a result, the loss in purchasing power allocated across households in different income

27. That average loss in purchasing power in 2020 is slightly lower than the $175 reported in CBO's June 2009 analysis (and which CBO referred to as "net economywide cost") because of refinements in CBO's methodology and subsequent changes in legislative provisions. In addition, the allocation of the loss in purchasing power across households is different than in the June 19th analysis because the final version of the bill targeted more relief at households in the lowest income quintile. For more information, see Congressional Budget Office, "The Estimated Costs to Households from the Cap-and-Trade Provisions of H.R. 2454," letter to the Honorable Dave Camp (June 19, 2009).

Table 3.

Average Gain or Loss in Households' Purchasing Power from the Greenhouse-Gas Cap-and-Trade Program in H.R. 2454: 2050 Policy Measured at 2010 Levels of Income

	Effects of Compliance Costs	Effects of Allowance Allocations and Other Transfers	Net Gain or Loss in Purchasing Power
	Average Dollar Gain or Loss per Household		
Lowest Quintile	-675	1,030	355
Second Quintile	-880	580	-300
Middle Quintile	-1,075	485	-590
Fourth Quintile	-1,295	500	-795
Highest Quintile	-2,190	830	-1,360
Unallocated	-190 [a]	-200 [b]	-390
All Households	-1,410	485	-925
	Gain or Loss as a Percentage of After-Tax Income		
Lowest Quintile	-3.9	6.0	2.1
Second Quintile	-2.4	1.6	-0.8
Middle Quintile	-2.0	0.9	-1.1
Fourth Quintile	-1.7	0.7	-1.0
Highest Quintile	-1.1	0.4	-0.7
Unallocated	-0.3 [a]	-0.3 [b]	-0.5
All Households	-1.9	0.6	-1.2

Source: Congressional Budget Office.

Note: The figures are 2010 levels based on the 2006 distribution of income and expenditures. Households are ranked by adjusted household income. Each quintile contains an equal number of people. Households with negative income are excluded from the bottom quintile but are included in the total. The loss from compliance costs is distributed to households on the basis of their carbon consumption.

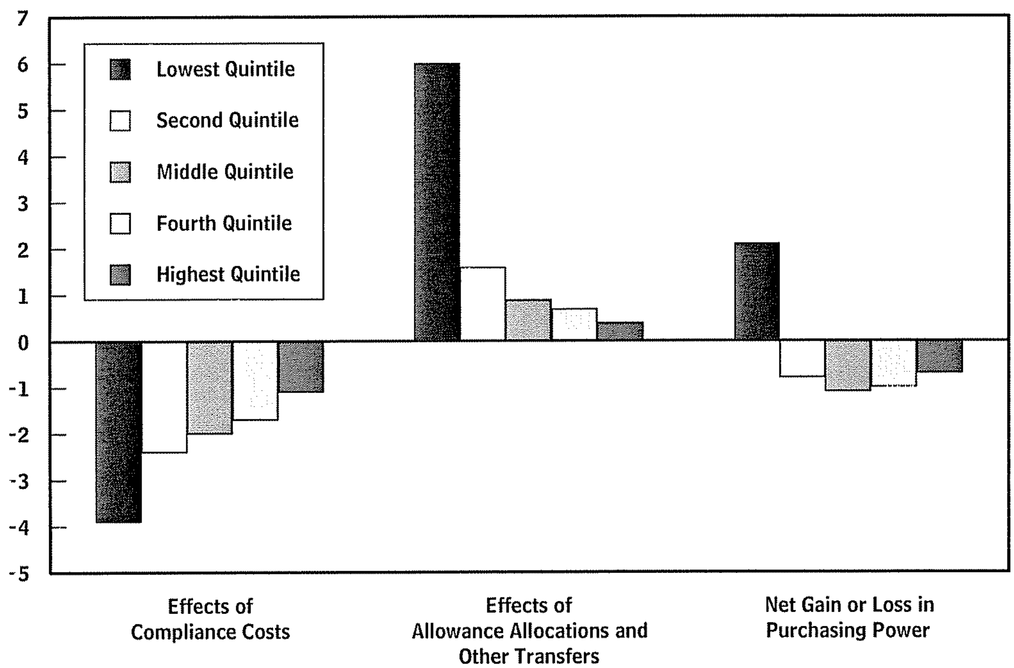
a. Unallocated compliance costs reflect the governments' share of carbon consumption.

b. CBO did not allocate allowances for which the recipients were unspecified (for example, allowances given to the government to distribute for energy-efficiency improvements). Unallocated gains and losses from other transfers are the net government cost of funding transfers in excess of the allowances allocated for that purpose. On net, the unallocated allowances and unfunded transfers decrease purchasing power for the 2050 policy because the unallocated allowances are less than the unfunded transfers.

Figure 2.

Average Gain or Loss in Households' Purchasing Power from the Greenhouse-Gas Cap-and-Trade Program in H.R. 2454, by Level of Income: 2050 Policy Measured at 2010 Levels of Income

(Effects as a percentage of after-tax income)



Source: Congressional Budget Office.

brackets is only about 60 percent of the estimated aggregate loss in purchasing power (1.2 percent of after-tax income, or $925 per household when measured against 2010 income levels).

Comparison of the Effects of the 2020 and 2050 Policy Provisions

The 2020 and 2050 policy provisions and the losses in purchasing power associated with them have some similarities and some differences.

First, the loss in purchasing power stemming from both the 2020 and 2050 policy provisions would impose the largest burden (measured as a fraction of after-tax income) on households in the middle and next-to-highest income quintiles (see Figures 1 and 2).

Second, the amount of compensation received by households in the lowest income quintile would be substantially higher in 2050 than in 2020. Households in the bottom quintile would receive greater relief in 2050 because they would continue to receive protection in their loss of purchasing power through the low-income rebate and tax credit provisions and would also receive refunds through the Climate Change Consumer Refund Account. If the low-income rebates and tax credits that households received were reduced to account for the Climate Change Refunds that they would also receive, the net gain by the average household in the lowest quintile would be about $135.

Third, the ultimate beneficiaries of the value of the allowances would be more certain in 2050 than in 2020 because most of the allowances in 2020 would be distributed to households via private entities or government programs designed to promote new technologies or energy efficiency. As a result, CBO had to make assumptions as to how the allowances given to private entities would ultimately accrue to households. In contrast, most of the allowance value in 2050 would flow to households directly via rebates from the federal government.

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A Report for NWPCC

Forecasting the Future Value of Carbon

A Literature Review of Mid- to Long-Term Carbon Price Forecasts

January 30, 2009

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1 Introduction

The Northwest Power and Conservation Council (NWPCC) is currently developing its next Northwest Power Plan. As part of this process, NWPCC is considering the impacts of climate change policy on its resource planning. This report is designed to deliver insight into how CO_2 liability costs may evolve in a carbon-constrained world, so as to assist NWPCC in incorporating potential future CO_2 liabilities into its planning process for the power system in the Pacific Northwest.

Climate change mitigation policy is evolving relatively rapidly both internationally and domestically, and the cost of complying with future greenhouse gas (GHG) emissions constraints is becoming an increasingly important consideration in evaluating the financial performance of companies, projects and investments that have significant exposure to potential GHG mandates.

As pollutants, GHGs are notable for several reasons. First, they mix effectively in the atmosphere and, indeed, any given molecule of CO_2 emitted through human activities can be shifted anywhere in the atmosphere within a matter of days. Second, GHGs tend to have long atmospheric residence times and do not quickly precipitate out of the atmosphere as do pollutants like sulfur dioxide (SO_2). Moreover, GHG emissions do not pose local health risks as do criteria pollutants (i.e. there is no risk of GHG "hot spots.")

This combination of characteristics means that GHGs are uniquely suited to market-based approaches that achieve least-cost compliance with emission reduction mandates. This is precisely the reason emissions trading has received so much attention during the development of both domestic and international climate change policy. Properly structured, emissions trading can significantly cut the costs of achieving any given reduction target.

Emissions trading can in principle occur at multiple levels, and it is possible to envision simultaneous domestic, regional, and international trading programs. Each of these programs could, in theory, have different market clearing prices owing to different operating rules and differing access to cost-effective emissions reduction opportunities. From the standpoint of projecting carbon prices in a carbon-constrained world, however, trying to anticipate the range of potential geography- or sector-specific trading markets simply adds too much complexity to an analysis of future carbon prices, and the uncertainty bands around such projections would render the projections themselves of questionable value.

For these reasons, a relatively high-level look at GHG markets is likely to generate the most useful insight into the economic implications of future carbon constraints. An international GHG market-clearing price, for example, reflecting a market that is able to take advantage of the broadest array of emission reduction options, will reflect a conservative estimate of the economic impacts associated with any given level of carbon emissions constraint. This makes political sense since political pressures, given enough time, will likely shrink any major differential between the market-clearing prices in domestic and international GHG trading systems

There remains a good deal of uncertainty regarding the manner through which GHGs will be regulated and how the markets will respond as a result. Policy options such as cap-and-trade programs and carbon taxes offer regulatory options with distinct costs and benefits.

Debating the use of carbon taxes versus cap-and-trade programs is popular among policymakers wishing to address the issue of climate change. On the one hand, a carbon tax sets a price that regulated emitters must pay for every ton of GHG they release into the atmosphere above a given level. A cap-and-trade program, in contrast, sets a limit on GHG emissions themselves. Under a cap-and-trade, the regulating body issues "allowances" to capped entities, representing the right to emit a certain amount of GHGs. Allowance holders that reduce their emissions below this amount may sell their allowances to those who exceed their cap. Thus, a carbon tax fixes the *price* of carbon while leaving the environmental results uncertain, while a cap-and-trade program fixes the *quantity* of emissions while letting price be determined by the market.

Those who support a carbon tax consider price reliability to be of key importance. If the costs of regulation are certain, decision-makers can make investments based on predictable, long-term energy prices. They also argue that taxes are more easily implemented and more transparent than cap-and-trade systems. Cap-and-trade advocates, on the other hand, point to the political challenges associated with imposing a carbon tax significant enough to materially influence GHG emissions. Given the short window of time we have to address the climate change problem, they argue, it is better to be certain of the environmental result than of the cost.

Politicians historically favor cap-and-trade systems; the current regulatory climate—both in the United States and abroad—generally favors the development of such programs. Established systems include emissions trading under the Kyoto Protocol, the European Union Emission Trading Scheme (EU ETS), and the New South Wales (NSW) Greenhouse Gas Abatement Scheme. Within the US, two cap-and-trade systems—the Regional Greenhouse Gas Initiative (RGGI) and the Western Climate Initiative (WCI)—are in advanced stages of development, while the proposed Boxer-Lieberman-Warner bill would establish a comprehensive federal program. The Chicago Climate Exchange (CCX), a voluntary but legally-binding cap and trade program, has been trading emission allowances among participating entities since 2003.

Despite the popularity of cap-and-trade systems as a regulatory means of managing GHGs, forecasting the future value of carbon in a carbon-constrained world is usually done through GHG price forecasting models that use a carbon tax proxy to forecast carbon prices even in a cap-and-trade scenario. This is the case because macro-economic models are the most useful way to forecast long-term carbon costs given the complexity of the impacts of a carbon constraint on national and global economies, and the many feedbacks that are involved. That said, the use of a carbon tax proxy in most modeling represents yet another complicating variable in confidently forecasting future GHG prices.

The models profiled in this review were chosen based on their relative transparency and credibility, and to reflect a range of models and approaches in order to provide a wider perspective on the forecasting of GHG prices.

2 GHG Price Forecasting Introduced

This section of the report attempts to highlight the key attributes of a variety of GHG price forecasting approaches.

2.1 The Various Approaches to GHG Price Forecasting

Many studies and observers have projected or are projecting GHG prices. These projections are commonly based on several approaches:

- *Top-down models* are usually macroeconomic in structure. Their estimates are highly influenced by economic growth, energy mix, and compliance system flexibilities assumed by the modeler. These models generally do not specifically incorporate supply and demand for carbon offsets, but instead rely on a carbon-tax proxy for purposes of estimating mitigation costs. As a result, a specific GHG "commodity" is generally not defined for purposes of these models. Top-down models often generate price projections ranging from $1 to $30 per ton, although some predict costs well in excess of $100 per ton.

- *Bottom-up models* are usually project- or technology- specific. They often utilize mitigation cost curves that suggest that large-scale mitigation is available cheaply, often less than $5/ton. These estimates, however, tend to be based on social costing rather than private cost methodologies (i.e., benefits such as the dollar savings associated with energy efficiency are included in the calculation, even though they don't actually accrue to the private entity funding the mitigation project to generate a carbon credit). Thus, they are often hard to translate into GHG market price forecasts.

- *"By analogy" forecasting* extrapolates from experience with other environmental commodities to the GHG market. Many observers, for example, have argued that because SO_2 allowance prices were much lower than anticipated when a trading system was implemented, GHG credit prices will also fall from current levels once a formal trading system is implemented. Unfortunately, the conclusions commonly drawn from an analogy-based approach fundamentally mischaracterize the relationship between SO_2 and CO_2 emission reduction potentials. SO_2 allowance price projections, for example, were based on technology-based market clearing prices (e.g., FGD construction). Most CO2 price projections, however, are already based on assuming access to the lowest cost mitigation options, as opposed to assuming that mitigation will be accomplished through carbon capture and sequestration (CCS) or other "high tech" interventions. In terms of technologies that could cap GHG credit prices, a survey of many CO_2 avoidance technologies suggests that many technologies become available at costs of $50-100 per ton.

- *"Historical extrapolation" forecasting* is often used as the basis from which to project price trends. Given the early stages of the GHG market, however, and the fact that most of its key attributes remain to be finalized (including commodity definition, supply, and demand), looking to historical prices in voluntary or even limited regulatory markets to date is a risky approach.

- *"Expert surveys"* are often used in forecasting future GHG prices based on the premise that people familiar with the market have the most insight into where prices are likely to head. This approach, however, clearly suffers from a "groupthink" phenomenon, in which everyone tends to end up with the same forecast. In addition, it can be difficult to separate out an individual's market projections from their own self-interest. For example, the brokerage community clearly has an interest in motivating near-term transactions by arguing that prices are rising, and that now is the time to buy. Some regulated industries in Canada and Europe have also had an interest in forecasting very high credit prices in an effort to get more generous allowance allocations or other favorable policy dispensations in the near term. Neither necessarily reflects supply and demand realities in the market.

It is important when forecasting GHG prices to understand the strengths and limitations of each approach profiled above, and the source of estimates used by advocates or in the press. Furthermore, it is important to assess how each approach can contribute to constructive policy and corporate planning and decision making. Table 1 provides a short review of the strengths and weaknesses of each approach. While each forecasting approach has its advantages, in the end none of the approaches alone is likely to be able to provide a sufficient foundation for carbon price forecasting for serious policy and corporate decision-making. A key limitation of each of these approaches is that they often do not provide a clear picture of the policy scenario associated with a given price projection. In reality, carbon markets and market-clearing prices will be profoundly dependent on the details of the policy scenario that is being implemented, since these details will largely determine both the demand for emissions reductions, and the shape of the emissions reduction supply curve. Carbon markets are truly policy-based markets, and are thus fundamentally different than conventional commodity markets.

Approach	Strengths	Limitations
Top Down Analysis	Assesses the economy-wide effects of a change in energy prices.	Does not define the project-level reductions being accomplished. Unable to differentiate between BAU and non-BAU reductions at the project level.
Bottom-up Analysis	Provides detailed insight into the mitigation opportunities of specific sector(s).	Generally unable to differentiate between BAU and non-BAU reductions. Often use social cost estimates that are difficult to compare, and don't reflect private sector investment costs. Unable to incorporate feedbacks.
Experience with Current Environmental Commodity Systems	Build upon the proven ability of trading systems to help lower overall implementation costs.	Many characteristics of the GHG market and eventual GHG commodity are fundamentally different than those encountered in previous environmental markets.
Extrapolating from Current Market Trends	Based on empirical evidence of what has been happening in the GHG marketplace.	The historic GHG market is not necessarily predictive of future GHG markets, and it does not incorporate policy decisions that will define the carbon market commodity.

Table 1: Summary Assessment of Common Approaches to GHG Price Forecasting

3 GHG Market Modeling: An Overview of Results

This section of the report reviews a range of analyses that have compared modeling results in forecasting carbon costs in a carbon-constrained world. The models discussed here are publicly available.

- The EMF 16 Study
    - Macro-economic study of a variety of models primarily producing pre-2020 carbon cost projections

- The DICE Model
    - Macro-economic model which utilizes a global average figure for emissions and project prices for a variety of scenarios out to 2025

- The CCSP Report
    - Integrated assessment using three models to predict carbon costs out to 2030, assuming alternative radiative forcing targets.

- The Pew Center Analysis
    - Report on six model outcomes (all using different assumptions) projecting the carbon costs associated with the proposed Lieberman-Warner Climate Security Act.

- The EMF 21 Study
    - Macro-economic study of a variety of models producing carbon cost projections out to 2025, assuming distinct radiative forcing targets

ECL focuses on these reports and models due to their time horizons, the variety of approaches reflected, the variety of assumptions made, and the different geographical scopes included. We have highlighted the range of predicted prices, and have included summary bullets regarding key assumptions underlying different modeling results.

3.1 Key Modeling Variables

Each model reviewed in this section differs in terms of its inherent structure. Apart from structural differences, however, several variables can be identified as the most significant in influencing estimates of the cost of achieving future carbon emissions constraints.

- *Socioeconomic assumptions, GDP growth, primary energy needs, and baseline emissions.* All other things being equal, higher GDP development, higher primary energy use, and higher baseline emissions will result in higher costs associated with achieving a given CO_2 concentration target. Reference scenarios were not identical among the models, and baseline emissions projections vary substantially.

- *Primary energy mix and available technology.* The cost of CO_2 controls also depends on the assumptions regarding the composition of the primary energy mix (i.e. fossil-fuel use vs. other fuels. The different models sometimes assume very different energy mixes, as well as energy prices).

- *Carbon sequestration and other carbon control technologies.* The third core determinant of CO_2 control costs involves differences in the assumed cost of carbon capture, and the relative reliance on this technology for CO_2 mitigation. Some models assume rapid "learning" in these two areas, and end up with much lower CO_2 control costs than models now making the same assumption.

- *Discount rates and assumptions that affect the timeframe or ease of implementing reductions.* The discount rate and timeframe over which models assume reductions to occur have a significant impact on the ultimate presumed value of carbon. Those models that assume low discount rates will typically generate higher net-present-values for carbon-credit projects, than models that assume greater discount rates for similar projects within the same time period.

3.2 GHG Price Modeling Results

3.2.1 The EMF 16 Study (1999)

The most notable macroeconomic modeling studies concentrating on the pre-2020 period were featured in Stanford University's Energy Modeling Forum (EMF) 16 study, published in 1999. (See Table 2 for a summary of the study). The EMF 16 study contained a wide range of model results associated with implementation of the Kyoto Protocol. The range of results published in the EMF 16 reflects structural differences and differences in model assumptions. Although some models featured carbon taxes for the long term (e.g., AIM, RICE), most models in this study concentrated on near-term (pre-2020) price projections. The EMF study assumed that all Annex I countries would maintain their Kyoto targets throughout the analyzed period under three market scenarios: (1) without trading, (2) with trading between industrialized countries only, and (3) with global trading. The meta-analysis provided in the 1999 study uses carbon taxes as a proxy for measuring the economic costs of implementing the Kyoto Protocol. The carbon tax proxy is intended to provide a rough estimate of how much energy prices would have to be increased in order to stabilize emissions at 7 percent below 1990 emissions by 2012.

Model	2010 Carbon Price, US$1990		
	No trading	Annex I trading	Global trading
ABARE-GTEM	87.7	28.9	6.3
AIM	41.7	17.7	10.4
CETA	45.8	12.5	7.1
G-Cubed	20.4	14.4	5.4
MERGE3	71.9	36.8	23.4
MS-MRT	64.3	21.0	7.4
RICE	51.2	16.9	4.9
Median	51.2	16.9	7.1

Table 2: EMF 16 Carbon Price Forecasts

As shown in Table 3 there is a wide variance in the anticipated carbon costs between and within the models, with a price variance of nearly $70/ton in the 'no trading' scenario alone (which effectively amounts to a carbon tax, as emitters must purchase carbon permits), and similarly-high ranges in the 'Annex I' and 'global trading' model results. This range can be partially attributed to an element of the study that fixed an absolute Kyoto target relative to the 1990 base year. Different emission growth rates assumed by the different models therefore led to divergent cost estimates.

3.2.2 *The DICE Model (2008)*

Unlike the Regional Integrated model of Climate and the Economy (RICE) model (included in the EMF 16 study) the Dynamic Integrated model of Climate and the Economy (DICE) model aggregates emissions data from all major countries into a global average. (See Table 3 for a summary of the DICE model outputs.) DICE's near-term projections consider various scenarios for global carbon (Nordhaus, W., "A Question of Balance: Weighing the Options on Global Warming Policies," 2008), including prices for carbon where atmospheric stabilization occurs at 1.5, 2, and 2.5 times the current concentration of CO_2; various levels of increased temperature; Kyoto Protocol outcomes that include US participation and no US participation; and a number of carbon control proposals. Model results are detailed in Table 3 below.

Policy	Carbon Price, US$2005		
	2005	2015	2025
No controls			
250-year delay	0.02	0.01	0.01
50-year delay	0.02	0.01	0.01
Optimal	7.43	11.42	14.55
Concentration limits			
Limit to 1.5x CO_2	39.25	67.47	114.96
Limit to 2x CO_2	7.97	12.29	15.99
Limit to 2.5x CO_2	7.43	11.42	14.55
Temperature limits			
Limit to 1.5°C	29.02	47.60	73.28
Limit to 2°C	12.34	19.57	27.86
Limit to 2.5°C	8.53	13.21	17.45
Limit to 3°C	7.60	11.69	14.98
Kyoto Protocol			
Kyoto with US	0.02	4.09	4.28
Kyoto without US	0.02	0.43	0.29
Strengthened	0.02	5.40	14.48
Stern Review	67.84	91.66	111.36
Gore proposal	6.81	25.65	72.13
Low-cost backstop	1.36	1.33	0.75

Table 3: DICE Carbon Price Forecasts

In Table 3, the scenarios examined fall into seven general categories: no controls, optimal policy, concentration limits, temperature limits, Kyoto Protocol, ambitious proposals, and low-cost backstop technology. The following is a brief recap of the elements in Table 3:

- The 'No Controls' scenarios assume that governments take no action to stem carbon emissions.

- The 'Optimal Policy' scenario balances mitigation costs with the probable long-term damages from climate change (this scenario is based on an assumption of 100% participation and compliance).

- The 'Concentration Limits' and 'Temperature Limits' scenarios assume concentration limits of 1.5, 2, and 2.5 times preindustrial levels (420ppm, 560ppm, and 700ppm respectively) and temperature restraints of 1.5°C, 2°C, 2.5°C, and 3°C.

- The three 'Kyoto Protocol' scenarios profiled in this study include one in which current emission restrictions are extended out to the end of the modeling period and the United States *does* participate, one with Kyoto restrictions extended while the US does *not* participate, and one that assumes a strengthened Protocol with greater country participation (every region apart from sub-Saharan Africa) and greater emission reduction obligations (10% to start, and an additional 10% every 25 years).

- The 'Ambitious Proposals' scenarios (so called due to their requirement for material emission reductions within the short term) comprise suggested action plans from the *Stern Review* and from Al Gore.

- The 'Stern Review' scenario assumes the future damage from climate change to be material; this is reflected through a comparatively low discount rate in its model run. The Gore scenario assumes a 90% emission-control rate by 2050, and that country participation in the reduction scheme becomes universal within the same time period.
  The 'Low-cost Backstop' scenario models the repercussions of a climate-friendly technology that can replace fossil fuel use at comparable costs. The numbers are low given the relative "cheapness" of the technologies assumed.

3.2.3 The CCSP Report (2007)

The Climate Change Science Program's (CCSP) "Scenarios of Greenhouse Gas Emissions and Atmospheric Concentrations" employs three integrated assessment models—the Integrated Global Systems Model (IGSM), the Model for Evaluating the Regional and Global Effects (MERGE) of GHG reduction policies, and the MiniCAM Model—to analyze the effect of four increasingly-stringent radiative forcing targets in the year 2100. (See Table 4 for a summary of the CCSP report.) The targets range from 3.4 W/m^2, 4.7 W/m^2, 5.8 W/m^2, and 6.7 W/m^2. (Watts per square meter is a measure of energy in a given area.) These targets translate roughly into CO_2 concentrations of 450, 550, 650, and 750 ppm respectively. It should be noted that these equivalencies are approximate and tend to vary among the models. Each model has different assumptions regarding the quantity and behaviour of the GHGs that would lead to these levels. The MERGE model utilized in the CCSP report is an updated version from that used in the EMF 16 study.

Model	Carbon Price, US$2000			
	6.7 W/m^2	5.8 W/m^2	4.7 W/m^2	3.4 W/m^2
2020				
IGSM	4.9	8.2	20.4	70.6
MERGE	0.3	0.5	2.2	30.0
MiniCAM	0.3	1.1	4.1	25.3
2030				
IGSM	7.1	12.0	30.5	104.6
MERGE	0.5	1.1	3.5	52.0
MiniCAM	0.5	1.9	7.1	46.3

Table 4: CCSP Carbon Price Forecasts

The range in carbon prices in the CCSP report stem from the differing assumptions that form the basis of each of the models used for the study. Each model worked with different expectations regarding probable CO_2 emissions over the next century, the role that technology will play, and the ease of mitigating non-CO_2 greenhouse gases.

3.2.4 Pew Center Analysis (2008)

A Pew Center analysis of the recent Lieberman-Warner Climate Security Act (an amended version of which was recently proposed to Congress) compares allowance price estimates derived from each of the models listed in Table 5. Lieberman-Warner would reduce emissions to 71% below the 2005 level by 2050 through caps on coal-consuming and high-emitting entities (facilities that use over 5,000 tons of coal or over 10,000 t CO_2e of GHGs per year), and those entities producing or importing certain fuels. Flexible mechanisms included in the Act include the trading, banking, and (limited) borrowing of allowances, the limited use of offsets, and limited linkages with international carbon trading systems.

Model	Carbon Price US $2005	
	2020	2030
EIA: Core Scenario	29	59
CATF	22	48
ACCF/NAM: Low Cost	52	216
ACCF/NAM: High Cost	61	257
MIT: Offsets + CCS	58	86
EPA (ADAGE): Scenario 2	37	61
EPA (ADAGE): Scenario 10	28	46
CRA: Scenario with Banking	58	84

Table 5: Lieberman-Warner Compliance Carbon Price Forecasts

Prices in Table 5 range from \$22 to \$61 per t CO_2 in 2020 and \$48 and \$257 per t CO_2 in 2030. This variation can be accounted for in a number of ways: the models each used different assumptions regarding the use of offsets, for example (the CATF model assumed that up to 30% of emissions could be covered with offsets, while the ACCF/NAM model's high-cost scenario assumed only 14%), and each used a different assumption regarding the role of technology, banking, and the use of revenues from the auctioning of allowances.

3.2.5 EMF 21 Model (2006)

Stanford University's Energy Modeling Forum (EMF) 21 study features the most relevant macro-economic studies regarding the post-2020 period (Weyant, J.P., "Overview of EMF-21: Multigas Mitigation and Climate Policy," Energy Journal, Volume 27—Multi-Greenhouse Gas Mitigation and Climate Policy Special Issue, 2006). (See Table 6 for a summary of the EMF 21.) The modeling teams in the EMF 21 study ran two main scenarios:

1. An emission target for the year 2150 that stabilizes radiative forcing at 4.5 W/m^2 using only CO_2 mitigation, and

2. An emission target for the year 2150 that stabilizes radiative forcing at 4.5 W/m^2 using multi-gas mitigation.

Model	2025 Carbon Price, US$2000	
	CO_2 only	Multigas
AIM	30.52	17.71
AMIGA	19.75	13.35
COMBAT	21.58	18.31
EDGE	1.50	0.79
EPPA	30.16	11.50
FUND	131.39	107.36
GEMINI-E3	24.22	8.58
GRAPE	3.38	1.88
GTEM	59.86	32.59
IMAGE	27.74	14.47
IPAC	23.84	10.22
MERGE	6.21	2.92
MESSAGE	11.47	3.57
MiniCAM	6.84	2.78
PACE	0.76	0.41
POLES	23.46	14.69
SGM	62.94	17.71
WIAGEM	11.31	4.41
Mean	27.60	15.75

Table 6: EMF 21 Carbon Price Forecasts for 2025

The models employed in EMF 21 each operate based on a different set of assumptions regarding future population estimates, energy prices, economic growth, technology advancements, and mitigation options. Baselines varied accordingly among the models: models such as AIM, IMAGE, IPAC, and MESSAGE project that emissions will be roughly twice their current level by 2100, while models such as FUND project emissions will be 5 times their current level within the same time period. Treatment of "natural" (i.e., non-anthropogenic) emissions was similarly varied, and led to considerable differences between carbon price projections.

4 Conclusions

The highest price projection found in this survey resulted from the ACCF/NAM model, estimating that a carbon price of $257 would be needed by 2025 to accomplish the emissions reduction objective in its "High Cost" scenario. This model's "High Cost" scenario assumed that only 14% of GHG emissions could be offset, while the remaining emissions had to be internally mitigated. This scenario also strictly limited the rate at which technologies are developed and implemented, including a constraint on nuclear by allowing only 10-25 GW of additional capacity by 2030.

The lower price projections profiled in this report resulted from the PACE model, estimating that a carbon price of only $0.41 would be needed by 2025 to accomplish the emissions reduction objective in its "Multigas" scenario, and the MERGE and MiniCAM models, estimating a required carbon price of only $0.30 in 2020 for the "6.7 W/m2" scenario. The PACE model gave low values partially as a result of assuming a relatively low GHG emissions baseline and emissions growth over time.

This survey provides useful insight into the range of carbon values that are being talked about in the medium- to long-terms, and some of the key assumptions that contribute to this range, including:

- Socioeconomic Baseline and Associated GHG Emissions
- Emissions Reduction Target, Timeframe of Analysis, and Geographic Scope
- Covered GHG Gases
- Carbon Tax vs. Cap and Trade
- Emissions Trading Rules, Including Access to Carbon Offsets
- Technology Advancement Rates and Associated Mitigation Costs

The survey illustrates that the range of forecasts is wide, based on variations not only in the structure of the models, but in the treatment of key variables. It should not be surprising that based on widely varying inputs and assumptions, different models will give very different results. It would therefore be a mistake to draw the conclusion from this survey that carbon price forecasting is fundamentally so uncertain that we can't learn anything from it. As one zeroes in on a specific set of assumptions, many of the model results become much more consistent.

Making GHG market modeling useful for corporate and policy planning purposes requires building a preferred policy scenario around which a market forecast can be built. With a detailed enough specification of key policy and market variables, one can often generate a Best

Available Forecast that can provide considerable insight into how carbon markets may function to generate carbon prices in such a scenario. EcoSecurities Consulting Ltd. was not asked to develop such a scenario or forecast for NWPCC, although one of the reports prepared for NWPCC does profile potential carbon prices under a variety of high-level policy scenarios.

Annex 1 GHG Price Modeling Featured in the EMF 16 and 21 Studies

Acronym	Full Model Name	Author(s)/Home Institution(s)	Featured In
ABARE-GTEM	Global Trade and Environment Model	B. Fisher and V. Tulpulé	EMF 16
AIM	Asian Pacific Integrated Model	M. Kainuma, T. Morita, T. Masui, K. Takahashi (NIES) and Y. Matsuoka (Kyoto University)	EMF 16, EMF 21, and EMF 19 (not discussed in this report)
AMIGA	All Modular Industry Growth Assessment	D. Hansen (Argonne National Laboratory, U.S.), J. Laitner (U.S. EPA)	EMF 21
COMBAT	Comprehensive Abatement	H.A. Aahaim, J.S. Fuglestvedt, and O. Godal (CICERO, Norway)	EMF 21
EDGE	European Dynamic Equilibrium Model	J. Jensen (TECA TRAINING ApS)	EMF 21
EPPA	Emissions Projection & Policy Analysis Model	J. McFarland, J. Reilly, H. Herzog (MIT)	EMF 16, EMF 21, and EMF 19 (not discussed in this report)
FUND	Climate Framework for Uncertainty, Negotiation, and Distribution	Richard Tol (Economic and Social Research Institute, Ireland and Hamburg, Vrije & Carnegie Mellon Universities)	EMF 21
GEMINI-E3	General Equilibrium Model of International Interaction for Economy-Energy-Environment	A. Bernard (Min. of Equipment, Transport, and Housing, France), M. Vielle (CEA-LERNA, France), and L. Viguier (HEC Geneva and Swiss Federal Institute of Technology)	EMF 21
GRAPE	Global Relationship Assessment to Protect the Environment	A. Kurosawa (Institute of Applied Energy, Japan)	EMF 16, EMF 21, and EMF 19 (not discussed in this report)
GTEM	Global Trade and Environment Model	G. Jakeman and B. Fisher (Australian Bureau of Agricultural and Resource Economics)	EMF 21
IMAGE	Integrated Model to Assess The Global Environment	D.P. van Vuuren, B. Eickhout, P.L. Lucas and M.G.J. den Elzen (National Institute for Public Health and the Environment, The Netherlands)	EMF 21
IPAC	Integrated Projection Assessments for China	K. Jiang, X. Hu, & S. Zhu (Energy Research Institute, China)	EMF 21
MARIA	Multiregional Approach for Resource and Industry Allocation	S. Mori (Tokyo University) and T. Saito (Hitachi)	EMF19 (not discussed in this report)
MERGE	Model for Evaluating Regional and Global Effects of GHG	A. Manne (Stanford University) and R. Richels (Electric Power Research Institute)	EMF 16, EMF 21, and EMF 19 (not

	Reductions Policies		discussed in this report)
MESSAGE	Model for Energy Supply Strategy Alternatives and Their General Environmental Impact	K. Riahi, L. Schrattenholzer (ECESP) and E. Rubin, D. Hounshell (Carnegie Mellon University) and M. Taylor (UC Berkeley)	EMF 21 and EMF 19 (not discussed in this report)
MiniCAM	Mini-Climate Assessment Model	J. Edmonds, J. Clarke, J. Dooley, S. Kim, Steven Smith (University of Maryland)	EMF 21 and EMF 19 (not discussed in this report)
PACE	Policy Analysis with Computable Equilibrium	C. Böhringer, (University of Heidelberg), A. Löschel (Centre for European Economic Research – ZEW, and T. Rutherford (University of Colorado)	EMF 21
POLES	Prospective Outlook on Long-Term Energy Systems-Global Emissions Control Strategies	P. Criqui (Institute of Energy Policy and Economics, France), Peter Russ (EC- Institute for Prospective Technological Studies, Spain), and Daniel Deybe (EC Environment DG)	EMF 21
MS-MRT	Multi-Sector – Multi-Region Trade Model	Charles River Associates, University of Colorado	EMF 16
Oxford	Oxford Economic Forecasting	Oxford Economic Forecasting	EMF 16
RICE	Regional Integrated Climate and Economy Model	Yale University	EMF 16
SGM	Second Generation Model	Batelle Pacific Northwest National Laboratory	EMF 16
TIMER	TARGETS-IMAGE Energy Regional model	D. van Vuuren, B. de Vries, B. Eickhout, T. Kram (National Institute of Public Health and the Environment)	EMF 19 (not discussed in this report)
WIAGEM	World Integrated Applied General Equilibrium Model	C. Kemfert (German Inst. of Economic Research & Humboldt University), T. P. Truong (Univ. of New South Wales, Australia) and T. Bruckner (Institute for Energy Engineering, Tech Univ, Germany)	EMF 21
WorldScan	WorldScan	Central Planning Bureau (Netherlands)	EMF 16

Congressional Research Service

Carbon Capture and Sequestration (CCS)

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Prepared for Members and Committees of Congress

Summary

Carbon capture and sequestration (or storage)—known as CCS—has attracted interest as a measure for mitigating global climate change because large amounts of carbon dioxide (CO_2) emitted from fossil fuel use in the United States are potentially available to be captured and stored underground or prevented from reaching the atmosphere. Large, industrial sources of CO_2, such as electricity-generating plants, are likely initial candidates for CCS because they are predominantly stationary, single-point sources. Electricity generation contributes over 40% of U.S. CO_2 emissions from fossil fuels.

Congressional interest has grown in CCS as part of legislative strategies to address climate change. On February 13, 2009, Congress passed the American Recovery and Reinvestment Act of 2009 (ARRA, P.L. 111-5), which included \$3.4 billion for projects and programs related to CCS. Of that amount, \$1.52 billion would be made available for a competitive solicitation for industrial carbon capture and energy efficiency improvement projects, \$1 billion for the renewal of FutureGen, and \$800 million for U.S. Department of Energy Clean Coal Power Initiative Round III solicitations, which specifically target coal-based systems that capture and sequester, or reuse, CO_2 emissions. The \$3.4 billion contained in ARRA greatly exceeds the federal government's cumulative outlays for CCS research and development since 1997.

The large and rapid influx of funding for industrial-scale CCS projects may accelerate development and deployment of CO_2 capture technologies. Currently, U.S. power plants do not capture large volumes of CO_2 for CCS, even though technology is available that can potentially remove 80%-95% of CO_2 from a point source. This is due, in part, to the absence of either an economic incentive (i.e., a price for captured CO_2) or a regulatory requirement to curtail CO_2 emissions. In addition, DOE estimates that CCS costs between \$100 and \$300 per metric ton (2,200 pounds) of carbon emissions avoided using current technologies. Those additional costs mean that power plants with CCS would require more fuel, and costs per kilowatt-hour would be higher than for plants without CCS.

After CO_2 is captured from the source and compressed into a liquid, pipelines or ships would likely convey the captured CO_2 to storage sites to be injected underground. Three main types of geological formations are being considered for storing large amounts of CO_2 as a liquid: oil and gas reservoirs, deep saline reservoirs, and unmineable coal seams. The deep ocean also has a huge potential to store carbon; however, direct injection of CO_2 into the deep ocean is still experimental, and environmental concerns have forestalled planned experiments in the open ocean. Mineral carbonation—reacting minerals with a stream of concentrated CO_2 to form a solid carbonate—is well understood, but it also is still an experimental process for storing large quantities of CO_2.

The increase in funding for CCS provided for in ARRA and by other economic incentives may lead to less expensive and more effective technologies for capturing large quantities of CO_2. Without a carbon price or a regulatory requirement to cap CO_2 emissions, however, it will be difficult to predict or evaluate how the technology would be deployed throughout the U.S. energy sector. By comparison, transporting, injecting, and storing CO_2 underground may be less daunting. A large pipeline infrastructure for transporting CO_2 could be very costly, however, and considerable uncertainty remains over how large quantities of injected CO_2 would be permanently stored underground. To help resolve these uncertainties, DOE has initiated large-scale CO_2 injection tests in a variety of geologic reservoirs that are to take place over the next several years.

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Introduction

Carbon capture and sequestration (or storage)—known as CCS—is capturing carbon at its source and storing it before its release to the atmosphere. CCS would reduce the amount of carbon dioxide (CO_2) emitted to the atmosphere despite the continued use of fossil fuels. An integrated CCS system would include three main steps: (1) capturing and separating CO_2; (2) compressing and transporting the captured CO_2 to the sequestration site; and (3) sequestering CO_2 in geological reservoirs or in the oceans. As a measure for mitigating global climate change, CCS has attracted congressional interest because several projects in the United States and abroad—typically associated with oil and gas production—are successfully capturing, injecting, and storing CO_2 underground, albeit at relatively small scales. The oil and gas industry in the United States injects approximately 48 million metric tons of CO_2 underground each year to help recover oil and gas resources (enhanced oil recovery, or EOR).[1] Also, potentially large amounts of CO_2 generated from electricity generation—over 40% of the total CO_2 emitted in the United States from fossil fuels, nearly 2.4 billion metric tons per year—could be targeted for large-scale CCS. (See **Table 1.**)

Fuel combustion accounts for 94% of all U.S. CO_2 emissions.[2] Electricity generation contributes the largest proportion of CO_2 emissions compared to other types of fossil fuel use in the United States. (See **Table 1.**) Electricity-generating plants are among the most likely initial candidates for capture, separation, and storage or reuse of CO_2 because they are predominantly large, stationary, single-point sources of emissions. Large industrial facilities, such as cement-manufacturing, ethanol, or hydrogen production plants, that produce large quantities of CO_2 as part of the industrial process are also good candidates for CO_2 capture and storage.[3]

Table 1. Sources for CO_2 Emissions in the United States from Combustion of Fossil Fuels

Sources	CO_2 Emissions[a]	Percent of Total
Electricity generation	2,397.3	42%
Transportation	1,887.4	33%
Industrial	845.4	15%
Residential	340.6	6%
Commercial	214.4	4%
Total	**5,685.1**	**100%**

Source: U.S. Environmental Protection Agency (EPA), *Inventory of U.S. Greenhouse Emissions and Sinks: 1990-2007*, Table ES-3; see http://epa.gov/climatechange/emissions/usinventoryreport.html.

a. CO_2 emissions in millions of metric tons for 2007; excludes emissions from U.S. territories.

[1] U.S. Department of Energy, National Energy Technology Laboratory, *Carbon Sequestration Through Enhanced Oil Recovery*, (March, 2008), at http://www.netl.doe.gov/publications/factsheets/program/Prog053.pdf.

[2] U.S. Environmental Protection Agency (EPA), *Inventory of U.S. Greenhouse Emissions and Sinks: 1990-2007*, p. ES-6. The percentage refers to U.S. emissions in 2007; see http://epa.gov/climatechange/emissions/usinventoryreport.html.

[3] Intergovernmental Panel on Climate Change (IPCC) Special Report: *Carbon Dioxide Capture and Storage*, 2005. (Hereafter referred to as IPCC Special Report.)

Congressional interest in CCS, as part of legislation addressing climate change, is growing. In its first month, the 111th Congress passed the American Recovery and Reinvestment Act of 2009 (ARRA), which included $3.4 billion for CCS-related activities. The Omnibus Appropriations Act for 2009 (P.L. 111-8) extended authorization indefinitely for $8 billion in loan guarantees for coal-based power generation and gasification with carbon capture. In the 110th Congress, Division B of P.L. 110-343 (part of the Emergency Economic Stabilization Act of 2008) nearly doubled the aggregate amount of tax credits available for CCS-related projects from $1.65 billion to $3.15 billion. Comprehensive cap-and-trade legislation introduced in the 111th Congress, such as H.R. 2454, also includes provisions for CCS. At issue for Congress is whether the "technology-push" approach of investing in research and development, such as the large influx of funding provided in ARRA, will spur commercial deployment of CCS even without a market demand—created through a price mechanism or regulatory requirement. Even if CCS technology becomes more efficient and cheaper as a result of federal investment in R&D, few companies may have the incentive to install such technology unless they are required to do so.

This report covers only CCS and not other types of carbon sequestration activities whereby CO_2 is removed from the atmosphere and stored in vegetation, soils, or oceans. Forests and agricultural lands store carbon, and the world's oceans exchange huge amounts of CO_2 from the atmosphere through natural processes.[4]

Selected Legislation in the 111th Congress

P.L. 111-5, The American Recovery and Reinvestment Act of 2009

Funding for carbon capture and sequestration technology has increased substantially as a result of enactment of ARRA (P.L. 111-5). In the compromise legislation considered in conference on February 11, 2009, the conferees agreed to provide $3.4 billion through FY2010 for fossil energy research and development within the Department of Energy (DOE). Of that amount, $1.52 billion would be made available for a competitive solicitation for industrial carbon capture and energy efficiency improvement projects, according to the explanatory statement accompanying the legislation. This provision likely refers to a program for large scale demonstration projects that capture CO_2 from a range of industrial sources. A small portion of the $1.52 billion would be allocated for developing innovative concepts for reusing CO_2, according to the explanatory statement. Of the remaining $1.88 billion, $1 billion would be available for fossil energy research and development programs. The explanatory statement did not specify which program or programs would receive funding, however, or how the $1 billion would be allocated. However, on June 12, 2009, Energy Secretary Chu announced that the $1 billion would be used to support a renewed FutureGen facility in Mattoon, IL. Of the remaining $880 million, the conferees agreed to allocate $800 million to the DOE Clean Coal Power Initiative Round III solicitations, which specifically target coal-based systems that capture and sequester, or reuse, CO_2 emissions. Lastly, $50 million would be allocated for site characterization activities in geologic formations (for the

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[4] For more information about carbon sequestration in forests and agricultural lands, see CRS Report RL31432, *Carbon Sequestration in Forests*, by Ross W. Gorte; CRS Report RL33898, *Climate Change: The Role of the U.S. Agriculture Sector and Congressional Action*, by Renée Johnson, and CRS Report R40186, *Biochar: Examination of an Emerging Concept to Mitigate Climate Change*, by Kelsi S. Bracmort. For more information about carbon exchanges between the oceans, atmosphere, and land surface, see CRS Report RL34059, *The Carbon Cycle: Implications for Climate Change and Congress*, by Peter Folger.

storage component of CCS activities), \$20 million for geologic sequestration training and research, and \$10 million for unspecified program activities.

With the announcement that \$1 billion of the ARRA funds would be used to restart FutureGen, nearly all of the \$3.4 billion agreed to by conferees will be used for CCS activities, and would represent a substantial infusion of funding compared to current spending levels. It would also be a large and rapid increase in funding over what DOE spent on CCS cumulatively since FY1997.[5] Moreover, the bulk of DOE's CCS program would shift to the capture component of CCS, unless funding for the storage component increases commensurately in annual appropriations. The large and rapid increase in funding, compared to the magnitude and pace of previous CCS spending, may raise questions about how efficiently the new funding could be used to spur innovation for carbon capture technology.

P.L. 111-8, The Omnibus Appropriations Act, 2009

The Omnibus Appropriations Act for FY2009 restated and made indefinite the existing loan guarantee authority that could be applied to CCS-related activities, originally authorized under Title XVII of the Energy Policy Act of 2005 (EPAct2005, P.L. 109-58, 42 U.S.C. §§16511-16514). Under P.L. 111-8, \$6 billion in loan guarantees is provided for coal-based power generation and industrial gasification activities at retrofitted and new facilities that incorporate CCS or other beneficial uses of carbon. The act provides an additional \$2 billion in loan guarantees for advanced coal gasification.[6]

H.R. 2454, the American Clean Energy and Security Act of 2009

H.R. 2454 (introduced on May 15, 2009, by Representatives Waxman and Markey) has been the primary energy and climate change legislative proposal thus far in the 111th Congress. Subtitle B of H.R. 2454 contains several provisions addressing CCS:[7]

- Section 111 requires the U.S. Environmental Protection Agency (EPA) Administrator to submit a report to Congress, within 120 days of enactment, detailing a unified national strategy for addressing the key legal and regulatory barriers to deployment of commercial-scale carbon capture and sequestration.
- Section 113 amends the Safe Drinking Water Act (SDWA) by directing the EPA Administrator to promulgate regulations for the development, operation, and closure of CO_2 geologic sequestration wells within one year of enactment, and to consider the ongoing SDWA rulemaking regarding these wells. Section 113 would also amend Title VIII of the Clean Air Act and establish a coordinated certification and permitting process for geologic sequestration sites.

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[5] Approximately \$900 million through FY2008 (CRS estimate).

[6] Under Title XIII of EPAct2005, gasification technology means any process that converts a solid or liquid product from coal, petroleum residue, biomass, or other materials, which are recovered for their energy or feedstock value, into a synthesis gas (composed primarily of carbon monoxide and hydrogen) for direct use in the production of energy or for subsequent conversion to another product.

[7] For a more detailed description and analysis of Subtitle B and all other provisions of H.R. 2454, see CRS Report R40643, *Greenhouse Gas Legislation: Summary and Analysis of H.R. 2454 as Reported by the House Committee on Energy and Commerce*, coordinated by Mark Holt and Gene Whitney.

- Section 114 authorizes a Carbon Storage Research Corporation to establish and administer a program to accelerate the commercial availability of CO_2 capture and storage technologies and methods by awarding grants, contracts, and financial assistance to electric utilities, academic institutions, and other eligible entities. If established, the corporation would levy an assessment on distribution utilities for all fossil fuel-based electricity delivered to retail customers, and would adjust the assessment rates to generate between $1.0 and $1.1 billion per year.
- Section 115 amends Title VII of the Clean Air Act (CAA) to require that the EPA Administrator promulgate regulations to distribute emission allowances to support the commercial deployment of carbon capture and sequestration technologies in both electric power generation and industrial operations.
- Section 116 amends Title VIII of the CAA by adding performance standards for new coal-fired power plants and, in some instances, for existing plants retrofitted with carbon capture and sequestration technology.

S. 1013, the Department of Energy Carbon Capture and Sequestration Program Amendments Act of 2009

S. 1013 (introduced May 7, 2009, by Senator Bingaman and others) authorizes DOE to carry out a program of up to 10 "large-scale" projects that demonstrate all aspects of CCS: capture, transportation, injection, monitoring, and long-term storage of CO_2 from industrial facilities. The legislation defines "large-scale" as the injection of at least 1 million tons of CO_2 per year into a geologic formation. The Secretary of Energy is authorized to enter into cooperative agreements, under a competitive selection process, with applicants who provide sufficient information about the long-term geologic storage capacity of the site, possess or have interests in the land, and have or can reasonably be expected to obtain the necessary permits for the project.

The legislation requires a successful applicant to maintain financial protection in a form and amount acceptable to the DOE Secretary, EPA Administrator, or Secretary with jurisdiction over the land. In addition, the operator of the site must meet post-closure criteria established in the legislation, and continual compliance with criteria for at least 10 consecutive years after the plume of injected CO_2 has come into "equilibrium" with the geologic formation. The legislation does not define "equilibrium" specifically, but includes the following as necessary conditions:

- no change in the project footprint—the extent of the plume and area of elevated subsurface;
- no leakage of CO_2 or displaced fluids;
- no expectation of future migration of CO_2 or displaced fluids that could lead to leakage;
- injection wells plugged and abandoned in compliance with federal and state requirements.

If the operator meets all the requirements, and is not guilty of gross negligence and intentional misconduct, the Secretary of Energy may indemnify the operator from any liability that exceeds the amount of liability covered through financial protection maintained by the operator as required by the legislation.

Under S. 1013, some of the projects may be sited on federal lands in a manner consistent with applicable laws and land management plans under the relevant land management agency. The Secretary with jurisdiction over the land would also take into account the framework for geological sequestration on public land prepared in accordance with §714 of P.L. 110-140.[8]

The legislation also allows the Secretary of Energy to accept title to, or accept transfer of, administrative jurisdiction from another federal agency for land necessary for the monitoring, remediation, or long-term stewardship of the project site.

Capturing CO_2

The first step in CCS is to capture CO_2 at the source and produce a concentrated stream for transport and storage. Currently, three main approaches are available to capture CO_2 from large-scale industrial facilities or power plants: (1) post-combustion capture, (2) pre-combustion capture, and (3) oxy-fuel combustion capture. For power plants, current commercial CO_2 capture systems could operate at 85%-95% capture efficiency,[9] but such techniques for capturing CO_2 have not yet been applied to large power plants (e.g., 500 megawatts or more).[10]

Application of these technologies to power plants generating several hundred megawatts of electricity has not yet been demonstrated.[11] Also, up to 80% of the total costs for CCS may be associated with the capture phase of the CCS process.[12]

Post-Combustion Capture

This process involves extracting CO_2 from the flue gas following combustion of fossil fuels or biomass. Several commercially available technologies, some involving absorption using chemical solvents, can in principle be used to capture large quantities of CO_2 from flue gases. U.S. commercial electricity-generating plants currently do not capture large volumes of CO_2 because they are not required to and there are no economic incentives to do so. Nevertheless, the post-combustion capture process includes proven technologies that are commercially available today. **Figure 1** shows a simplified illustration of this process.

[8] The framework was released in a report on June 3, 2009 and is available at http://www.doi.gov/news/09_News_Releases/EISA_Sec._714_Report_to_Congress_V12_Final.pdf.

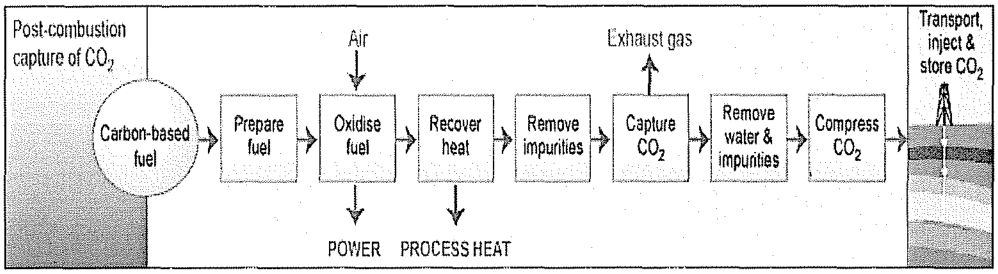
[9] IPCC Special Report, p. 107.

[10] Ibid., p. 25.

[11] The Schwarze-Pumpe 30 MW oxy-fuel pilot plant in Germany has been operating since mid-2008. The captured CO_2 will be used for enhanced gas recovery at a nearby natural gas field. See http://www.vattenfall.com/www/co2_en/co2_en/Gemeinsame_Inhalte/DOCUMENT/388963co2x/401837co2x/P0277108.pdf.

[12] Steve Furnival, reservoir engineer at Senergy, Ltd., "Burying Climate Change for Good," *Physics World*; see http://physicsworld.com/cws/article/print/25727.

Figure 1. Simplified Illustration of Post-Combustion CO_2 Capture



Source: Scottish Centre for Carbon Storage. Figure available at http://www.geos.ed.ac.uk/sccs/capture/precombustion.html

Pre-Combustion Capture

This process separates CO_2 from the fuel by combining the fuel with air and/or steam to produce hydrogen for combustion and a separate CO_2 stream that could be stored. **Figure 2** shows a simplified illustration of this process. The most common technologies today use steam reforming, in which steam is employed to extract hydrogen from natural gas.[13] In the absence of a requirement or economic incentives, pre-combustion technologies have not been used for some power systems, such as natural gas combined-cycle power plants.

Currently, a requirement for the pre-combustion capture of CO_2 is the use of Integrated Gasification Combined-Cycle (IGCC) technology to generate electricity.[14] There are currently four commercial IGCC plants worldwide (two in the United States) each with a capacity of about 250 MW. The technology has yet to make a major breakthrough in the U.S. market because its potential superior environmental performance is currently not required under the Clean Air Act, and, thus, its higher costs can not be justified.

Pre-combustion capture of CO_2 is viewed by some as a necessary requirement for coal-to-liquid fuel processes, whereby coal can be converted through a catalyzed chemical reaction to a variety of liquid hydrocarbons. Concerns have been raised because the coal-to-liquid process releases CO_2, and the end product—the liquid fuel itself—further releases CO_2 when combusted. Pre-combustion capture during the coal-to-liquid process would reduce the total amount of CO_2 emitted, although CO_2 would still be released during combustion of the liquid fuel used for transportation or electricity generation.[15]

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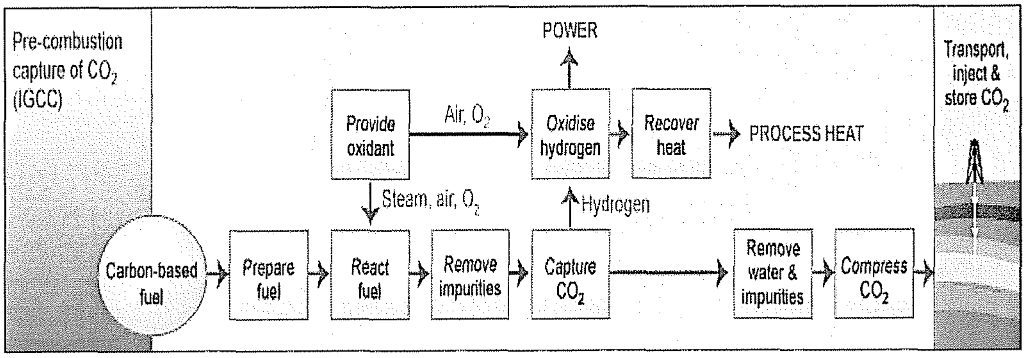
[13] IPCC Special Report, p. 130.

[14] IGCC is an electric generating technology in which pulverized coal is not burned directly but mixed with oxygen and water in a high-pressure gasifier to make "syngas," a combustible fluid that is then burned in a conventional combined-cycle arrangement to generate power.

[15] For more information on the coal-to-liquid process and issues for Congress, see CRS Report RL34133, *Fischer-Tropsch Fuels from Coal, Natural Gas, and Biomass: Background and Policy*, by Anthony Andrews and Jeffrey Logan.

Figure 2. Simplified Illustration of Pre-Combustion CO_2 Capture

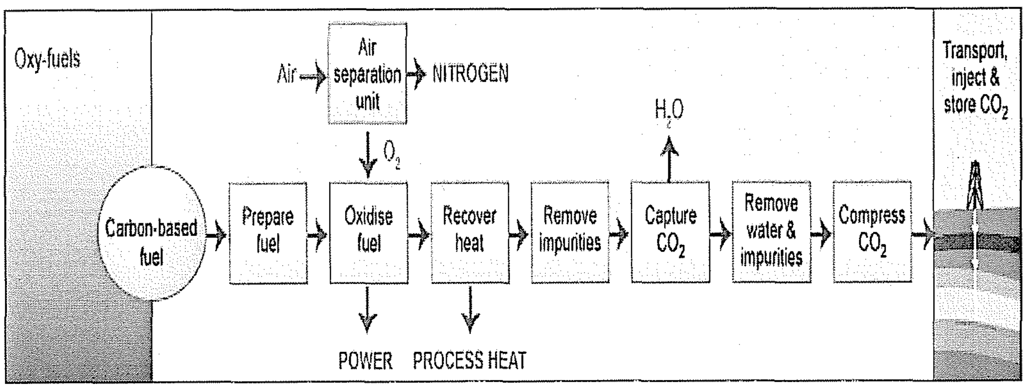


Source: Scottish Centre for Carbon Storage. Figure available at http://www.geos.ed.ac.uk/sccs/capture/precombustion.html.

Oxy-Fuel Combustion Capture

This process uses oxygen instead of air for combustion and produces a flue gas that is mostly CO_2 and water, which are easily separable, after which the CO_2 can be compressed, transported, and stored. This technique is still considered developmental, in part because temperatures of pure oxygen combustion (about 3,500° C) are far too high for typical power plant materials.[16] The details of this "oxy-fuel" process are still being refined, but generally, from the boiler the exhaust gas is cleaned of conventional pollutants (SO_2, NOx, and particulates) and some of the gases can be recycled to the boiler to control the higher temperature resulting from coal combustion with pure oxygen. The rest of the gas stream is sent for further purification and compression in preparation for transport and/or storage.[17] Depending on site-specific conditions, oxy-fuel could be retrofitted onto existing boilers. **Figure 3** shows a simplified illustration of this process.

Figure 3. Simplified Illustration of Oxy-Fuel CO_2 Capture



Source: Scottish Centre for Carbon Storage. Figure available at http://www.geos.ed.ac.uk/sccs/capture/oxyfuel.html.

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[16] IPCC Special Report, p. 122.

[17] Massachusetts Institute of Technology, *The Future of Coal: Options for a Carbon-Constrained World*, 2007, pp. 30-31. Hereafter referred to as .MIT, *The Future of Coal.*

Transportation

Pipelines are the most common method for transporting CO_2 in the United States. Currently, more than 5,800 kilometers (about 3,600 miles) of pipeline transport CO_2 in the United States, predominately to oil and gas fields, where it is used for enhanced oil recovery (EOR).[18] Transporting CO_2 in pipelines is similar to transporting petroleum products like natural gas and oil; it requires attention to design, monitoring for leaks, and protection against overpressure, especially in populated areas.[19]

Using ships may be feasible when CO_2 must be transported over large distances or overseas. Ships transport CO_2 today, but at a small scale because of limited demand. Liquefied natural gas, propane, and butane are routinely shipped by marine tankers on a large scale worldwide. Rail cars and trucks can also transport CO_2, but this mode would probably be uneconomical for large-scale CCS operations.

Costs for pipeline transport vary, depending on construction, operation and maintenance, and other factors, including right-of-way costs, regulatory fees, and more. The quantity and distance transported will mostly determine costs, which will also depend on whether the pipeline is onshore or offshore, the level of congestion along the route, and whether mountains, large rivers, or frozen ground are encountered. Shipping costs are unknown in any detail, however, because no large-scale CO_2 transport system (in millions of metric tons of CO_2 per year, for example) is operating. Ship costs might be lower than pipeline transport for distances greater than 1,000 kilometers and for less than a few million metric tons of CO_2 ($MtCO_2$)[20] transported per year.[21]

Even though regional CO_2 pipeline networks currently operate in the United States for enhanced oil recovery (EOR), developing a more expansive network for CCS could pose numerous regulatory and economic challenges. Some of these include questions about pipeline network requirements, economic regulation, utility cost recovery, regulatory classification of CO_2 itself, and pipeline safety.[22]

Sequestration in Geological Formations

Three main types of geological formations are being considered for carbon sequestration: (1) depleted oil and gas reservoirs, (2) deep saline reservoirs, and (3) unmineable coal seams. In each case, CO_2 would be injected in a supercritical state—a relatively dense liquid—below ground into a porous rock formation that holds or previously held fluids. By injecting CO_2 at depths greater than 800 meters in a typical reservoir, the pressure keeps the injected CO_2 in a

[18] U.S. Department of Transportation, National Pipeline Mapping System database (June 2005), at https://www.npms.phmsa.dot.gov/. By comparison, nearly 800,000 kilometers (500,000 miles) of pipeline operates to convey natural gas and hazardous liquids in the United States.

[19] IPCC Special Report, p. 181.

[20] One metric ton of CO_2 equivalent is written as 1 tCO_2; one million metric tons is written as 1 $MtCO_2$; one billion metric tons is written as 1 $GtCO_2$.

[21] IPCC Special Report, p. 31.

[22] These issues are discussed in more detail in CRS Report RL33971, *Carbon Dioxide (CO2) Pipelines for Carbon Sequestration: Emerging Policy Issues*, by Paul W. Parfomak and Peter Folger, and CRS Report RL34316, *Pipelines for Carbon Dioxide (CO2) Control: Network Needs and Cost Uncertainties*, by Paul W. Parfomak and Peter Folger.

supercritical state and thus less likely to migrate out of the geological formation. Injecting CO_2 into deep geological formations uses existing technologies that have been primarily developed and used by the oil and gas industry, and that could potentially be adapted for long-term storage and monitoring of CO_2. Other underground injection applications in practice today, such as natural gas storage, deep injection of liquid wastes, and subsurface disposal of oil-field brines, can also provide valuable experience and information for sequestering CO_2 in geological formations.[23]

The storage capacity for CO_2 storage in geological formations is potentially huge if all the sedimentary basins in the world are considered.[24] The suitability of any particular site, however, depends on many factors including proximity to CO_2 sources and other reservoir-specific qualities like porosity, permeability, and potential for leakage.

Oil and Gas Reservoirs

Pumping CO_2 into oil and gas reservoirs to boost production (enhanced oil recovery, or EOR) is practiced in the petroleum industry today. The United States is a world leader in this technology, and oil and gas operators inject approximately 48 $MtCO_2$ underground each year to help recover oil and gas resources.[25] Most of the CO_2 used for EOR in the United States comes from naturally occurring geologic formations, however, not from industrial sources.

Carbon dioxide can be stored onshore or offshore; to date, most CO_2 projects associated with EOR are onshore, with the bulk of U.S. activities in west Texas. The advantage of using this technique for long-term CO_2 storage is that sequestration costs can be partially offset by revenues from oil and gas production. Carbon dioxide can also be injected into oil and gas reservoirs that are completely depleted, which would serve the purpose of long-term sequestration, but without any offsetting benefit from oil and gas production.

The In Salah and Weyburn Projects

The In Salah Project in Algeria is the world's first large-scale effort to store CO_2 in a natural gas reservoir.[26] At In Salah, CO_2 is separated from the produced natural gas and then reinjected into the same formation. Approximately 17 $MtCO_2$ are planned to be captured and stored over the lifetime of the project.

The Weyburn Project in south-central Canada uses CO_2 produced from a coal gasification plant in North Dakota for EOR, injecting up to 5,000 tCO_2 per day into the formation and recovering oil.[27] Approximately 20 $MtCO_2$ are expected to remain in the formation over the lifetime of the project.

[23] IPCC Special Report, p. 31.

[24] Sedimentary basins refer to natural large-scale depressions in the Earth's surface that are filled with sediments and fluids and are therefore potential reservoirs for CO_2 storage.

[25] Data from 2006. See DOE, National Energy Technology Laboratory, *Carbon Sequestration Through Enhanced Oil Recovery*, (March 2008), at http://www.netl.doe.gov/publications/factsheets/program/Prog053.pdf..

[26] IPCC Special Report, p. 203.

[27] Ibid., p. 204.

Advantages and Disadvantages

Depleted or abandoned oil and gas fields, especially in the United States, are considered prime candidates for CO_2 storage for several reasons:

- oil and gas originally trapped did not escape for millions of years, demonstrating the structural integrity of the reservoir;
- extensive studies for oil and gas typically have characterized the geology of the reservoir;
- computer models have often been developed to understand how hydrocarbons move in the reservoir, and the models could be applied to predicting how CO_2 could move; and
- infrastructure and wells from oil and gas extraction may be in place and might be used for handling CO_2 storage.

Some of these features could also be disadvantages to CO_2 sequestration. Wells that penetrate from the surface to the reservoir could be conduits for CO_2 release if they are not plugged properly. Care must be taken not to overpressure the reservoir during CO_2 injection, which could fracture the caprock—the part of the formation that formed a seal to trap oil and gas—and subsequently allow CO_2 to escape. Also, shallow oil and gas fields (those less than 800 meters deep, for example) may be unsuitable because CO_2 may form a gas instead of a denser liquid and could escape to the surface more easily. In addition, oil and gas fields that are suitable for EOR may not necessarily be located near industrial sources of CO_2. Costs to construct pipelines to connect sources of CO_2 with oil and gas fields may, in part, determine whether an EOR operation using industrial sources of CO_2 is feasible.

Although the United States injects nearly 50 $MtCO_2$ underground each year for the purposes of EOR, that amount represents approximately 2% of the CO_2 emitted from fossil fuel electricity generation alone. The sheer volume of CO_2 envisioned for CCS as a climate mitigation option is overwhelming compared to the amount of CO_2 used for EOR. It may be that EOR will increase in the future, depending on economic, regulatory, and technical factors, and more CO_2 will be sequestered as a consequence. It is also likely that EOR would only account for a small fraction of the total amount of CO_2 injected underground in the future if CCS becomes a significant component in an overall scheme to substantially reduce CO_2 emissions to the atmosphere.

Deep Saline Reservoirs

Some rocks in sedimentary basins contain saline fluids—brines or brackish water unsuitable for agriculture or drinking. As with oil and gas, deep saline reservoirs can be found onshore and offshore; in fact, they are often part of oil and gas reservoirs and share many characteristics. The oil industry routinely injects brines recovered during oil production into saline reservoirs for disposal.[28] Using suitably deep saline reservoirs for CO_2 sequestration has several advantages: (1) they are more widespread in the United States than oil and gas reservoirs and thus have greater probability of being close to large point sources of CO_2; and (2) saline reservoirs have potentially the largest reservoir capacity of the three types of geologic formations.

[28] DOE Office of Fossil Energy; see http://www.fossil.energy.gov/programs/sequestration/geologic/index.html.

The Sleipner Project

The Sleipner Project in the North Sea is the first commercial-scale operation for sequestering CO_2 in a deep saline reservoir. The Sleipner project has been operating since 1996, and it injects and stores approximately 2,800 tCO_2 per day, or about 1 $MtCO_2$ per year.[29] Carbon dioxide is separated from natural gas production at the nearby Sleipner West Gas Field, compressed, and then injected 800 meters below the seabed of the North Sea into the Utsira formation, a sandstone reservoir 200-250 meters (650-820 feet) thick containing saline fluids. Monitoring has indicated the CO_2 has not leaked from the saline reservoir, and computer simulations suggest that the CO_2 will eventually dissolve into the saline water, reducing the potential for leakage in the future.

Large CO_2 sequestration projects, similar to Sleipner, are being planned in western Australia (the Gorgon Project)[30] and in the Barents Sea (the Snohvit Project),[31] that would inject 10,000 and 2,000 tCO_2 per day respectively, when at full capacity. Similar to the Sleipner operation, both projects plan to strip CO_2 from produced natural gas and inject it into deep saline formations for permanent storage. According to company sources, the Snohvit Project began capturing and sequestering CO_2 in April 2008.[32]

Advantages and Disadvantages

Although deep saline reservoirs potentially have huge capacity to store CO_2, estimates of lower and upper capacities vary greatly, reflecting a higher degree of uncertainty in how to measure storage capacity.[33] Actual storage capacity may have to be determined on a case-by-case basis.

In addition, some studies have pointed out potential problems with maintaining the integrity of the reservoir because of chemical reactions following CO_2 injection. Injecting CO_2 can acidify (lower the pH of) the fluids in the reservoir, dissolving minerals such as calcium carbonate, and possibly increasing permeability. Increased permeability could allow CO_2-rich fluids to escape the reservoir along new pathways and contaminate aquifers used for drinking water.

In an October 2004 experiment, researchers injected 1,600 tCO_2 1,500 meters deep into the Frio Formation—a saline reservoir containing oil and gas—along the Gulf Coast near Dayton, TX, to test its performance for CO_2 sequestration and storage.[34] Test results indicated that calcium carbonate and other minerals rapidly dissolved following injection of the CO_2. The researchers also measured increased concentrations of iron and manganese in the reservoir fluids, suggesting that the dissolved minerals had high concentrations of those metals. The results raised the possibility that toxic metals and other compounds might be liberated if CO_2 injection dissolved minerals that held high concentrations of those substances.

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[29] International Energy Agency (IEA) Greenhouse Gas R&D Programme, RD&D Projects Database, at http://www.co2captureandstorage.info/project_specific.php?project_id=26.

[30] Ibid, at http://www.co2captureandstorage.info/project_specific.php?project_id=122.

[31] Ibid, at http://www.co2captureandstorage.info/project_specific.php?project_id=35.

[32] See http://www.statoilhydro.com/AnnualReport2008/en/Sustainability/Climate/Pages/5-3-2-4_Sn%C3%B8hvitCCS.aspx.

[33] IPCC Special Report, p. 223.

[34] Y. K. Kharaka, et al., "Gas-water interactions in the Frio Formation following CO_2 injection: implications for the storage of greenhouse gases in sedimentary basins," *Geology*, v. 34, no. 7 (July, 2006), pp. 577-580.

Another concern is whether the injected fluids, with pH lowered by CO_2, would dissolve cement used to seal the injection wells that pierce the formation from the ground surface. Leaky injection wells could then also become pathways for CO_2-rich fluids to migrate out of the saline formation and contaminate fresher groundwater above. Approximately six months after the injection experiment at the Dayton site, however, researchers did not detect any leakage upwards into the overlying formation, suggesting that the integrity of the saline reservoir formation remained intact at that time.

Preliminary results from a second injection test in the Frio Formation appear to replicate results from the first experiment, indicating that the integrity of the saline reservoir formation remained intact, and that the researchers could detect migration of the CO_2-rich plume from the injection point to the observation well in the target zone. These results suggest to the researchers that they have the data and experimental tools to move to the next, larger-scale phase of CO_2 injection experiments.[35]

Unmineable Coal Seams

According to DOE, nearly 90% of U.S. coal resources are not mineable with current technology, because the coal beds are not thick enough, the beds are too deep, or the structural integrity of the coal bed[36] is inadequate for mining. Even if they cannot be mined, coal beds are commonly permeable and can trap gases, such as methane, which can be extracted (a resource known as coal bed methane, or CBM). Methane and other gases are physically bound (adsorbed) to the coal. Studies indicate that CO_2 binds even more tightly to coal than methane.[37] Carbon dioxide injected into permeable coal seams could displace methane, which could be recovered by wells and brought to the surface, providing a source of revenue to offset the costs of CO_2 injection.

Advantages and Disadvantages

Unmineable coal seam injection projects would need to assess several factors in addition to the potential for CBM extraction. These include depth, permeability, coal bed geometry (a few thick seams, not several thin seams), lateral continuity and vertical isolation (less potential for upward leakage), and other considerations. Once CO_2 is injected into a coal seam, it would likely remain there unless the seam is depressurized or the coal is mined. Also, many unmineable coal seams in the United States are located relatively near electricity-generating facilities, which could reduce the distance and cost of transporting CO_2 from large point sources to storage sites.

Not all types of coal beds are suitable for CBM extraction. Without the coal bed methane resource, the sequestration process would be less economically attractive. Also, the displaced methane would need to be combusted or captured because methane itself is a more potent greenhouse gas than CO_2. No commercial CO_2 injection and sequestration projects in coal beds are currently underway.

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[35] Personal communication with Dr. Susan D. Hovorka, principal investigator for the Frio Project, Bureau of Economic Geology, Jackson School of Geosciences, University of Texas at Austin, Aug. 22, 2007.

[36] *Coal bed* and *coal seam* are interchangeable terms.

[37] IPCC Special Report, p. 217.

Without ongoing commercial experience, storing CO_2 in coal seams has significant uncertainties compared to the other two types of geological storage discussed. According to IPCC, unmineable coal seams have the smallest potential capacity for storing CO_2 globally compared to oil and gas fields or deep saline formations. DOE indicates that unmineable coal seams in the United States, however, have more potential capacity than oil and gas fields for storing CO_2. The discrepancy could represent the relatively abundant U.S. coal reserves compared to other regions in the world, or it might also indicate the level of uncertainty in estimating the CO_2 storage capacity in unmineable coal seams.

Geological Storage Capacity for CO_2 in the United States

According to the DOE 2008 Carbon Sequestration Atlas,[38] at least one of each of these three types of potential CO_2 reservoirs occurs across most of the United States in relative proximity to many large point sources of CO_2, such as fossil fuel power plants or cement plants. The 2008 Carbon Sequestration Atlas updates the 2007 version, and contains a substantial expansion of the estimated storage capacity for oil and gas reservoirs and especially for deep saline formations compared to 2007 estimates. **Table 2** shows the 2008 estimates and compares them to estimates from the 2007 version.

The Carbon Sequestration Atlas was compiled from estimates of geological storage capacity made by seven separate regional partnerships (government-industry collaborations fostered by DOE) that each produced estimates for different regions of the United States and parts of Canada. According to DOE, geographical differences in fossil fuel use and sequestration potential across the country led to a regional approach to assessing CO_2 sequestration potential.[39] The Carbon Sequestration Atlas reflects some of the regional differences; for example, not all of the regional partnerships identified unmineable coal seams as potential CO_2 reservoirs. Other partnerships identified geological formations unique to their regions—such as organic-rich shales in the Illinois Basin, or flood basalts in the Columbia River Plateau—as other types of possible reservoirs for CO_2 storage.

Table 2 indicates a lower and upper range for sequestration potential in deep saline formations and for unmineable coal seams, but only a single estimate for oil and gas fields. The 2007 Carbon Sequestration Atlas explained that a range of sequestration capacity for oil and gas reservoirs is not provided—in contrast to deep saline formations and coal seams—because of the relatively good understanding of oil and gas field volumetrics.[40] Although it is widely accepted that oil and gas reservoirs are better understood, primarily because of the long history of oil and gas exploration and development, it seems unlikely that the capacity for CO_2 storage in oil and gas formations is known to the level of precision stated in the 2008 Carbon Sequestration Atlas. It is likely that the estimate of 138 $GtCO_2$ shown in **Table 2** may change, for example, pending the results of large-scale CO_2 injection tests in oil and gas fields.

[38] U.S. Dept. of Energy, National Energy Technology Laboratory, *2008 Carbon Sequestration Atlas of the United States and Canada*, 2[nd] ed. (November 2008), 140 pages. Hereafter referred to as the 2008 Carbon Sequestration Atlas. See http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasII/.

[39] 2008 Carbon Sequestration Atlas, p. 8.

[40] 2007 Carbon Sequestration Atlas, p. 12.

Table 2. Geological Sequestration Potential for the United States and Parts of Canada

(comparing 2008 and 2007 estimates, $GtCO_2$)

Reservoir type	Lower estimate (2008)	Lower estimate (2007)	% change	Upper estimate (2008)	Upper estimate (2007)	% change
Oil and gas fields	138	82.4	+67%	—	—	—
Deep saline formations	3,297	919.0	+259%	12,618	3,378.0	+274%
Unmineable coal seams	157	156.1	+0.6%	178	183.5	-3.0%

Source: 2008 and 2007 Carbon Sequestration Atlases.

Each partnership produced its own estimates of reservoir capacity, and some observers have raised the issue of consistency among estimates across the regions. The Energy Independence and Security Act of 2007 (EISA, P.L. 110-140) directed the Department of the Interior (DOI) to develop a single methodology for an assessment of the national potential for geologic storage of carbon dioxide. EISA directed the U.S. Geological Survey (USGS) within DOI to complete an assessment of the national capacity for CO_2 storage in accordance with the methodology. The law gives the USGS two years following publication of the methodology to complete the national assessment. According to DOE, the USGS effort will allow refinement of the estimates provided in the 2008 Carbon Sequestration Atlas, and will incorporate uncertainty in the capacity estimates.[41] The DOE Sequestration Atlas should probably be considered an evolving assessment of U.S. reservoir capacity for CO_2 storage.

Deep Ocean Sequestration

The world's oceans contain approximately 50 times the amount of carbon stored in the atmosphere and nearly 10 times the amount stored in plants and soils.[42] The oceans today take up—act as a net sink for—approximately 1.7 $GtCO_2$ per year. About 45% of the CO_2 released from fossil fuel combustion and land use activities during the 1990s has remained in the atmosphere, while the remainder has been taken up by the oceans, vegetation, or soils on the land surface.[43] Without the ocean sink, atmospheric CO_2 concentration would be increasing more rapidly. Ultimately, the oceans could store more than 90% of all the carbon released to the atmosphere by human activities, but the process takes thousands of years.[44] The ocean's capacity

[41] 2008 Carbon Sequestration Atlas, p. 23.

[42] Christopher L. Sabine et al., "Current Status and Past Trends of the Global Carbon Cycle," in C. B. Field and M. R. Raupach, eds., *The Global Carbon Cycle: Integrating Humans, Climate, and the Natural World* (Washington, DC: Island Press, 2004), pp. 17-44.

[43] 2007 IPCC Working Group I Report, pp. 514-515.

[44] CO_2 forms carbonic acid when dissolved in water. Over time, the solid calcium carbonate ($CaCO_3$) on the seafloor will react with (neutralize) much of the carbonic acid that entered the oceans as CO_2 from the atmosphere. See David Archer et al., "Dynamics of fossil fuel CO_2 neutralization by marine $CaCO_3$," *Global Biogeochemical Cycles*, vol. 12, no. 2 (June 1998): pp. 259-276.

to absorb atmospheric CO_2 may change, however, and possibly even decrease in the future.[45] Also, studies indicate that, as more CO_2 enters the ocean from the atmosphere, the surface waters are becoming more acidic.[46]

Advantages and Disadvantages

Although the surface of the ocean is becoming more concentrated with CO_2, the surface waters and the deep ocean waters generally mix very slowly, on the order of decades to centuries. Injecting CO_2 directly into the deep ocean would take advantage of the slow rate of mixing, allowing the injected CO_2 to remain sequestered until the surface and deep waters mix and CO_2 concentrations equilibrate with the atmosphere. What happens to the CO_2 would depend on how it is released into the ocean, the depth of injection, and the temperature of the seawater.

Carbon dioxide injected at depths shallower than 500 meters typically would be released as a gas, and would rise towards the surface. Most of it would dissolve into seawater if the injected CO_2 gas bubbles were small enough.[47] At depths below 500 meters, CO_2 can exist as a liquid in the ocean, although it is less dense than seawater. After injection below 500 meters, CO_2 would also rise, but an estimated 90% would dissolve in the first 200 meters. Below 3,000 meters in depth, CO_2 is a liquid and is denser than seawater; the injected CO_2 would sink and dissolve in the water column or possibly form a CO_2 pool or lake on the sea bottom. Some researchers have proposed injecting CO_2 into the ocean bottom sediments below depths of 3,000 meters, and immobilizing the CO_2 as a dense liquid or solid CO_2 hydrate.[48] Deep storage in ocean bottom sediments, below 3,000 meters in depth, might potentially sequester CO_2 for thousands of years.[49]

The potential for ocean storage of captured CO_2 is huge, but environmental impacts on marine ecosystems and other issues may determine whether large quantities of captured CO_2 will ultimately be stored in the oceans. Also, deep ocean storage is in a research stage, and the effects of scaling up from small research experiments, using less than 100 liters of CO_2,[50] to injecting several $GtCO_2$ into the deep ocean are unknown.

Injecting CO_2 into the deep ocean would change ocean chemistry, locally at first, and assuming that hundreds of $GtCO_2$ were injected, would eventually produce measurable changes over the entire ocean.[51] The most significant and immediate effect would be the lowering of pH, increasing the acidity of the water. A lower pH may harm some ocean organisms, depending on the magnitude of the pH change and the type of organism. Actual impacts of deep sea CO_2

[45] One study, for example, suggests that the efficiency of the ocean sink has been declining at least since 2000; see Josep G. Canadell et al., "Contributions to accelerating atmospheric CO_2 growth from economic activity, carbon intensity, and efficiency of natural sinks," *Proceedings of the National Academy of Sciences*, vol. 104, no. 47 (Nov. 20, 2007), pp. 18866-18870.

[46] For more information on ocean acidification, see CRS Report R40143, *Ocean Acidification*, by Eugene H. Buck and Peter Folger.

[47] IPCC Special Report, p. 285.

[48] A CO_2 hydrate is a crystalline compound formed at high pressures and low temperatures by trapping CO_2 molecules in a cage of water molecules.

[49] K. Z. House, et al., "Permanent carbon dioxide storage in deep-sea sediments," *Proceedings of the National Academy of Sciences*, vol. 103, no. 33 (Aug. 15, 2006): pp. 12291-12295.

[50] P. G. Brewer, et al., "Deep ocean experiments with fossil fuel carbon dioxide: creation and sensing of a controlled plume at 4 km depth," *Journal of Marine Research*, vol. 63, no. 1 (2005): p. 9-33.

[51] IPCC Special Report, p. 279.

sequestration are largely unknown, however, because scientists know very little about deep ocean ecosystems.[52]

Environmental concerns led to the cancellation of the largest planned experiment to test the feasibility of ocean sequestration in 2002. A scientific consortium had planned to inject 60 tCO_2 into water over 800 meters deep near the Kona coast on the island of Hawaii. Environmental organizations opposed the experiment on the grounds that it would acidify Hawaii's fishing grounds, and that it would divert attention from reducing greenhouse gas emissions.[53] A similar but smaller project with plans to release more than 5 tCO_2 into the deep ocean off the coast of Norway, also in 2002, was cancelled by the Norway Ministry of the Environment after opposition from environmental groups.[54]

Mineral Carbonation

Another option for sequestering CO_2 produced by fossil fuel combustion involves converting CO_2 to solid inorganic carbonates, such as $CaCO_3$ (limestone), using chemical reactions. When this process occurs naturally it is known as "weathering" and takes place over thousands or millions of years. The process can be accelerated by reacting a high concentration of CO_2 with minerals found in large quantities on the Earth's surface, such as olivine or serpentine.[55] Mineral carbonation has the advantage of sequestering carbon in solid, stable minerals that can be stored without risk of releasing carbon to the atmosphere over geologic time scales.

Mineral carbonation involves three major activities: (1) preparing the reactant minerals—mining, crushing, and milling—and transporting them to a processing plant, (2) reacting the concentrated CO_2 stream with the prepared minerals, and (3) separating the carbonate products and storing them in a suitable repository.

Advantages and Disadvantages

Mineral carbonation is well understood and can be applied at small scales, but is at an early phase of development as a technique for sequestering large amounts of captured CO_2. Large volumes of silicate oxide minerals are needed, from 1.6 to 3.7 metric tons of silicates per tCO_2 sequestered. Thus, a large-scale mineral carbonation process needs a large mining operation to provide the reactant minerals in sufficient quantity.[56] Large volumes of solid material would also be produced, between 2.6 and 4.7 metric tons of materials per tCO_2 sequestered, or 50%-100% more material to be disposed of by volume than originally mined. Because mineral carbonation is in the research and experimental stage, estimating the amount of CO_2 that could be sequestered by this technique is difficult.

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[52] Ibid., p. 298.

[53] Virginia Gewin, "Ocean carbon study to quit Hawaii," *Nature*, vol. 417 (June 27, 2002): p. 888.

[54] Jim Giles, "Norway sinks ocean carbon study," *Nature*, vol. 419 (Sept. 5, 2002): p. 6.

[55] Serpentine and olivine are silicate oxide minerals—combinations of the silica, oxygen, and magnesium—that react with CO_2 to form magnesium carbonates. Wollastonite, a silica oxide mineral containing calcium, reacts with CO_2 to form calcium carbonate (limestone). Magnesium and calcium carbonates are stable minerals over long time scales.

[56] IPCC Special Report, p. 40.

One possible geological reservoir for CO_2 storage—major flood basalts[57] such as those on the Columbia River Plateau—is being explored for its potential to react with CO_2 and form solid carbonates in situ (in place). Instead of mining, crushing, and milling the reactant minerals, as discussed above, CO_2 would be injected directly into the basalt formations and would react with the rock over time and at depth to form solid carbonate minerals. Large and thick formations of flood basalts occur globally, and many have characteristics—such as high porosity and permeability—that are favorable to storing CO_2. Those characteristics, combined with tendency of basalt to react with CO_2, could result in a large-scale conversion of the gas into stable, solid minerals that would remain underground for geologic time. One of the DOE regional carbon sequestration partnerships is exploring the possibility for using Columbia River Plateau flood basalts for storing CO_2; however, investigations are in a preliminary stage.[58]

Costs for CCS

Cost estimates for CCS typically present a range of values and depend on many variables, such as the type of capture technology (post-combustion, pre-combustion, oxy-fuel), whether the plant represents new construction or is a retrofit to an existing plant, whether the CCS project is in a demonstration or a commercial stage, and a variety of other factors. Part of the difficulty in estimating costs is the lack of any operating, commercial-scale electricity-generating power plants that capture and sequester their CO_2 emissions. Thus, there are no real-world examples to draw from. In addition, there is neither a market price for CO_2 emitted nor a regulatory requirement to capture CO_2—a market demand—which would likely shape cost estimates. All observers, however, agree that installing CO_2 capture technology will increase the cost of generating electricity from fossil fuel power plants. As a result, few companies are likely to commit to the extra expense of installing technology to capture CO_2, or installing the infrastructure to transport and store it, until they are required to do so.

Despite these challenges, several studies have estimated costs for CCS, in the likelihood that desire for lower CO_2 emissions and continued demand for electricity from fossil fuel power plants converge and foster development and deployment of CCS. According to one DOE estimate, sequestration costs for capture, transport, and storage range from $27 to $82 per tCO_2 emissions avoided using present technology.[59] In a 2007 study, MIT estimated how much the cost of generating electricity would increase if CO_2 capture technology were installed, both for new plants and for retrofits of existing plants. **Table 3** shows the MIT estimates.

[57] Flood basalts are vast expanses of solidified lava, commonly containing olivine, that erupted over large regions in several locations around the globe. In addition to the Columbia River Plateau flood basalts, other well-known flood basalts include the Deccan Traps in India and the Siberian Traps in Russia.

[58] 2008 Carbon Sequestration Atlas, p. 35.

[59] Equivalent to $100 to $300 per metric ton of carbon emissions avoided; see http://www.fossil.energy.gov/programs/sequestration/overview.html.

Table 3. Estimates of Additional Costs of Selected Carbon Capture Technology

(percent increase in electric generating costs on levelized basis)

	New Construction	Retrofit[a]
Post-combustion	60%-70%	220%-250%
Pre-combustion	22%-25%	not applicable
Oxy-fuel	46%	170%-206%

Source: Massachusetts Institute of Technology, *The Future of Coal: An Interdisciplinary MIT Study* (2007), pp. 27, 30, 36, 149.

a. Assumes capital costs have been fully amortized.

In most carbon sequestration systems, the cost of capturing CO_2 is the largest component, possibly accounting for as much as 80% of the total.[60] In a 2008 study by McKinsey & Company, capture costs accounted for the majority of CCS costs estimated for demonstration plants and early commercial plants.[61] **Table 4** shows the McKinsey & Company estimates for three different stages of CCS development for new, coal-fired power plants.

Table 4. Estimates of CCS Costs at Different Stages of Development

(dollars per metric ton of CO_2, for new coal-fired powerplants)

	Capture	Transport	Storage	Total
Initial demonstration	$73-$94	$7-$22	$6-$17	$86-$133
Early commercial	$36-$46	$6-$9	$6-$17	$48-$73
Past early commercial[a]	—	—	—	$44-$65

Source: McKinsey & Company, *Carbon Capture and Storage: Assessing the Economics*, Sept. 22, 2008.

Notes: Source provided cost estimates in Euros. Euros converted to dollars at 1 Euro = $1.45, rounded to nearest dollar.

a. Cost ranges for capture, transport, and storage components for past early commercial-stage plants are not available from this study.

The MIT and McKinsey & Company studies both suggest that retrofitting power plants would lead to more expensive CCS costs, in general, compared to new plants on a levelized basis. Four reasons for higher costs include (1) the added expense of adapting the existing plant configuration for the capture unit; (2) a shorter lifespan for the capture unit compared to new plants; (3) a higher efficiency penalty compared to new plants that incorporate CO_2 capture from the design stage; and (4) the generating time lost when an existing plant is taken off-line for the retrofit.[62] Retrofitted plants could be less expensive if capture technology is installed on new plants that were designed "capture-ready," or if an older plant was already due for extensive revamping.[63]

[60] Furnival, "Burying Climate Change for Good."

[61] McKinsey & Company, *Carbon Capture and Storage: Assessing the Economics*, Sept. 22, 2008, at http://www.mckinsey.com/clientservice/ccsi/pdf/CCS_Assessing_the_Economics.pdf.

[62] McKinsey & Company, p. 29.

[63] McKinsey & Company, p. 30.

As these cost estimates indicate, capturing CO_2 at electricity-generating power plants would likely require more energy, per unit of power output, than is required by plants without CCS, reducing the plant efficiency. The additional energy required also means that more CO_2 would be produced, per unit of power output. (See **Appendix**.) Improving the efficiency of the CO_2 capture phase would likely produce the largest cost savings and reduce CO_2 emissions. Costs for each CCS project would probably not be uniform, however, even for those employing the same type of capture technology. Other site-specific factors, such as types and costs of fuels used by power plants, distance of transport to a storage site, and the type of CO_2 storage, would likely vary from project to project.

The DOE Carbon Capture and Sequestration Program

The DOE CCS program has had three main elements: (1) core research and development, consisting of laboratory and pilot-scale research for developing new technologies and systems for greenhouse gas mitigation; (2) demonstration and deployment, consisting of demonstration projects to test the viability of large-scale CCS technologies using regional partnerships; and (3) support for the DOE FutureGen project.[64]

According to DOE, the overall goal of the CCS program is to develop, by 2012, systems that will achieve 90% capture of CO_2 at less than a 10% increase in the cost of energy services and retain 99% storage permanence.[65] The research aspect of the DOE program includes a combination of cost-shared projects, industry-led development projects, research grants, and research at the National Energy Technology Laboratory. The program investigates five focus areas: (1) CO_2 capture; (2) carbon storage; (3) monitoring, mitigation, and verification; (4) work on non-CO_2 greenhouse gases; and (5) advancing breakthrough technologies.

After the 2007 DOE roadmap and program plan was made available, Congress passed the Energy Independence and Security Act of 2007 (P.L. 110-140), which authorized an expansion of the DOE carbon sequestration research and development program and increased its emphasis on large-scale underground injection and storage experiments in geologic reservoirs. The American Recovery and Reinvestment Act of 2009 (ARRA, P.L. 111-5) provided up to \$3.4 billion for CCS-related activities at DOE through FY2010, which will likely alter DOE's CCS program priorities over that time frame. On May 15, 2009, Energy Secretary Chu announced that Notices of Intent to issue \$2.4 billion of ARRA funding would be posted: \$1.52 billion for industrial carbon capture and storage, \$800 million for the Clean Coal Power Initiative, and \$80 million for geologic site characterization, training, research, and program administration.[66] The remaining \$1 billion provided in ARRA will be used to support the revival of FutureGen (see below).

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[64] DOE Carbon Sequestration Technology Roadmap and Program Plan 2007, p. 8. See http://www.netl.doe.gov/technologies/carbon_seq/refshelf/project%20portfolio/2007/2007Roadmap.pdf.

[65] Ibid., p. 5.

[66] For a summary of Secretary Chu's remarks, see http://www.energy.gov/news2009/7405.htm. For the funding opportunity announcements, see http://www.fossil.energy.gov/aboutus/budget/stimulus.html.

DOE CCS Research and Development Funding

The federal government has recognized the potential need for CCS technology—as part of broader efforts to address greenhouse-gas induced climate change—since at least 1997, when DOE spent approximately $1 million for the entire CCS program.[67] **Table 5** shows that DOE programs that provide funding for CCS-related activities total nearly $600 million for FY2009, a significant increase since 1997.[68] Funding for CCS R&D increased by nearly 58% from FY2008 to FY2009, excluding funding from ARRA.

Table 5. Funding for CCS-Related Activities at DOE

($ thousands)

	FY2008	FY2009	FY2010	ARRA
Clean Coal Power Initiative (CCPI)[a]	67,444	288,174	0	800,000
FutureGen[b]	72,262	0	0	1,000,000
Innovation for Existing Plants (IEP)[c]	35,083	50,000	41,000	—
Advanced Integrated Gasification Combined Cycle[d]	52,029	65,236	55,000	—
Advanced Turbines[e]	23,125	28,000	31,000	—
Industrial Carbon Capture Projects	—	—	—	1,520,000
Site Characterization, Training, Program Direction	—	—	—	80,000
Subtotal	252,943	431,410	127,000	3,400,000
Carbon Sequestration Greenhouse Gas Control[f]	105,985	136,000	130,865	—
Carbon Sequestration Energy Innovation Hub[g]	0	0	35,000	—
Carbon Sequestration Focus Area for Carbon Sequestration Science[h]	9,635	14,000	14,000	—
Subtotal for Carbon Sequestration	115,620	150,000	179,865	—
Total	368,563	581,410	306,865	3,400,000

Source: CRS, from the U.S. Department of Energy, FY2010 *Congressional Budget Request*, Volume 7, Fossil Energy Research and Development, at http://www.cfo.doe.gov/budget/10budget/Content/Volumes/Volume7.pdf; and U.S. Congress, House Committee on Appropriations, Conference Report to Accompany H.R. 1, 111th Cong., 1st sess., February 11, 2009, 111-16 (Washington: GPO, 2009).

Notes: FY2010 represents the requested amounts; FY2008 and FY2009 are amounts reported in the DOE FY2010 Congressional Budget Request. Overall Fossil Energy Research appropriations are included in CRS Report RL34417, *Energy and Water Development: FY2009 Appropriations*.

a. The FY2010 budget request does not include any funds for CCPI demonstration projects because $800 million is already provided by ARRA (P.L. 111-5) for Phase III of the CCPI program.

b. Language in ARRA indicated that $1 billion would be allocated for Fossil Energy R&D. On June 12, 2009, Secretary Chu announced that the funds would be used to support FutureGen.

[67] Personal communication, Timothy E. Fout, General Engineer, DOE National Energy Technology Laboratory, Morgantown, WV (July 16, 2008).

[68] Funding for FY2009 is according to U.S. Department of Energy, *FY2010 Congressional Budget Request*, Volume 7, Fossil Energy Research and Development, at http://www.cfo.doe.gov/budget/10budget/Content/Volumes/Volume7.pdf.

c. In its FY2010 budget request, DOE indicates that all the IEP activity in FY2010 is focused on the development of post-combustion CO_2 capture technology for new and existing plants. In FY2009, $33 million was focused on carbon capture. However, of the $50 million in total funding for IEP in FY2009, $12 million was allocated to developing and testing advanced water conservation technologies applicable to new and existing thermoelectric plants, and $5 million for mercury control research. No funding is requested for either activity in FY2010.

d. According to DOE, the IGCC activity is focused on developing advanced gasification-based technologies to reduce the costs of near-zero emissions (including CO_2) coal-based IGCC plants. The program is also intended to improve the thermal efficiency of the plants, and to achieve near-zero atmospheric emissions for all pollutants, including CO_2, SO_2, NOx, and mercury.

e. The Advanced Turbines program is focused on creating the technology base for turbines that will permit the design of near-zero atmospheric emission IGCC plants (including CO_2). Specifically, the program will focus in FY2010 on enabling hydrogen-fueled turbines in integrated gasification combined cycle systems that capture CO_2.

f. Carbon Sequestration includes research and development on all aspects of CCS, but most of the funding is allocated to the seven Regional Partnerships for large scale CO_2 capture, transportation, injection, and storage projects.

g. The Energy Innovation Hub is requested for the Carbon Sequestration program in FY2010, and would focus on enabling fundamental advances and discovery of novel and revolutionary capture/separation approaches to reduce the energy penalty and costs associated with CO_2 capture, according to DOE.

h. The Focus Area for Carbon Sequestration Science is part of the Carbon Sequestration program and will continue applied research in support of CO_2 injection and storage field efforts conducted by the seven Regional Partnerships.

DOE indicates in its FY2010 budget request that programs listed in **Table 5** support the mission to "ensure the availability of near-zero atmospheric emissions" and that "carbon dioxide (CO_2) capture and geologic storage (CCS) is a promising option for addressing this challenge."[69] In addition to the Carbon Sequestration program itself, for which DOE requested almost $180 million in FY2010 (**Table 5**), DOE requested a total of $127 million for the Innovation for Existing Plant (IEP) program, the Advanced Integrated Gasification Combined Cycle program, and the Advanced Turbine program. The Carbon Sequestration program is focused on all aspects of CCS: capture technology, transportation, and especially the injection and safe storage of CO_2. The other programs support the broader goal "to significantly reduce coal power plant emissions (including CO_2) and substantially improve efficiency to reduce carbon emissions, leading to a viable near-zero atmospheric emissions coal energy system and supporting carbon capture and storage."[70]

As noted above, funding provided under ARRA will likely increase funding for CCS-related programs dramatically above levels in previous years, and exceed the cumulative spending on CCS by DOE since 1997.

Loan Guarantees and Tax Credits

Appropriations represent one mechanism for funding carbon capture technology R&D and deployment; others include loan guarantees and tax credits, both of which are available under current law.

[69] Ibid, p. 23.

[70] DOE FY2010 Congressional Budget Request, p. 40.

Loan Guarantees

Loan guarantee incentives that could be applied to CCS were authorized under Title XVII of the Energy Policy Act of 2005 (EPAct2005, P.L. 109-58, 42 U.S.C. §§16511-16514), and were given indefinite authorization under the Omnibus Appropriations Act, 2009 (P.L. 111-8). Title XVII of EPAct2005 authorizes the Secretary of Energy to make loan guarantees for projects that, among other purposes, avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases. The Omnibus Appropriations Act for FY2009 restates the loan guarantee authority and provides $6 billion in loan guarantees for coal-based power generation and industrial gasification activities at retrofitted and new facilities that incorporate CCS or other beneficial uses of carbon. The act provides an additional $2 billion in loan guarantees for advanced coal gasification.[71]

Tax Credits

Title XIII of EPAct2005 provided for tax credits that could be used for Integrated Gasification Combined Cycle (IGCC) projects and for projects that use other advanced coal-based generation technologies (ACBGT). For these types of projects, the aggregate credits available under EPAct2005 totaled up to $1.3 billion: $800 million for IGCC projects, and $500 million for ACBGT projects. Qualifying projects under Title XIII of EPAct2005 were not limited to technologies that employ carbon capture technologies, but the Secretary of the Treasury was directed to give high priority to projects that include greenhouse gas capture capability. An additional $350 million of tax credits were made available for coal gasification projects.

Sections 111 and 112 of P.L. 110-343, Division B, the Energy Improvement and Extension Act of 2008 (part of the Emergency Economic Stabilization Act of 2008), increased the aggregate tax credits available from $1.65 billion to $3.15 billion. Section 111 added an additional $1.25 billion to the existing tax credit authority for ACBGT projects. Section 112 added an additional $250 million to $350 million in existing authority for the coal gasification investment credit, for gasification projects that separate and sequester at least 75% of the project's total CO_2 emissions.

Section 115 of the act added a new tax credit for sequestering CO_2 and storing it underground. The section provides for a credit of $20 per metric ton of CO_2 captured at a qualified facility and disposed of in secure geological storage, and $10 per metric ton if the CO_2 is used as a tertiary injectant for the purposes of enhanced oil or natural gas recovery. To qualify for the tax credit, the facility must capture at least 500,000 metric tons of CO_2 per year. If CO_2 is used for enhanced oil or gas recovery, a tax credit would be available only for an initial injection; CO_2 subsequently recaptured, recycled, and re-injected would not be eligible for a tax credit.

Regional Carbon Sequestration Partnerships

Beginning in 2003, DOE created seven regional carbon sequestration partnerships to identify opportunities for carbon sequestration field tests in the United States and Canada.[72] The regional

[71] U.S. Congress, House Committee on Appropriations, *Omnibus Appropriations Act, 2009, Division C—Energy and Water Development and Related Agencies Appropriations Act, 2009*, committee print, 111th Cong., 1st sess., March 11, 2009, p. 672.

[72] The seven partnerships are Midwest Regional Carbon Sequestration Partnership; Midwest (Illinois Basin) Geologic Sequestration Consortium; Southeast Regional Carbon Sequestration Partnership; Southwest Regional Carbon (continued...)

partnerships program is being implemented in a three-phase overlapping approach: (1) characterization phase (from FY2003 to FY2005); (2) validation phase (from FY2005 to FY2009); and (3) deployment phase (from FY2008 to FY2017).[73]

The third phase, deployment, is intended to demonstrate large-volume, prolonged injection and CO_2 storage in a wide variety of geologic formations. According to DOE, this phase is to address the practical aspects of large-scale operations, with an aim toward producing the results necessary for commercial CCS activities to move forward. On November 17, 2008, DOE made the seventh, and last, award for the large-scale carbon sequestration projects under phase three.[74] DOE has now awarded funds totaling $457.6 million (an average of approximately $65 million per project) to conduct a variety of large-scale injection tests over several years. In addition to DOE funding, each partnership also contributes funds ranging from 21% to over 50% of the total project costs.[75]

FutureGen

On February 27, 2003, President Bush proposed a 10-year, $1 billion project to build a coal-fired power plant that integrates carbon sequestration and hydrogen production while producing 275 megawatts of electricity, enough to power about 150,000 average U.S. homes. As originally conceived, the plant would have been a coal-gasification facility and would have produced and sequestered between 1 and 2 $MtCO_2$ annually. On January 30, 2008, DOE announced that it was "restructuring" the FutureGen program away from a single, state-of-the-art "living laboratory" of integrated R&D technologies—a single plant—to instead pursue a new strategy of multiple commercial demonstration projects.[76] In the restructured program, DOE would support up to two or three demonstration projects of at least 300 megawatts and that would sequester at least 1 $MtCO_2$ per year.

In its budget justification for FY2009, DOE cited "new market realities" for its decision, namely rising material and labor costs for new power plants, and the need to demonstrate commercial viability of IGCC power plants with CCS.[77] The budget justification also noted that a number of states are making approval of new power plants contingent on provisions to control CO_2 emissions, further underscoring the need to demonstrate commercial viability of a new generation of coal-based power systems. For FY2009, DOE requested $156 million for the restructured program, and specified that the federal cost-share would only cover the CCS portions of the demonstration projects, not the entire power system.

Prior to DOE's announced restructuring of the program, the FutureGen Alliance—an industry consortium of 13 companies—announced on December 18, 2007, that it had selected Mattoon,

(...continued)

Sequestration Partnership; West Coast Regional Carbon Sequestration Partnership; Big Sky Regional Carbon Sequestration Partnership; and Plains CO_2 Reduction Partnership; see http://www.fossil.energy.gov/programs/sequestration/partnerships/index.html.

[73] DOE Carbon Sequestration Technology Roadmap and Program Plan 2007, p. 36.

[74] DOE awarded $66.9 million to the Big Sky Carbon Sequestration Partnership. See http://www.fossil.energy.gov/news/techlines/2008/08059-DOE_Makes_Sequestration_Award.html.

[75] For more information about specific sequestration projects, see the DOE Carbon Sequestration Regional Partnerships website, at http://www.fossil.energy.gov/programs/sequestration/partnerships/index.html.

[76] See http://www.fossil.energy.gov/news/techlines/2008/08003-DOE_Announces_Restructured_FutureG.html.

[77] DOE FY2009 Budget Request, p. 16.

IL, as the host site from a set of four finalists.[78] In its January 30, 2008 announcement, DOE stated that the four finalist locations may be eligible to host an IGCC plant with CCS under the new program.

In the debate leading up to enactment of ARRA, the Senate amendment to H.R. 1 (known as the Collins-Nelson amendment) contained language, under Fossil Energy Research and Development, that made $2 billion "available for one or more near[-]zero emissions powerplant(s)."[79] Some observers noted that the language may refer to a plant or plants similar to the original conception for FutureGen, although the Senate amendment did not mention either FutureGen or a specific location where the plant would be built. The language referring to zero-emissions power plant(s) was removed in conference and was not included in the conference report to accompany ARRA; instead, $1 billion would be allocated for fossil energy research and development programs.

On June 12, 2009, Secretary Chu announced that the $1 billion of funding from ARRA will be used to support FutureGen, and that the plant will be built in Mattoon, IL, the site selected by the FutureGen Alliance in 2007.[80] According to DOE, its total anticipated contribution to FutureGen will be $1.073 billion, and the FutureGen Alliance will contribute between $400 and $600 million to the project. Under the terms of a provisional agreement with the FutureGen Alliance, DOE has stated that it will issue a Record of Decision on the project by the middle of July 2009, after which DOE would pursue the following:

- rapid restart of preliminary design activities;
- completion of a site-specific preliminary design and updated cost estimate;
- expansion of the Alliance sponsorship group;
- development of a complete funding plan; and
- potential additional subsurface characterization.

Some reports indicate that the newly revived plans for FutureGen call for an initial carbon capture goal of 60% for the facility, with the ultimate goal of achieving a 90% capture rate, the target set in the project's original conception.[81] Some environmental groups have expressed views that the lower capture rate may put FutureGen in the same category as other CCS commercialization projects, calling into question the status of FutureGen as a "flagship facility to demonstrate carbon capture and storage at commercial scale."[82]

[78] The four were Mattoon, IL; Tuscola, IL; Heart of Brazos (near Jewett, TX); and Odessa, TX.

[79] See http://appropriations.senate.gov/News/2009_02_09_Substitute_Amendment_to_HR1_%7BCollins_Nelson_Amendment%7D.pdf?CFID=23617867&CFTOKEN=75628290.

[80] See DOE announcement at http://www.fossil.energy.gov/news/techlines/2009/09037-DOE_Announces_FutureGen_Agreement.html.

[81] Ben Geman, "Enviros fault scaled-back FutureGen carbon goal," *Greenwire*, June 16, 2009.

[82] See Secretary Chu's announcement on FutureGen at http://www.energy.gov/news2009/7454.htm.

Current Issues and Future Challenges

A primary goal of developing and deploying CCS is to allow large industrial facilities, such as fossil fuel power plants and cement plants, to operate while reducing their CO_2 emissions by 80%-90%. Such reductions would presumably reduce the likelihood of continued climate warming from greenhouse gases by slowing the rise in atmospheric concentrations of CO_2. To achieve the overarching goal of reducing the likelihood of continued climate warming would depend, in part, on how fast and how widely CCS could be deployed throughout the economy.

Congress has supported CCS R&D for more than 10 years, and DOE spending increased substantially in FY2007 and FY2008 compared to previous years. The American Recovery and Reinvestment Act of 2009 (P.L. 111-5) increases that trend markedly, adding an additional $3.4 billion in CCS-related federal obligations through FY2010. It is likely that the large increase in funding will accelerate technological development of CCS systems.

The timeline for developing systems to capture and sequester CO_2, however, differs from when CCS technologies may become available for large-scale deployment and are actually deployed. In testimony before the Senate Energy and Natural Resources Committee on April 16, 2007, Thomas D. Shope, then Acting Assistant DOE Secretary for Fossil Energy, stated that under current (2007) budget constraints and outlooks CCS technologies would be available and deployable in the 2020 to 2025 timeframe. However, Mr. Shope added that "we're not going to see common, everyday deployment [of those technologies] until approximately 2045."[83] With enactment of ARRA, the budget constraints now are likely very different compared to when Mr. Shope testified in 2007; nevertheless, Congress faces several challenges to the rapid and widespread deployment of CCS.

The dramatic increase in CCS R&D funding provided for in ARRA will likely invite scrutiny of the relative roles of research, development, and deployment (technology-push mechanisms) versus the requirement for a successful technology to be fully commercialized. To achieve commercialization, the technology must also meet a market demand—a demand created either through a price mechanism or a regulatory requirement (demand-pull mechanisms). Even if technologies for capturing large amounts of CO_2 become more efficient and cheaper, few companies are likely to install such technologies until they are required to do so. H.R. 2454, for example, contains components of both demand-pull and technology-push, via the cap-and-trade provisions (demand-pull) and the distribution of emission allowances and other funding to promote CCS commercialization (technology-push). How the demand-pull and technology-push provisions in legislation such as H.R. 2454 would affect the rate of CCS commercialization and its deployment is unclear.

Major increases in capture technology efficiency will likely produce the greatest relative cost savings for CCS systems, but challenges also face the transportation and storage components of CCS. Ideally, storage reservoirs for CO_2 would be located close to sources, obviating the need to build a large pipeline infrastructure to deliver captured CO_2 for underground sequestration. If CCS moves to widespread implementation, however, some areas of the country may not have adequate reservoir capacity nearby, and may need to construct pipelines from sources to reservoirs. Identifying and validating sequestration sites would need to account for CO_2 pipeline

[83] Testimony of Thomas D. Shope, Acting Assistant Secretary for Fossil Energy, DOE, before the Senate Energy and Natural Resources Committee, Apr. 16, 2007; at http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_senate_hearings&docid=f:36492.pdf.

costs, for example, if the economics of the sites are to be fully understood. If this is the case, there would be questions to be resolved regarding pipeline network requirements, economic regulation, utility cost recovery, regulatory classification of CO_2 itself, and pipeline safety. In addition, Congress may be called upon to address federal jurisdictional authority over CO_2 pipelines under existing law, and whether additional legislation may be necessary if a CO_2 pipeline network grows and crosses state lines.

Although DOE has identified substantial potential storage capacity for CO_2, particularly in deep saline formations, large-scale injection experiments are only beginning in the United States to test how different types of reservoirs perform during CO_2 injection. Data from the upcoming experiments will undoubtedly be crucial to future permitting and site approval regulations; however, no existing federal regulations govern the injection and storage of CO_2 for the purposes of carbon sequestration. In July 2008, the U.S. Environmental Protection Agency (EPA) released a draft rule that would regulate CO_2 injection for the purposes of geological sequestration under the authority of the Safe Drinking Water Act, Underground Injection Control (UIC) program.[84] Some observers have noted that regulating CO_2 injection solely to protect groundwater, which is the focus of the UIC rulemaking process, may not fully address the primary purpose of storing CO_2 underground, which is to reduce atmospheric concentrations.[85] Cap-and-trade legislation introduced in the 111th Congress (H.R. 2454) contains provisions that would amend the Clean Air Act to broaden the regulatory scope and protect human health and the environment by minimizing the risk of CO_2 escape to the atmosphere.

In addition, liability, ownership, and long-term stewardship for CO_2 sequestered underground are issues that would need to be resolved before CCS is deployed commercially. Some states are moving ahead with state-level geological sequestration regulations for CO_2, so federal efforts to resolve these issues at a national level would likely involve negotiations with the states. In addition, acceptance by the general public of large-scale deployment of CCS may be a significant challenge if the majority of CCS projects involve private land.[86] Some of the large-scale injection tests could garner information about public acceptance, as local communities become familiar with the concept, process, and results of CO_2 injection tests. Apart from the question of how the public would accept the likely higher cost for electricity generated from plants with CCS, how a growing CCS infrastructure of pipelines, injection wells, underground reservoirs, and other facilities would be accepted by the public is as yet unknown.

[84] 73 *Federal Register*, 43491-43541 (July 25, 2008).

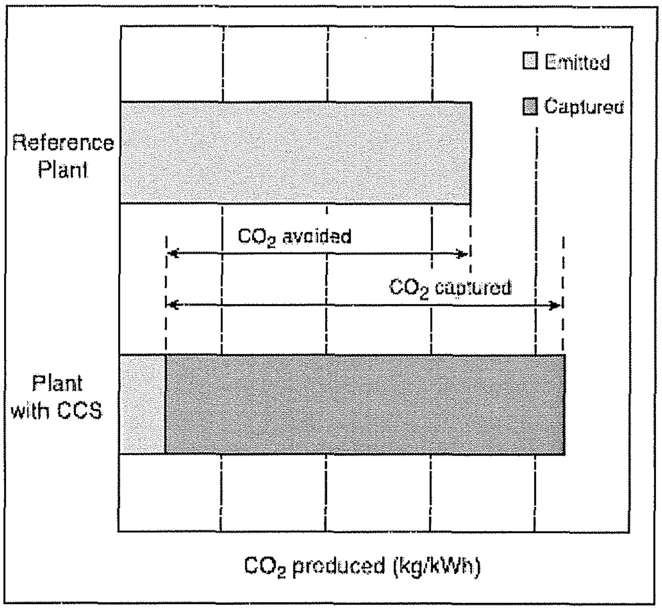
[85] See, for example, *Carbon Capture and Sequestration: Framing the Issues for Regulation*, an Interim Report from the CCSReg Project (December 2008), pp. 73-90; at http://www.ccsreg.org/interimreport/feedback.php.

[86] For more information on public acceptance of CCS, see CRS Report RL34601, *Community Acceptance of Carbon Capture and Sequestration Infrastructure: Siting Challenges*, by Paul W. Parfomak.

Appendix. Avoided CO_2

Figure A-1 compares captured CO_2 and avoided CO_2 emissions. Additional energy required for capture, transport, and storage of CO_2 results in additional CO_2 production from a plant with CCS. The lower bar in **Figure A-1** shows the larger amount of CO_2 produced per unit of power (kWh) relative to the reference plant (upper bar) without CCS. Unless no additional energy is required to capture, transport, and store CO_2, the amount of CO_2 avoided is always less than the amount of CO_2 captured. Thus the cost per tCO_2 avoided is always more than the cost per tCO_2 captured.[87]

Figure A-1. Avoided Versus Captured CO_2



Source: IPCC Special Report, Figure 8.2.

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[87] IPCC Special Report, pp. 346-347.

Pathways to a Low-Carbon Economy

Version 2 of the Global Greenhouse Gas Abatement Cost Curve

McKinsey&Company

Preface

Leaders in many nations are discussing ambitious targets for reducing emissions of greenhouse gases (GHGs). Some regions have already set reduction targets. The EU, for example, has set a target that 2020 emission levels should be 20% lower than those of 1990, and has stated its intention of aiming for a 30% reduction if other countries with high emissions also commit to comparable emission cuts. At the same time, an intense debate is underway regarding the technical and economic feasibility of different target levels, which emission reduction opportunities should be pursued, and the costs of different options for meeting the targets.

To provide a quantitative basis for such discussions, McKinsey & Company, supported by ten leading companies and organizations across the world, has developed a global greenhouse gas abatement data base. The abatement data base is comprised of an in-depth evaluation of the potential, and the costs, of more than 200 greenhouse gas abatement opportunities across 10 sectors and 21 world regions, and in a 2030 time perspective. This study builds on the earlier version of the global GHG abatement data base, conducted by McKinsey together with the Swedish utility Vattenfall, and published in January 2007. The current report incorporates updated assessments of the development of low-carbon technologies, updated macro-economic assessments, a significantly more detailed understanding of abatement potential in different regions and industries, an assessment of investment and financing needs in addition to cost estimates, and the incorporation of implementation scenarios for a more dynamic understanding of how abatement reductions could unfold. The financial crisis at the time of writing has not been taken into account in our analysis, based on the assumption that it will not have a major effect on a 2030 time horizon. This version of the report also reflects a deeper understanding by McKinsey into greenhouse gas abatement economics, gained through conducting 10 national greenhouse gas abatement studies during the last two years.

This study intentionally avoids any assessment of policies and regulatory choices. Instead, its purpose is to provide an objective and uniform set of data that can serve as a starting point for corporate leaders, academics, and policy makers when discussing how best to achieve emission reductions.

We would like to gratefully thank our sponsor organizations for supporting us with their expertise as well as financially: the Carbon Trust, ClimateWorks, Enel, Entergy, Holcim, Honeywell, Shell, Vattenfall, Volvo, and the World Wide Fund for Nature. We would also like to thank the members of our Academic Review Panel for their invaluable advice on the methodology and content of this study. Individual members of the panel might not necessarily endorse all aspects of the report: Dr. Fatih Birol (IEA, France), Prof. Mikiko Kainuma (NIES, Japan), Dr. Jiang Kejun (ERI, China), Dr. Ritu Mathur (TERI, India), Dr. Bert Metz (IPCC, Netherlands), Prof. Stephen Pacala (Princeton University, USA), Prof. Jayant Sathaye (LBNL, USA), and Prof. Lord Nicholas Stern (LSE, UK). Furthermore we thank the International Energy Agency for giving us access to their greenhouse gas emissions baseline. Finally we would like to thank our many colleagues within McKinsey who have helped us with advice and support.

Tomas Nauclér
Director

Per-Anders Enkvist
Principal

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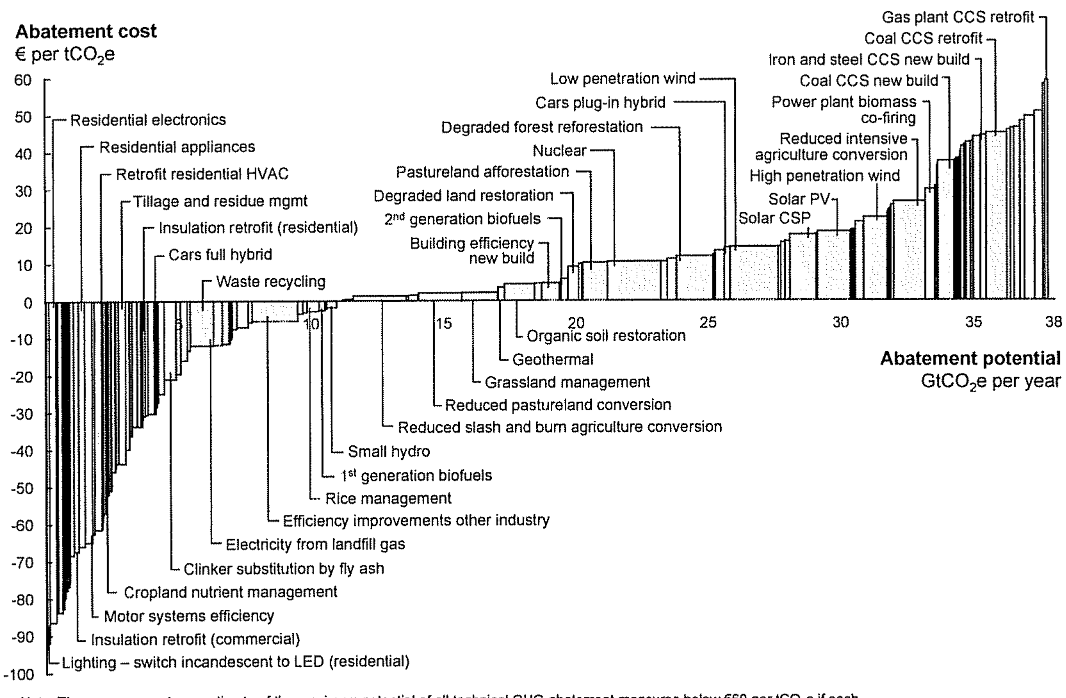
Summary of findings

Leaders in many nations are discussing ambitious targets for reducing emissions of greenhouse gases (GHGs) in order to mitigate the worst impact of climate change on the environment, human societies, and our economies. Many scientists and policy makers, including those in the European Union, believe that holding the rise in global mean temperatures below 2 degrees Celsius compared with pre-industrial times is an important aim, as they see this as a threshold when the implications of global warming become very serious.

McKinsey & Company's greenhouse gas abatement cost curve provides a quantitative basis for discussions about what actions would be most effective in delivering emissions reductions, and what they might cost. It provides a global mapping of opportunities to reduce the emissions of GHGs across regions and sectors (Exhibit 1).

Exhibit 1

Global GHG abatement cost curve beyond business-as-usual – 2030



Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €60 per tCO_2e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play.
Source: Global GHG Abatement Cost Curve v2 0

Our analysis finds that there is *potential* by 2030 to reduce GHG emissions by 35 percent compared with 1990 levels, or by 70 percent compared with the levels we would see in 2030 if the world collectively made little attempt to curb current and future emissions. This would be sufficient to have a good chance of holding global warming below the 2 degrees Celsius threshold, according to the Intergovernmental Panel on Climate Change (IPCC).[1]

Capturing enough of this potential to stay below the 2 degrees Celsius threshold will be highly challenging, however. Our research finds not only that all regions and sectors would have to capture close to the full potential for abatement that is available to them; even deep emission cuts in some sectors will not be sufficient. Action also needs to be timely. A 10-year delay in taking abatement action would make it virtually impossible to keep global warming below 2 degrees Celsius.

What would such an effort cost? We find that, if the most economically rational abatement opportunities are pursued to their full potential – clearly an optimistic assumption – the total worldwide cost could be €200 to 350 billion annually by 2030. This is less than 1 percent of forecasted global GDP in 2030, although the actual effect on GDP of such abatement efforts is a more complex matter that depends, among other things, on the financing of such abatement efforts. Turning to financing, the total upfront investment in abatement measures needed would be €530 billion in 2020 per year or €810 billion per year in 2030 – incremental to business-as-usual (BAU) investments. This corresponds to 5 to 6 percent of BAU investments in fixed assets in each respective year. As such, the investment required seems to be within the long-term capacity of global financial markets (as long as the current credit squeeze doesn't have significant consequences in this time horizon). Indeed, many of the opportunities would see future energy savings largely compensate for upfront investments.

1 The primary source of the climate science in this report is *Climate Change 2007, Fourth IPCC Assessment Report*. Intergovernmental Panel on Climate Change. We are also grateful to scientists Michel den Elzen, Detlef van Vuuren. and Malte Meinshausen for their contributions.

Potential exists to contain global warming below 2 degrees Celsius

This study focuses on technical abatement opportunities costing less than €60 per tonne of CO_2 equivalent (tCO_2e), and these are the opportunities shown on our "GHG abatement cost curve" (see "How to read the Greenhouse Gas abatement cost curve").[2] We have defined technical abatement opportunities as not having a material effect on the lifestyle of consumers and our results are therefore consistent with continuing increases in global prosperity. We have made high-level estimates of the size of more expensive technical opportunities, as well as changes in the behavior of consumers, which could potentially offer further potential for abatement. However, because these prospects are subject to a high degree of uncertainty, we have made no attempt to quantify their cost.

How to read the Greenhouse Gas abatement cost curve

McKinsey's global greenhouse gas abatement "cost curve" summarizes the technical opportunities (i.e., without a material impact on the lifestyle of consumers) to reduce emissions of greenhouse gases at a cost of up to €60 per tCO_2e of avoided emissions. The cost curve shows the range of emission reduction actions that are possible with technologies that either are available today or offer a high degree of certainty about their potential in a 2030 time horizon.

The width of each bar represents the potential of that opportunity to reduce GHG emissions in a specific year compared to the business-as-usual development (BAU). The potential of each opportunity assumes aggressive global action starting in 2010 to capture that specific opportunity, and so does not represent a forecast of how each opportunity will develop. The height of each bar represents the average cost of avoiding 1 tonne of CO_2e by 2030 through that opportunity. The cost is a weighted average across sub-opportunities, regions, and years. All costs are in 2005 real Euros. The graph is ordered left to right from the lowest-cost abatement opportunities to the highest-cost. The uncertainty can be significant for individual opportunities for both volume and cost estimates, in particular for the Forestry and Agriculture sectors, and for emerging technologies.

The priority in our research has been to look at the global emission reduction opportunities with one consistent methodology, rather than to deep dive in any individual emission reduction opportunity.

Therefore, the curve should be used for overall comparisons of the size and cost of different opportunities, the relative importance of different sectors and regions, and the overall size of the emission reduction opportunity, rather than for predictions of the development of individual technologies. It can also be used as a simulation tool, testing for different implementation scenarios, energy prices, interest rates and technological developments.

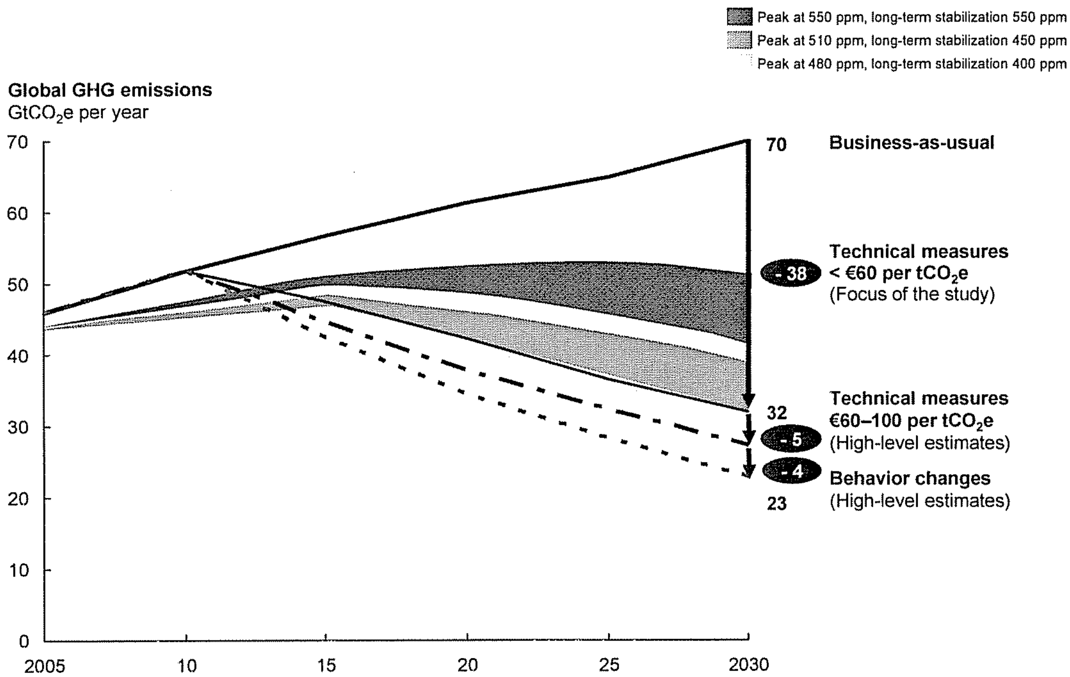
The reader should also bear in mind that the cost of abatement is calculated from a *societal perspective* (*i.e., excluding taxes*, subsidies, and with a capital cost similar to government bond rates). This methodology is useful because it allows for comparisons of opportunities and costs across countries, sectors and individual opportunities. However, it also means that the costs calculated are different from the costs a company or consumer would see, as these decision makers would include taxes, subsidies, and different interest rates in *their calculations. Therefore, the curve* cannot be used for determining switching economics between investments, nor for forecasting CO_2 prices. The cost of each opportunity also excludes transaction and program costs to implement the opportunity at a large scale, as these are highly dependent on how policy makers choose to implement each opportunity.

2 Using IPCC terminology, we studied the economic potential below €60 per tCO_2e of technical emission reduction opportunities. We chose an economic cut-off to enable us to compare the size of opportunities within different sectors and regions in an objective way. We chose €60 per tCO_2e as higher cost measures tend to be early stage technologies with development paths that are difficult to project.

The cost curve identifies a potential abatement of 38 $GtCO_2e$ (Exhibit 2) in 2030, relative to BAU emissions of 70 $GtCO_2e$. Our high-level estimates of additional potential from more expensive technical measures and changes in behavior, adds up to an additional 9 $GtCO_2e$. Theoretically, capturing the full abatement potential across sectors and regions starting in 2010, 2030 emissions would be between 35 and 40 percent lower than they were in 1990, the reference year for the Kyoto Protocol and many current discussions. Relative to the 2030 business-as-usual (BAU) emissions[3], emissions would decrease by 65 to 70 percent. These emission levels would be broadly consistent with an emissions pathway that would see the atmospheric concentration of GHGs peaking at 480 parts per million (ppm) and then start decreasing. According to the IPCC's analysis, such a pathway would result in a likely average increase of the global mean temperature of just below 2 degrees Celsius.

Exhibit 2

Emissions relative to different GHG concentration pathways



Note: As a reference, 1990 total emissions were 36 Gt CO_2e
Source: Global GHG Abatement Cost Curve v2 0; Houghton; IEA; IPCC; den Elzen; Meinshausen; OECD; US EPA; van Vuuren

Capturing the full abatement potential is a major challenge

It is one thing to have the *potential* to make deep cuts in GHG emissions; it is another for policy makers to agree on and implement effective emission reduction policies, and for companies, consumers and the public sector to take action to make this reduction a reality. Capturing all the opportunities would entail change on a huge scale. In Transport, for instance, the assumption in our study is that 42 million hybrid vehicles (including plug-ins) could be sold by 2030 – that's a full 40 percent of all new car sales.

3 To build a comprehensive BAU projection, we combined the projections of the International Energy Agency's (IEA) World Energy Outlook 2007 for CO_2 emissions from energy usage, Houghton's projections for CO_2 emissions from land use and land-use change, and the US Environmental Protection Agency's (EPA) projections for non-CO_2 GHGs. See chapter 2 for details.

In Forestry, the assumption is that we could until 2030 avoid the deforestation of 170 million hectares, equivalent to twice the land area of Venezuela, and plant new forests on 330 million hectares of currently marginal land – the equivalent of foresting much of India. In Power, the share of low-carbon generation technologies such as renewables, nuclear and carbon capture and storage have could rise to about 70 percent of global electricity production from 30 percent in 2005. After careful analysis, we believe such change would be feasible if there was concerted global action to go after each opportunity – this is the potential we aim to portray in our curve – but implementing all of the opportunities on our curve to their full extent clearly represents a massive change.

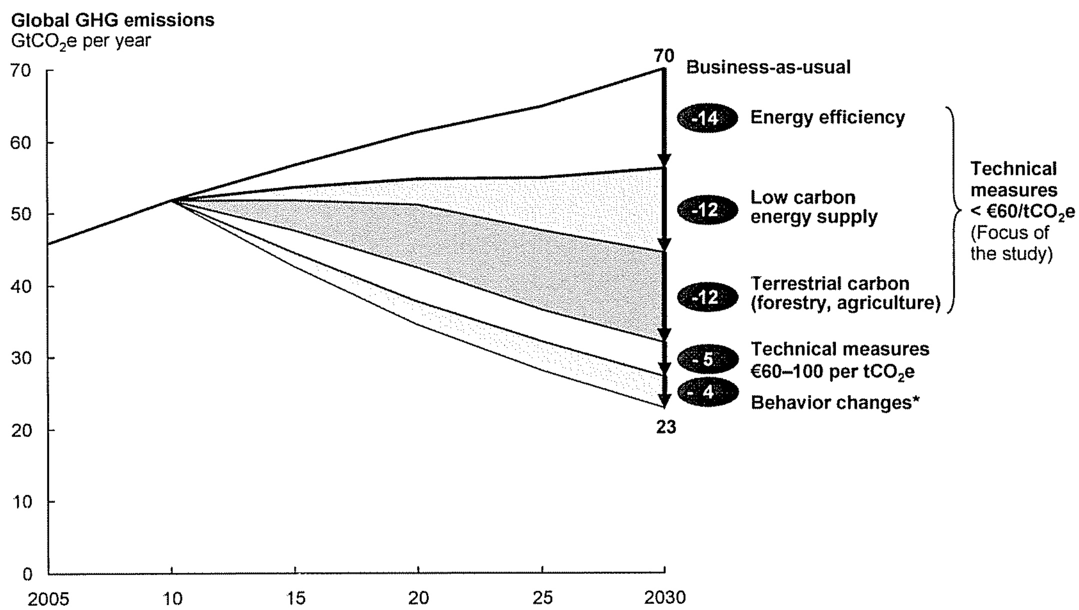
Another way to illustrate the challenge is to look at carbon productivity – the amount of GDP produced per unit of CO_2 emitted. In the period from 2005 to 2030, emissions would need to decrease by 35 to 50 percent to attain a pathway likely to achieve the 2 degrees Celsius threshold. As the world economy is set to more than double during the same time period, this implies almost quadrupling the global carbon productivity. This corresponds to increasing the annual global carbon productivity gains from 1.2 percent in the BAU, to 5 to 7 percent.

Four major categories of abatement opportunities

The abatement opportunities in the period between now and 2030 fall into four categories: energy efficiency, low-carbon energy supply, terrestrial carbon (forestry and agriculture), and behavioral change. The first three, technical abatement opportunities which are the focus of our study, add up to a total abatement opportunity of 38 $GtCO_2e$ per year in 2030 relative to annual BAU emissions of 70 $GtCO_2e$ (Exhibit 3)[4]:

Exhibit 3

Major categories of abatement opportunities



* The estimate of behavioral change abatement potential was made after implementation of all technical levers; the potential would be higher if modeled before implementation of the technical levers
Source: Global GHG Abatement Cost Curve v2 0; Houghton; IEA; US EPA

4 Key abatement data for 2020 can be found in the appendix.

- **Energy efficiency (opportunity of 14 GtCO_2e per year in 2030).** There are a large number of opportunities to improve the energy efficiency of vehicles, buildings, and industrial equipment, thereby reducing energy consumption. More fuel-efficient car engines, better insulation of buildings, and efficiency controls on manufacturing equipment are just a few of the possibilities. If all energy efficiency opportunities identified in our research were captured, annual growth in global electricity demand between 2005 and 2030 would be reduced from 2.7 percent per year in the BAU case to about 1.5 percent.
- **Low-carbon energy supply (opportunity of 12 GtCO_2e per year in 2030).** There are many opportunities to shift energy supply from fossil fuels to low-carbon alternatives. Key examples include electricity production from wind, nuclear, or hydro power, as well as equipping fossil fuel plants with carbon capture and storage (CCS), and replacing conventional transportation fuel with biofuels. If these low-carbon alternatives were to be fully implemented, we estimate that they have the potential to provide about 70 percent of global electricity supply by 2030 compared with just 30 percent in 2005; and that biofuels could provide as much as 25 percent of global transportation fuel by 2030. This would constitute a major shift in global energy supply. Several of these low-carbon energy technologies are too expensive today to deploy on a large scale without financial incentives, emphasizing the need to provide sufficient support to make them travel down the learning curve allowing them to contribute to their full potential.[5]
- **Terrestrial carbon – forestry and agriculture (opportunity of 12 GtCO_2e per year in 2030).** Forests and soils act as natural sinks for carbon. Halting ongoing tropical deforestation, reforesting marginal areas of land, and sequestering more CO_2 in soils through changing agricultural practices would increase carbon sequestration. This would lead to negative net emissions of CO_2e into the atmosphere from these sectors in the period we have studied (implying that more carbon is stored than is released from these sinks), a major abatement opportunity versus the BAU in which deforestation continues. However, capturing these opportunities would be highly challenging. More than 90 percent of them are located in the developing world, they are tightly linked to the overall social and economic situation in the concerned regions, and addressing the opportunities at this scale has not before been attempted. Our estimate of the feasibility and cost of this opportunity is therefore subject to significant uncertainty. We also note that terrestrial carbon opportunities are temporary in nature because the sinks would saturate between 2030 and 2050, so that, at the end of this period, there would be few additional areas of marginal land left available for re-forestation.

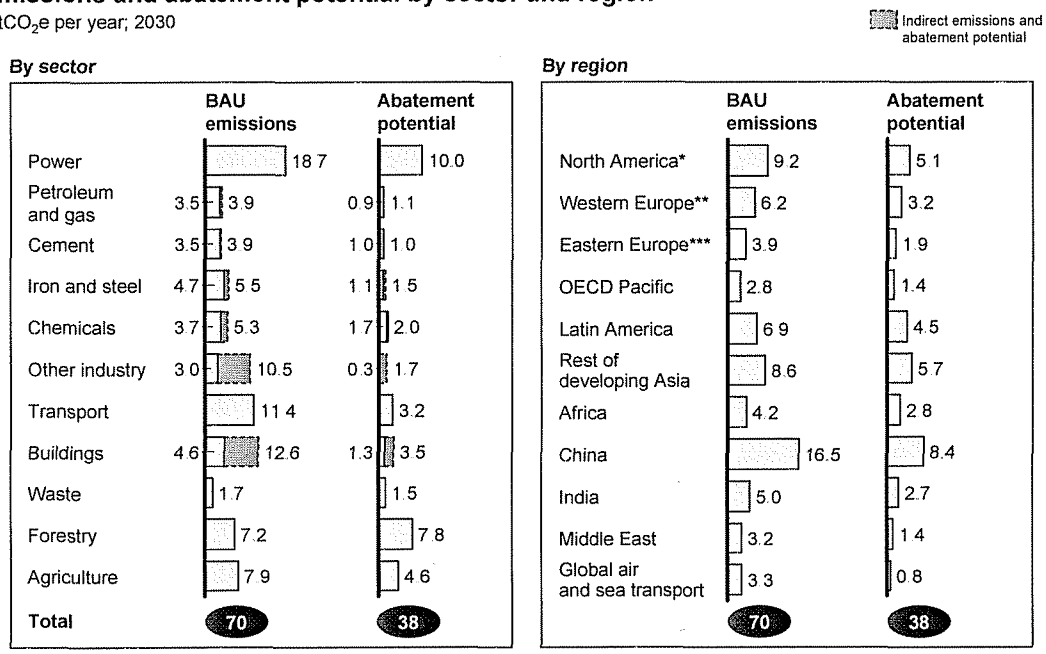
Abatement opportunities in these three categories are spread across many sectors of the economy. Approximately 29 percent of the total is in energy supply sectors (electricity, petroleum and gas), 16 percent in the industrial sector, 22 percent in sectors with significant consumer influence (transportation, buildings, waste), and the remaining 33 percent in land-use related sectors (forestry and agriculture). Some 30 percent of the total opportunity is located in the developed world and 70 percent in the developing world (Exhibit 4). A key driver for the high share of abatement potential in developing regions is the fact that a very large share of the opportunity in forestry and agriculture resides there. It should be noted that the relative share of abatement potential in different regions does not imply anything about who should pay for emissions reduction.

5 We have only included technologies in our curve that we see as technologically proven, that could credibly have costs lower than €60 per tCO_2e abated in 2030, and that we can envisage having a major abatement impact by 2030. There are also many technologies that did not pass our criteria to be included in the curve since they are too early in their development stage, but that could also have a major impact in the period after 2030.

Exhibit 4

Emissions and abatement potential by sector and region

$GtCO_2e$ per year; 2030



* United States and Canada
** Includes EU27, Andorra, Iceland, Lichtenstein, Monaco, Norway, San Marino, Switzerland
*** Russia and non-OECD Eastern Europe
Note: To obtain the total BAU emissions, only direct emissions are to be summed up. To obtain total abatement potential, indirect emission savings need to be included in the sum
Source: Global GHG Abatement Cost Curve v2 0; Houghton; IEA; UNFCCC; US EPA

We estimate that another 3.0–6.0 $GtCO_2e$ per year of technical abatement opportunities in these three categories are available at a cost of between €60 and €100 per tCO_2e. This range of higher cost abatement has not been the focus of our research, and the level of uncertainty in our estimates is much higher than for the lower cost opportunities. Examples of these more expensive abatement opportunities include retiring relatively young fossil fuel based power plants and replacing them with low-carbon options and in heavy industry, additional energy efficiency measures are possible if the cost threshold is increased.

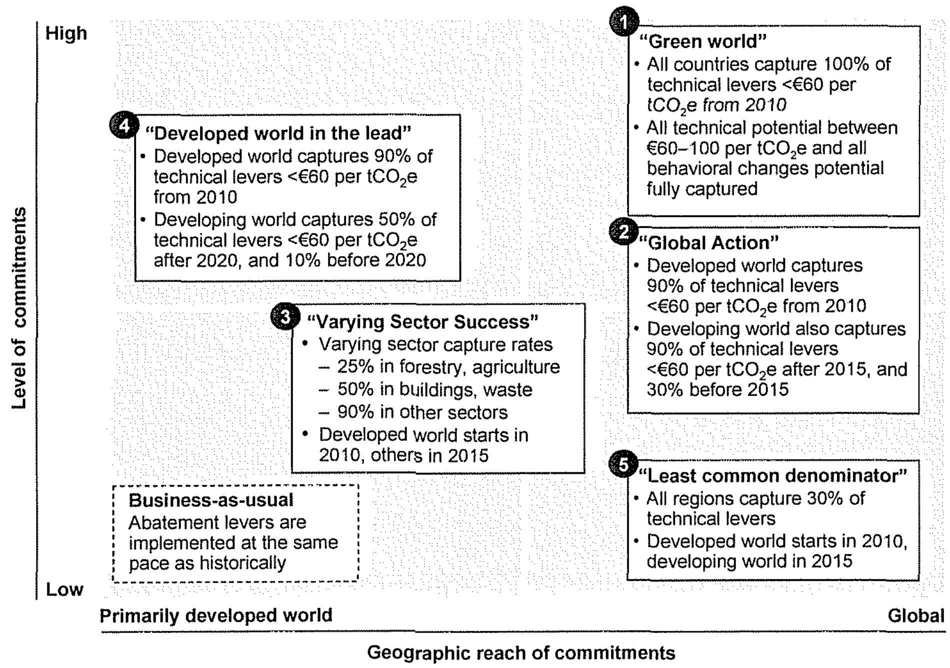
The fourth category of abatement opportunity is behavioral change. In an optimistic case – and there is a high degree of uncertainty in these estimates – this could yield between another 3.5–5.0 $GtCO_2e$ per year of abatement in 2030. Key opportunities include reducing business and private travel, shifting road transport to rail, accepting higher domestic temperature variations (reducing heating/cooling), reducing appliance use, and reducing meat consumption. Changing behavior is difficult and the abatement realized would depend heavily on whether, and to what extent, policy makers establish effective incentives.

All regions and sectors need to maximize their capture of the emissions potential

The fragmentation of the opportunity across sectors and regions demonstrates the importance of global cross-sector action to cut emissions, regardless of who pays for such efforts. The 38 $GtCO_2e$ of abatement on our 2030 cost curve is a maximum potential estimate that assumes the effective implementation of all abatement opportunities, starting promptly in 2010. In reality, there will likely be delays in policy action, and varying ambition levels and success rates of businesses and consumers when going after the opportunities. Our analysis of five different implementation scenarios finds that, if there are significant shortfalls in any major sector or region, measures in other sectors or regions – even at a higher cost – would only partly be able to compensate (see Chapter 6 of this report for detail on the five scenarios and Exhibit 5 for a summary).

Exhibit 5

Integrated implementation scenarios 2010–2030



Source: Global GHG Abatement Cost Curve v2 0

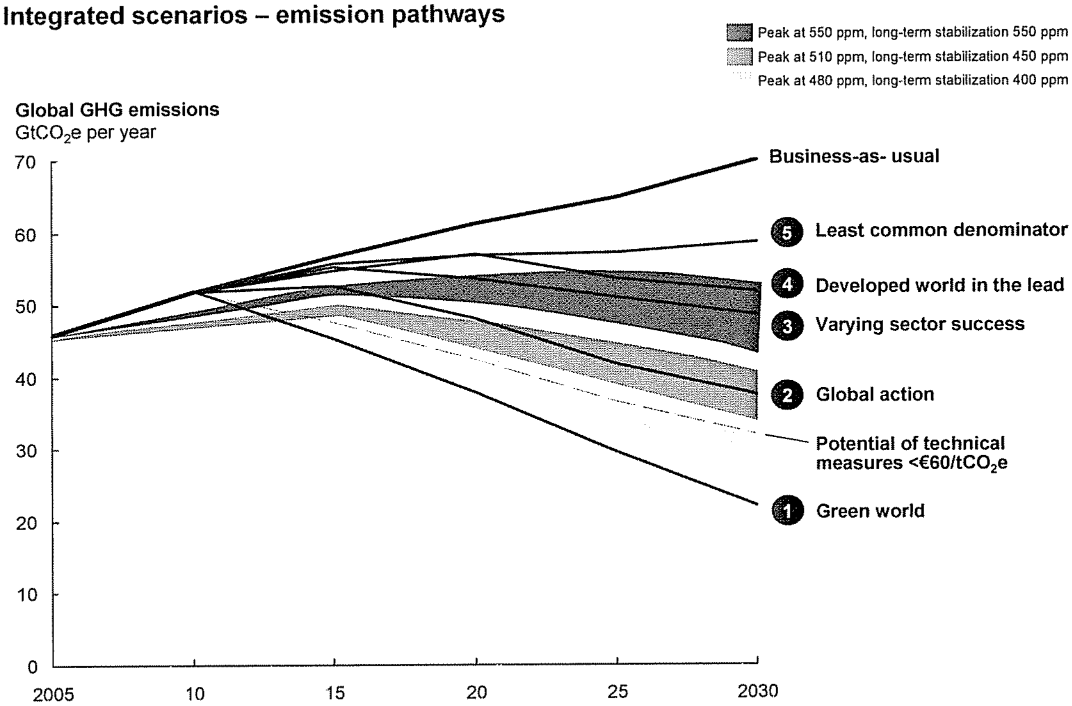
We find that only our "Green World" and "Global Action" scenarios, both of which assume an aggressive global commitment to abate GHGs across regions and sectors, would achieve pathways with a significant chance of containing global warming below 2 degrees Celsius (Exhibit 6). The three other scenarios would put the world on track to achieve a 550 ppm pathway or higher that would offer only a 15–30 percent likelihood of limiting global warming to below 2 degrees Celsius, according to the external estimates we have used.

Delaying action for 10 years would mean missing 2 degrees Celsius aim

If policy makers aim to stabilize global warming below 2 degrees Celsius, time is of the essence. Our model shows that if global abatement action were to start in 2020 instead of 2010, it would be challenging to achieve even a 550 ppm stabilization path, even if more expensive technical measures and behavioral changes were also implemented (Exhibit 7).

Exhibit 6

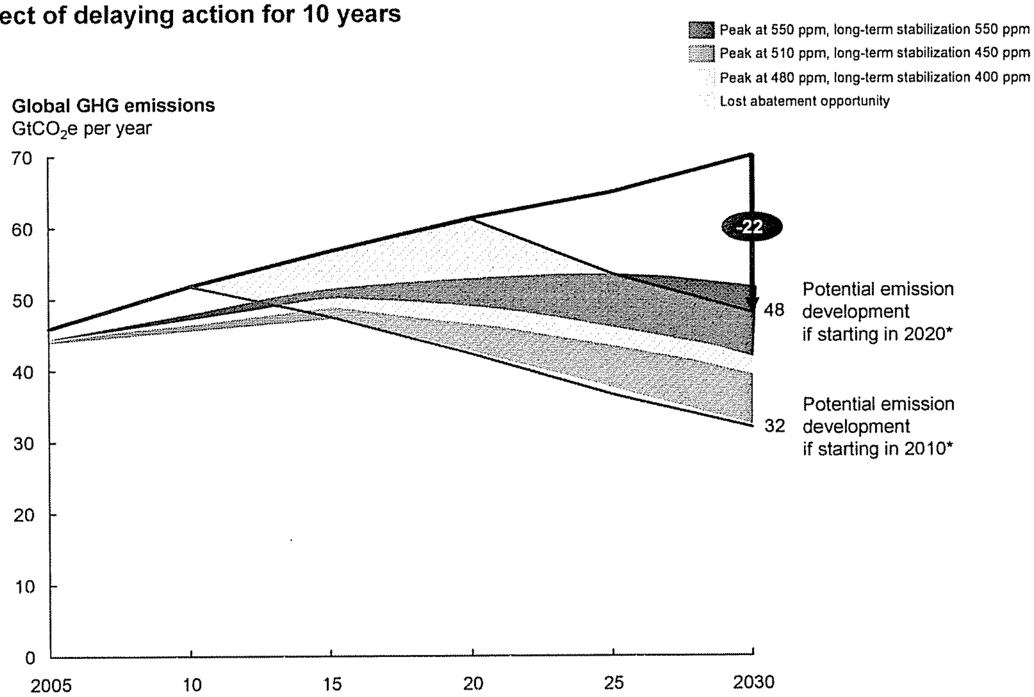
Integrated scenarios – emission pathways



Source: Global GHG Abatement Cost Curve v2 0; Houghton; IEA; IPCC; den Elzen; Meinshausen; OECD; US EPA; van Vuuren

Exhibit 7

Effect of delaying action for 10 years



* Technical levers <€60/tCO_2e

Source: Global GHG Abatement Cost Curve v2 0; Houghton; IEA; OECD; EPA; den Elzen; van Vuuren, Meinshausen

First, and most obvious, delay would mean that emissions would continue to grow according to the BAU development instead of declining. Second, building high-carbon infrastructure in sectors such as Buildings, Power, Industry, and Transport would lock in higher energy use for decades to come. In our model, the effective lifetime of carbon-intense infrastructure across sectors is, on average, 14 years. The result is that by delaying action for one year, an estimated 1.8 $GtCO_2e$ of abatement would be lost in that specific year[6]. Consequently, the world would be committed to cumulative emissions over the next 14 years of 25 $GtCO_2e$. In terms of atmospheric concentration, the continued BAU emissions growth coupled with the lock-in effect would lead to a 5 ppm higher expected peak CO_2e concentration.[7]

Future energy savings could largely pay for upfront investments

If the world were to successfully implement every measure on the cost curve, in strict order from low-cost to higher-cost in sequence – in other words be more economically rational than reality would normally suggest – the theoretical average cost of the abatement opportunities would be €4 per tCO_2e in 2030, and the total cost for realizing the whole curve would be some €150 billion. Transaction and program costs, that are not part of our curve[8], are often estimated at an average of between €1 and 5 per tCO_2e abated, making a total of approximately €40 to 200 billion for the 38 $GtCO_2e$ of abatement opportunities on our cost curve. This would make the total annual global cost approximately €200 to 350 billion by 2030. This estimate should be treated with significant caution for two reasons: One, the assumption that opportunities would effectively be addressed from left to right in our curve is a highly optimistic one. Two, there would in reality be significant dynamic effects in the economy from a program of this magnitude – effects that could work to either increase or decrease the cost depending on how they were implemented and that have not been taken into account in our analysis.

A large share of the abatement opportunities involves investing additional resources upfront to make existing or new infrastructure more carbon efficient – including all energy efficiency measures and much of the renewable energy measures – and then recouping part or all of that investment through lower energy or fuel spending in the future. There is about 11 $GtCO_2e$ per year of abatement potential in 2030 in which energy savings actually outweigh the upfront investment. In short, these measures would have a net economic benefit over their lifetime, even without any additional CO_2 incentive. If there are such substantial opportunities with net economic benefits over time, why haven't consumers and entrepreneurs already captured this potential? The reason is that a range of market imperfections, such as agency issues, act as a barrier and disincentive to making the necessary investments. As an example, builders have little incentive to add insulation beyond technical norms to new homes when it is the home-owner, not the builder, who will enjoy lower energy bills during the next decades.

6 Calculated as the difference in emissions caused by infrastructure built in the year 2010 in the BAU versus if all low-carbon options according to our curve were pursued.

7 The effect of a 10-year delay is that 2030 emissions end up in middle of the stabilization path that peaks at 550 ppm, instead of at the high end of the path that peaks at 480 ppm. Rounding the difference to 50 ppm (to account for the fact that emissions end up in the middle of the 550 ppm scenario and the high end of the 480 ppm scenario) makes the effect 5 ppm per year.

8 The reason for this is that such costs reflect political choices about which policies and programs to implement and vary from case to case. It is therefore not possible to incorporate these costs in the abatement curve in an objective way and maintain the ability to compare abatement potentials across regions and sectors.

Globally, financing looks manageable, but individual sectors will face big challenges

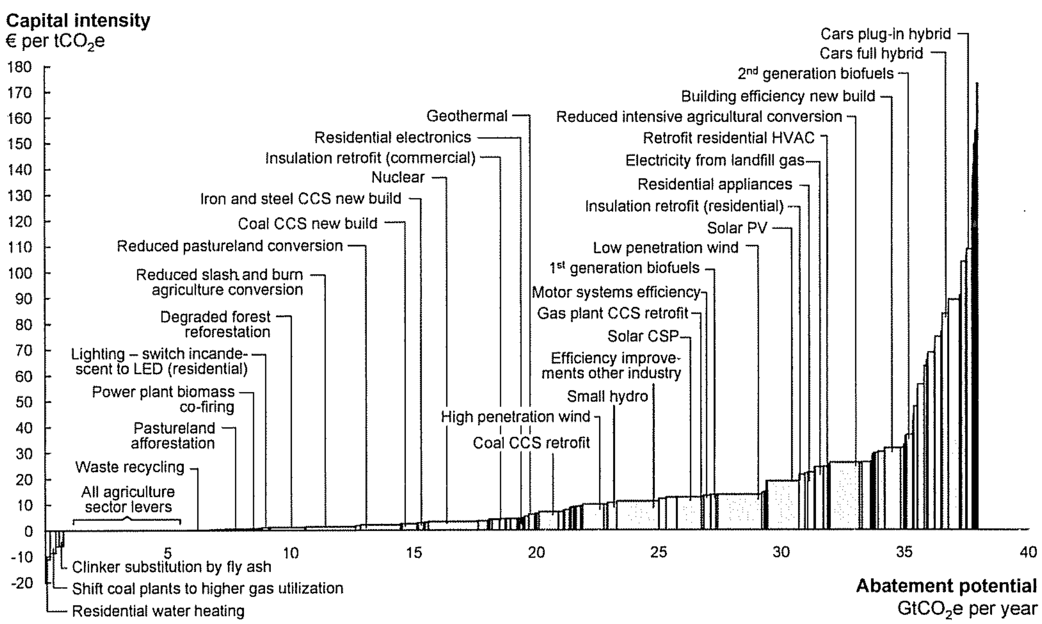
The total investment to achieve all the measures on our cost curve amounts to €530 billion per year in 2020 and €810 billion per year in 2030, on top of BAU investments that would happen anyway. This corresponds to 5 to 6 percent of the BAU investments in fixed assets in each respective year. While financing is a major test in the current credit squeeze, it seems unlikely to us that, at the global level, financing these additional investments would be a bottleneck to action on reducing emissions in a 2030 time horizon.

A more detailed view at the investments required highlights possible financing challenges at a sector and regional level. Indeed, over 60 percent of the investments required in addition to the BAU turn out to be needed in the Transport and Buildings sectors, and close to 60 percent of the total investments turn out to be needed in developing countries. Although the net additional cost of investing in fuel-efficient vehicles and energy-efficient houses is typically low, as much of the investment is regained through energy savings, finding effective ways to incentivize and finance the (sometimes considerable) additional upfront expenditure may not be easy.

When analyzing the capital intensity[9] of individual abatement opportunities, it becomes clear that the cheapest abatement opportunities are not always those with the lowest capital spend (Exhibit 8).

Exhibit 8

Capital intensity by abatement measure



Source: Global GHG Abatement Cost Curve v2 0

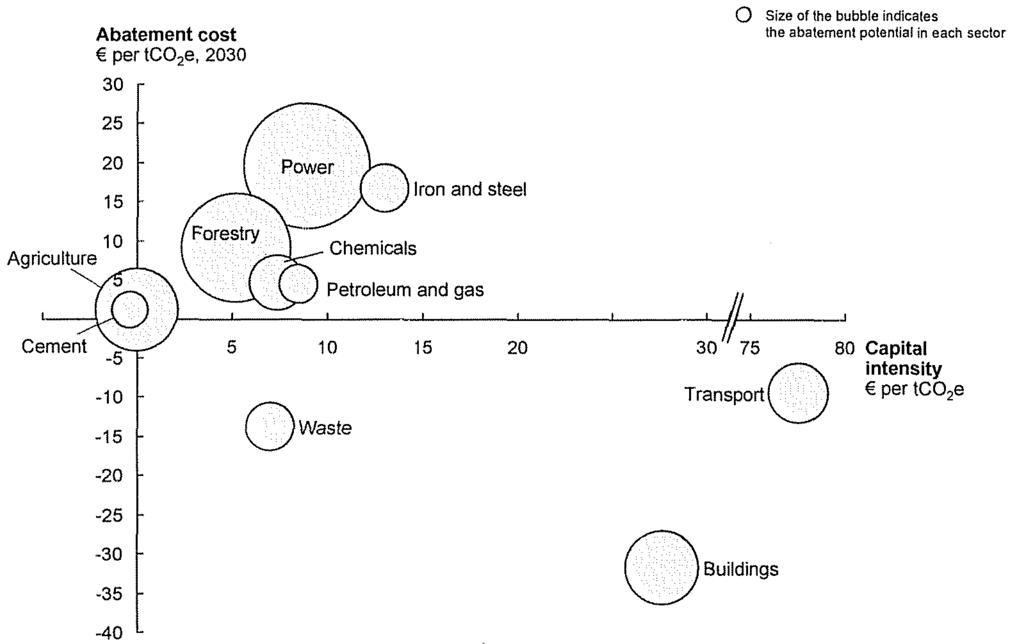
9 We define the capital intensity of an abatement measure as the additional upfront investment relative to the BAU technology, divided by the total amount of avoided emissions over the lifetime of the asset. For a more fuel efficient car, for instance, the capital intensity would be calculated as the additional upfront investment compared to the BAU technology, divided by the amount of CO_2 saved through lower fuel consumption during the lifetime of the car. The main difference with abatement cost is that the capital intensity calculation does not take financial savings through lower energy consumption into account.

For instance, many energy-efficiency opportunities that appear on the left-hand side of the cost curve end up much further to the right in the capital intensity curve. This demonstrates the different priorities that could emerge in a capital-constrained environment. Investors might choose to fund the opportunities with the lowest capital intensity rather than the ones with lowest cost over time. This would make the cost of abatement substantially higher over time.

Comparing the abatement cost and investments shows that the implementation challenges will be very different across sectors (Exhibit 9). In Transport and Buildings, upfront financing might be challenging but the cost is actually low once investments have been made. In several of the industrial sectors, average abatement costs are relatively high whereas upfront investments are lower. Making the abatement happen in these sectors is likely more a question about compensating companies for the high costs, than it is about financing the investments. Finally, in Forestry and Agriculture, both costs and investments are relatively low. Here, the implementation challenges are practical rather than economical, namely, designing effective policy and an effective way of measuring and monitoring the abatement.

Exhibit 9

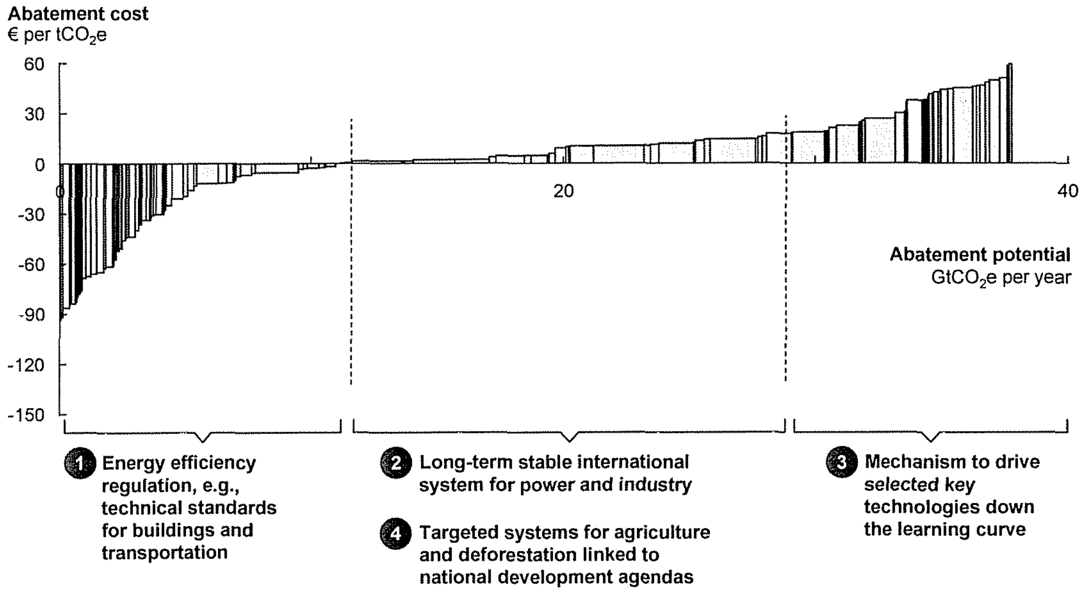
Capital intensity and abatement cost



Source: Global GHG Abatement Cost Curve v2 0

Exhibit 10

Key areas of regulation



Source: Global GHG Abatement Cost Curve v2 0

Four areas of regulation will be key to achieving low-cost emission reduction

Achieving the deep emission cuts deemed necessary by the IPCC to stabilize global temperatures presents a huge policy challenge. Although we do not take a view on what policies decision makers should implement, we highlight four policy areas that we believe will be important to reduce emissions at the lowest possible cost (Exhibit 10):

1. Implementing regulation to overcome the market imperfections that prevent the energy efficiency opportunities with net economic benefits from materializing, e.g., through technical norms and standards;
2. Establishing stable long-term incentives to encourage power producers and industrial companies to develop and deploy greenhouse gas efficient technologies, e.g., in the form of a CO_2 price or a CO_2 tax;
3. Providing sufficient incentives and support to improve the cost efficiency of promising emerging technologies; and
4. Ensuring that the potential in forestry and agriculture is effectively addressed, primarily in developing economies, linking any system to capture abatement closely to their overall development agenda.

* * *

This study does not take a view on current climate science, but rather focuses on providing an objective, globally consistent data set on opportunities to reduce GHG emissions and their likely cost and investments. We hope that this analysis will serve as a useful starting point for discussions among companies, policy makers, and academics on how best to manage the transition to a low-carbon economy.

1. Objectives and approach

During 2006, McKinsey and the Swedish utility Vattenfall collaborated to develop a global greenhouse gas (GHG) abatement cost curve. The project aspired to map the global opportunities to reduce emissions of GHGs and to quantify the impact on emissions, and the cost of each opportunity. The objective was to provide the first globally consistent dataset as a starting point for global discussions about how to reduce GHG emissions, showing the relative importance of different sectors, regions, and abatement measures, and providing a factual basis on the costs of reducing emissions.

As we continue to analyze opportunities for the abatement of emissions, we are gradually improving the resolution and depth of the map we are creating. We might characterize the first version of the Global Cost Curve as a 16th century map of the world of the economics of global climate change mitigation. Version 2 has, perhaps, brought us into the 18th century. This report significantly updates and complements the original GHG abatement cost curve in several respects:

1. This report significantly enhances the resolution of our sector, regional, and temporal analysis. We now model GHG abatement opportunities for 10 sectors, 21 regions, and five timeframes (five-year intervals from 2005 to 2030).[10]
2. We have updated the data set to reflect the best current view on the business-as-usual emissions development, the future trajectory of energy prices, and on the development of low-carbon technologies.
3. We have modeled investment levels and cash-flow implications in addition to abatement costs.
4. We have studied several different implementation scenarios and sensitivities to enable a more dynamic view on emission reduction pathways than provided in our first report on the cost curve.
5. We have also incorporated the insights McKinsey has gained over the last two years from conducting national GHG abatement projects for several of the world's largest economies.[11]

10 The 10 sectors are Power, Petroleum and Gas, Cement, Iron and Steel, Chemicals, Transport, Buildings, Forestry, Agriculture, and Waste. The 21 regions we cover are G8+5 countries plus "rest of regions": Brazil, Canada, China, France, Germany, India, Italy, Japan, Mexico, Russia, South Africa, United Kingdom, United States, Middle East, Rest of Latin America, Rest of EU27, Rest of OECD Europe, Rest of Eastern Europe, Rest of Africa, Rest of developing Asia, and Rest of OECD Pacific.

11 McKinsey has published a number of national GHG abatement studies, often in cooperation with or on behalf of other organizations, including analyses of the cost curve in Australia, Czech Republic, Germany, Sweden, Switzerland, the United Kingdom, and the United States. All of these are available at www.mckinsey.com/clientservice/ccsi. Several other national studies are ongoing.

Consistent with McKinsey's original cost-curve analysis, we apply a strictly economic lens to the issue of emission reductions. While we realize that the choice of which GHG emission reduction measures to implement involves many noneconomic considerations, we believe that economics is a useful starting point for discussions about how to reduce emissions. We have also opted to analyze the broadest possible scope of GHG emissions to cover all major sectors, world regions, and types of GHGs. We believe that such a comprehensive view is necessary to arrive at effective factual comparisons between options in different sectors and regions, and to compare global opportunities to reduce emissions with the emission pathways that the Intergovernmental Panel on Climate Change (IPCC) estimates to be necessary.

By opting for such a broad analytical scope, we necessarily limit the depth to which we can explore individual emission reduction opportunities. There are plenty of global investigations that go much deeper into individual opportunities such as wind power, biofuels, and passive houses. We hope the value of our work is that instead it takes a global, cross-sector view using a single consistent methodology, therefore allowing for effective comparisons of the size and cost of different opportunities.

As in our first report, we explicitly avoid drawing conclusions about which policy regimes would be most effective or fair; nor do we assess current climate science, drawing instead on the analysis of the IPCC and IPCC authors.

We should note that the cost curve embodies a large set of assumptions to estimate available opportunities to abate GHGs. While we believe that our figures are reasonable estimates given the information available, readers should be aware that by necessity when estimating 20 years into the future, many of these figures contain a considerable uncertainty.

We have developed our assessment of the opportunities available to reduce emissions in each sector in cooperation with our ten sponsor organizations, an extensive network of experts from industry and academia, and McKinsey's own expert network.

2. The challenge of rising GHG emissions

2.1 Why do GHG emissions matter?

According to the Intergovernmental Panel on Climate Change (IPCC) in its Fourth Assessment Report, "most of the observed increase in global average temperatures since the mid-20th century is very likely due to the observed increase in anthropogenic GHG concentrations"[12]. The IPCC continues laying out what average global temperature increase it expects if global emissions continue to grow at their historic pace – between 2 and 6 degrees Celsius by the end of this century relative to pre-industrial levels. To stop this development, the IPCC report argues, deep emission cuts are required. The IPCC does not argue for any specific target in temperature or emissions, but the European Union has stated that it would like to see containing global warming below an average temperature increase of 2 degrees Celsius as a global ambition. At this level, the IPCC already expects to see large environmental, humanitarian, and economic consequences.

To assess the potential impact of different abatement measures on GHG concentration levels and therefore the global temperature, we compare post-abatement emissions with three exemplary allowable emissions pathways (i.e., ranges of emissions that would still allow the world to contain global warming). McKinsey has not made any assessment or analysis of these pathways, a task that is beyond our expertise. The estimates are those of external scientific sources, including the IPCC's Fourth Assessment Report that showed pathways for CO_2 and recent multigas studies from IPCC authors[13] (Exhibit 2.1.1).

The pathway values represent the absolute annual emissions over time that would need to be achieved in order to limit the increase in global mean temperature to a certain level[14]. There are two major uncertainties in the climate system which require the use of ranges: First, there is uncertainty about which path of annual emissions leads to a particular level of GHG concentration. Second, there are uncertainties about the translation of a concentration level pathway into a temperature trajectory. Three pathways have been used:

- **A pathway that peaks at 480 ppm.** This pathway is estimated to have a 70–85 percent probability of containing global warming below the 2 degrees Celsius threshold, and an expected

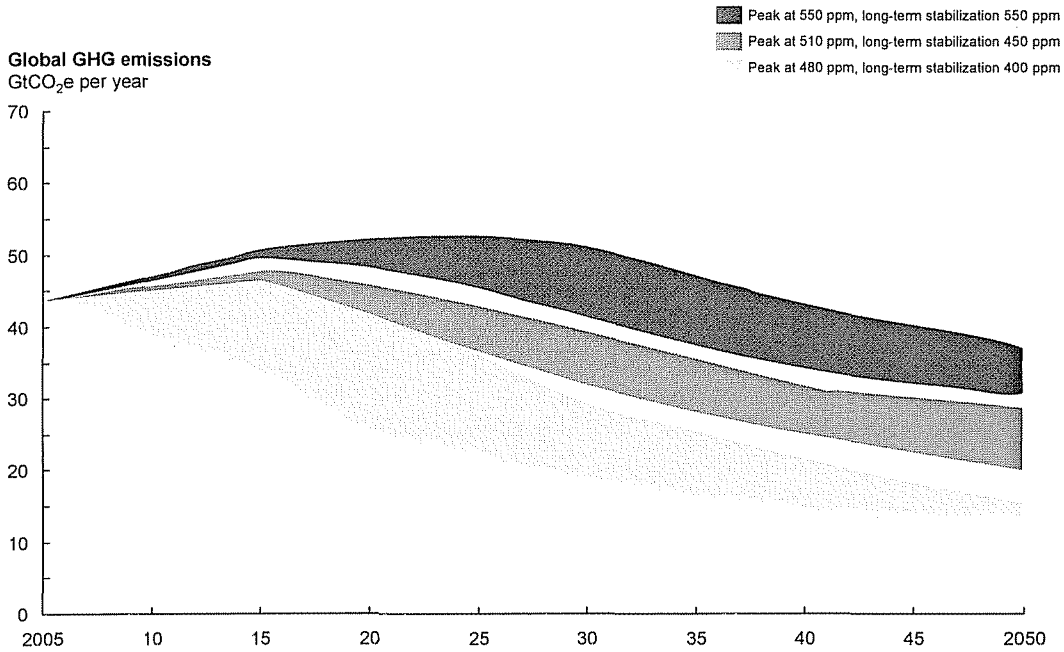
12 *Climate Change 2007, Fourth IPCC Assessment Report*, Intergovernmental Panel on Climate Change

13 We are grateful to scientists Michel den Elzen, Detlef van Vuuren, and Malte Meinshausen for their contributions to this report.

14 The stated temperature increase represents a global average with substantial variances around the globe – higher increases expected at the poles, lower increases towards the equator.

Exhibit 2.1.1

Allowable emission pathways over time



Source: den Elzen; Meinshausen; van Vuuren; Global GHG Abatement Cost Curve v2 0

temperature increase is 1.8 degrees Celsius. In this pathway emissions would peak before 2015 and concentration levels would peak at 480 ppm CO_2e between 2060 and 2070. The peaking of the concentration levels assumes that CO_2 emissions are reduced below the level of natural absorption. In this pathway, 2030 emissions would be 18–29 $GtCO_2e$ compared with 36 $GtCO_2e$ in 1990, a reduction of 20 to 50 percent during this period. In the very long term – likely around the year 2200 but there is significant uncertainty in this estimate – this pathway would achieve a stabilization level of 400 ppm if emissions constantly stay below natural absorption rates.

- **A pathway that peaks at 510 ppm.** This pathway would see emissions peak in or before 2015 and GHG concentration levels peak at 510 ppm CO_2e before 2100. This pathway is estimated to have a 40 to 60 percent probability of containing global warming below the 2 degrees Celsius threshold, and the expected temperature increase is 2.0 degrees Celsius. In this pathway, 2030 emissions are of 32–39 $GtCO_2e$. Compared to 1990 levels this represents a change in emissions between plus 8 and minus 10 percent. Again, the long-term stabilization level of 450 ppm would not be anticipated until 2200.
- **A pathway that peaks and stabilizes at 550 ppm.** In this pathway, a concentration level of 550 ppm would be reached in 2060 without overshooting (i.e., peak and long-term stabilization levels would be equal), given today's starting position. In this pathway, emissions in 2030 would reach 41-51 $GtCO_2e$ compared with 1990 emissions of 36 $GtCO_2e$. This pathway is expected to lead to a temperature increase of 3.0 degrees Celsius.

The first two scenarios are so-called *overshoot* scenarios, where GHG concentration levels peak at one level, and then in the very long term stabilize at a lower level. For this lower stabilization level to materialize, they assume global CO_2 emissions will for a long time – more than a century – remain below the *natural CO_2 absorption rate* of the climate system. Our analysis only focuses on the time period to 2030. As a result, the peak concentration levels are more relevant to compare to.

2.2 Business-as-usual emissions trajectory

Global GHG emissions have increased steadily since the Industrial Revolution. Since 1990, the reference year used in the Kyoto protocol, emissions have grown at a pace of approximately 1.6 percent a year, from 36 gigatonnes of carbon dioxide equivalents ($GtCO_2e$) in 1990 to 46 $GtCO_2e$ in 2005. Most current research forecasts that, *in the absence of major global policy action, global emissions will continue to* grow at a similar pace as they have historically, driven by world population growth and rising wealth.

Drawing from external sources widely acknowledged to have some of the most comprehensive projections of GHG emissions, we see the business-as-usual (BAU) global anthropogenic GHG emissions increasing by around 55 percent in the period from 2005 to 2030, going from 46 to 70 $GtCO_2e$[15] per year, a growth of 1.7% per year.[16] Key assumptions in the BAU case are annual GDP growth of 2.1 percent in the developed world and 5.5 percent in the developing world; global population growth of 0.9 percent per annum, comprising 0.2 percent in developed countries and 1.1 percent in the developing world, and a $60 per barrel oil price. These assumptions are taken from the International Energy Agency's (IEA) *World Energy Outlook* for 2007. The emissions baseline is subject to substantial uncertainty, mainly due to uncertainty in GDP growth and population growth assumptions as well as how carbon-intense development paths countries choose. The abatement potential and consequently the achieveable emissions development over time, is strongly linked to the baseline.

This growth in emissions already includes a certain amount of decarbonization, best described in terms of carbon productivity – the amount of GDP produced per unit of CO_2e emitted. In the period from 2005 to 2030, as the world economy is set to double, the annual carbon productivity improves by 1.2 percent annually in business-as-usual, broadly in line with historic improvements in this measure.[17] This decarbonization derives mainly from energy efficiency improvements happening under the usual course of the world economy. Details on decarbonization assumptions can be found for each of the sectors in the appendix.

Emissions fall into four broad groups of sectors that each contributed approximately one-quarter of total emissions in 2005: Power; Industry (with Petroleum and Gas, Iron and Steel, Cement, and Chemicals as large contributors); consumer-related sectors (i.e., Transport, Buildings, Waste), and land-use related sectors (i.e., Forestry and Agriculture) (Exhibit 2.2.1). Under BAU, the relative share of emissions from the first three groups will increase by a projected 2 to 3 percentage points each, while the relative share of land-use related emissions will fall from 30 percent in 2005 to an estimated 22 percent in 2030.

Our analysis also splits emissions by region (Exhibit 2.2.2). In 2005, the developed world contributed approximately 40 percent of total emissions, the developing world approximately 56 percent, with the remaining 4 percent coming from global air and sea transportation that in line with international agreements is not attributed to a specific region. Under BAU, the developed world will contribute 32 percent of the total by 2030, the developing world 63 percent, and global air and sea transport 5 percent.

In per capita terms, 2005 emissions were approximately 14 tCO_2e per year in the developed world and 5 tCO_2e per year in the developing world. By 2030, per capita emissions in the developed world are expected to remain more than twice as high as those in the developing world (16 and 7 tCO_2e per year, respectively), despite the fact that expected annual growth in developed countries of 0.7 percent on average is only one third of the 2.2 percent growth rate in developing countries.

15 Our total BAU emissions in 2005 of 46 $GtCO_2e$ per year are slightly lower than the value from the IPCC AR4 of 49 $GtCO_2e$ per year. This gap is driven by different estimates of emissions from fossil fuel combustion (~1 Gt difference between the IPCC and the IEA); for non-CO_2 gases (~1 Gt difference between the IPCC and the US EPA); in LULUCF emissions (~1 Gt difference between the IPCC and Houghton/UNFCCC/Hooijer). The BAU emissions projection to 2030 is in line with IPCC's high-growth A1 Fossil Intensive (A1FI) scenario.

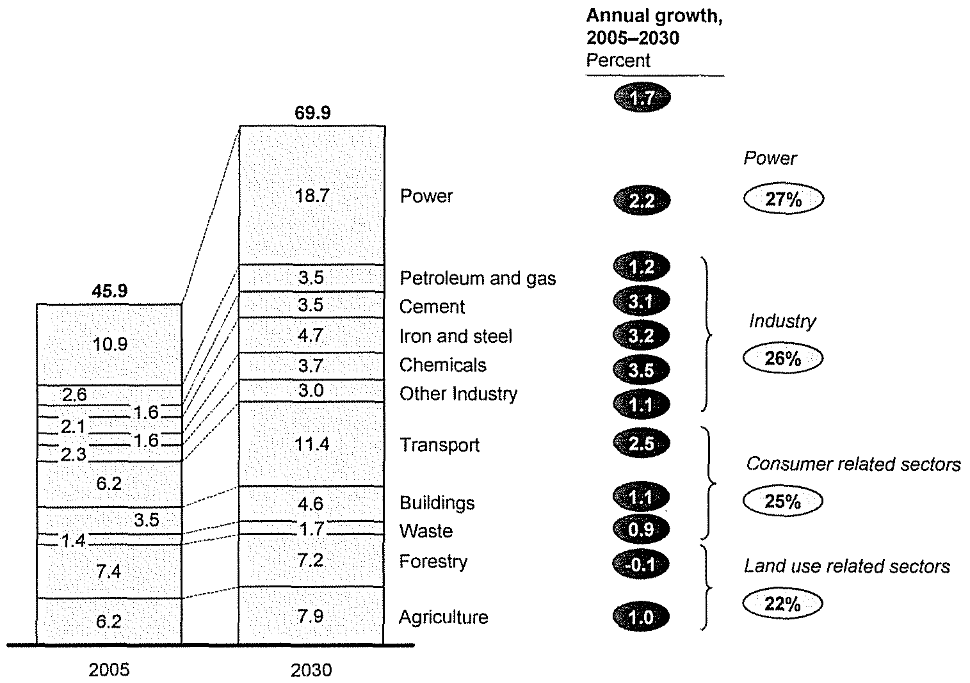
16 For our BAU analysis, we draw directly from a range of expert sources: the International Energy Agency (IEA) for CO_2 emissions from fossil-fuel combustion; Houghton 2003 revised, UNFCCC and IPCC for land use, land-use change and forestry (LULUCF) emissions including peat, and the US Environmental Protection Agency (EPA) for emissions of non-CO_2 GHGs. For the Industry sectors, we constructed emission baselines leveraging IEA data wherever possible.

17 We measure carbon productivity as the ratio of global GDP to tonnes of global GHG emissions.

Exhibit 2.2.1

Business-as-usual emissions split by sector in 2005 and 2030

$GtCO_2e$ per year

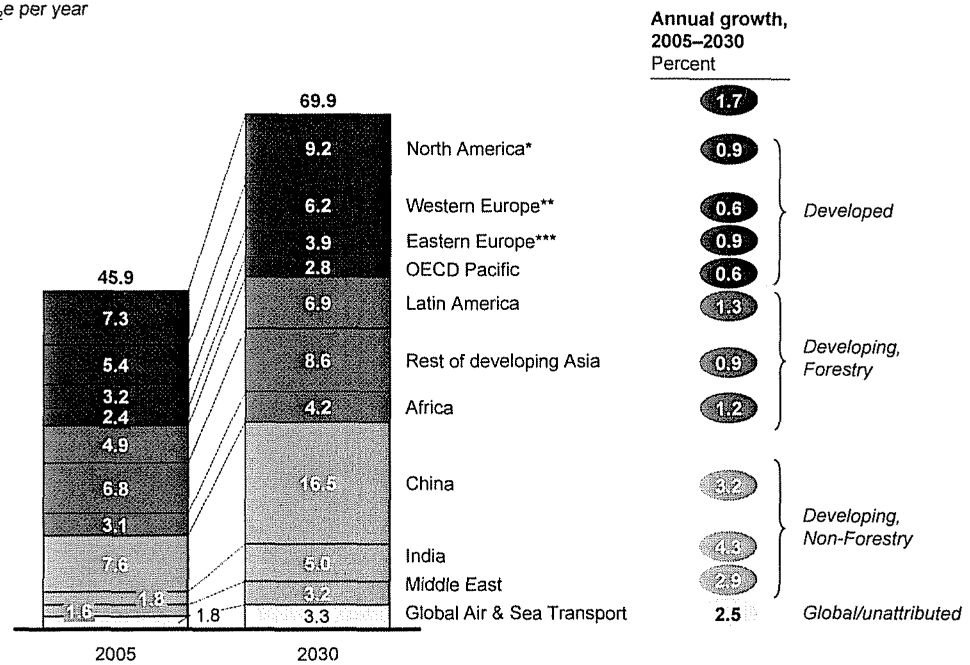


Source: Houghton; IEA; IPCC; UNFCCC; US EPA; Global GHG Abatement Cost Curve v2.0

Exhibit 2.2.2

Business-as-usual emissions split by region in 2005 and 2030

$GtCO_2e$ per year



* US and Canada
** EU27, Andorra, Iceland, Lichtenstein, Monaco, Norway, San Marino, and Switzerland
*** Non-OECD Eastern Europe and Russia.
Source: Houghton; IEA; IPCC; UNFCCC; US EPA; Global GHG Abatement Cost Curve v2.0

3. The GHG abatement potential

Our research finds that there is *potential* by 2030 to cut emissions by ~35 percent compared with 2005 levels and 70 percent compared with the levels that we would see in 2030 if the world failed to take action to curb emissions (a BAU development). If this full potential was captured, emissions would peak at 480 ppm and then start to decrease. As described in Chapter 2, this GHG concentration pathway is projected to very likely hold global warming below the 2 degrees Celsius threshold.

It is, however, one thing to have the *potential* to make deep cuts in GHG emissions; it is another for policy makers to agree on and implement effective emission reduction policies, and for companies, consumers and the public sector to take action to make this reduction a reality. The abatement potential we identify in the cost curve pushes the envelope in terms of what the world could achieve if each opportunity was pursued aggressively across regions (see section 6.1 of this report for a description of five implementation scenarios) and represents a huge challenge, capturing all the opportunities would entail change on a huge scale. In Transport, for instance, the assumption in our study is that 42 million hybrid vehicles (including plug-ins) could be sold by 2030 – that's a full 40 percent of all new car sales. In Forestry, the assumption is that we could until 2030 avoid the deforestation of 170 million hectares, equivalent to twice the land area of Venezuela, and plant new forests on 330 million hectares of currently marginal land – the equivalent of foresting much of India. In Power, the share of low-carbon generation technologies such as renewables, nuclear and carbon capture and storage could rise to about 70 percent of global electricity production from 30 percent in 2005. After careful analysis, we believe such change would be feasible if there was concerted global action to go after each opportunity – this is the potential we aim to portray in our curve – but clearly implementing all of the opportunities on our curve to their full extent represents a massive change.

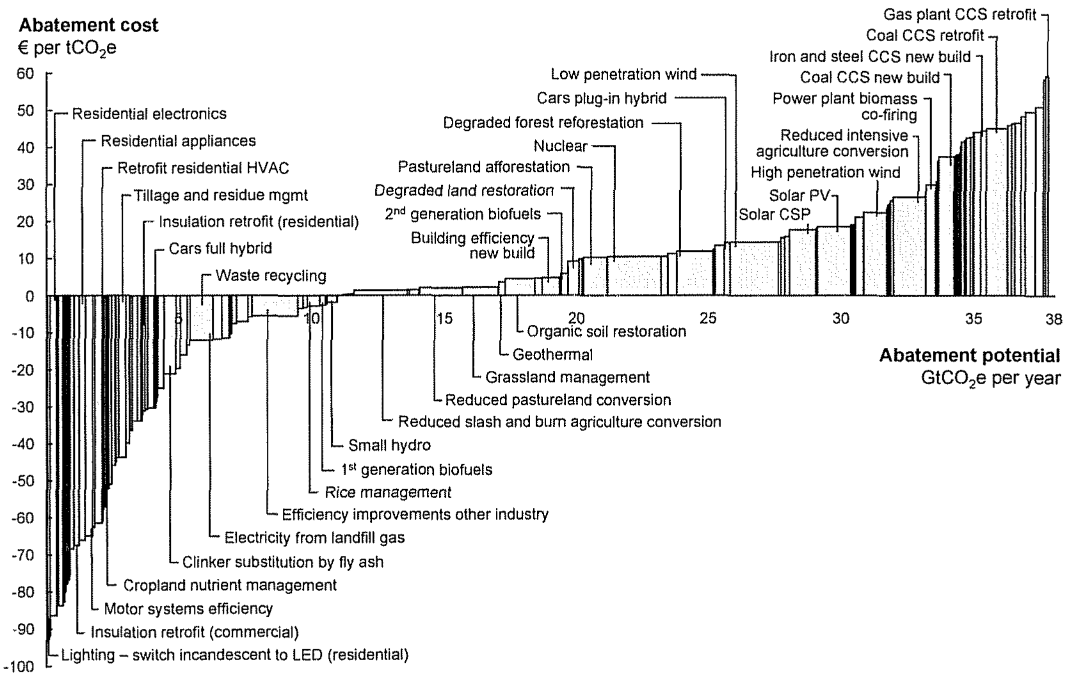
Another way to illustrate the challenge is to look at carbon productivity – the amount of GDP produced per unit of CO_2 emitted. In the period from 2005 to 2030, emissions would need to decrease by 35 to 50 percent to attain the 480 ppm peak pathway likely to achieve the 2 degrees Celsius threshold. As the world economy is set to more than double during the same time period, this implies almost quadrupling the global carbon productivity. This corresponds to increasing the annual global carbon productivity gains from 1.2 percent in the BAU, to 5 to 7 percent. In per capita terms – a third way to look at the challenge – reaching the emissions pathway that peaks at 480 ppm means reducing emissions from 7.1 tCO_2e per capita in 2005 to 3.1 tCO_2e per capita in 2030.

Potential exists to contain global warming below 2 degrees Celsius – but not much more

Our research has identified that technical abatement measures costing less than €60 per tCO_2e – the focus of most of our analysis – have the potential to deliver abatement of some 38 $GtCO_2e$ per year in 2030 (Exhibit 3.0.1). If the entire potential below this cost threshold was realized, 2030 emissions would be 55 percent lower than the BAU emissions of 70 $GtCO_2e$ per year. Emissions would then be 30 percent lower than the levels that prevailed in 2005, and about 10 percent below 1990 emissions. This is without accounting for potential rebound effects, which we have not modeled. A rebound effect, for instance, would be if resources freed up by energy savings would be used for alternative, potentially high-carbon consumption.

Exhibit 3.0.1

Global GHG abatement cost curve beyond business-as-usual – 2030



Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €60 per tCO_2e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play
Source: Global GHG Abatement Cost Curve v2 0

The cost curve shows a high degree of fragmentation among individual abatement options, but there are three major categories of measures:

- **Energy efficiency (opportunity of 14 $GtCO_2e$ per year in 2030).** There are a large number of opportunities to improve the energy efficiency of vehicles, buildings, and industrial equipment, thereby reducing energy consumption. More fuel-efficient car engines, better insulation of buildings, and efficiency controls on manufacturing equipment are just a few of the possibilities. If all energy efficiency opportunities identified in our model were captured, annual growth in global electricity demand between 2005 and 2030 would be reduced from 2.7 percent per year in the case of BAU to about 1.5 percent.[18]

18 Electricity demand annual growth increases back to 2.0 percent when taking additional electricity demand from carbon capture and storage (CCS) and transport into account.

- **Low-carbon energy supply (opportunity of 12 $GtCO_2e$ per year in 2030).** There are many opportunities to shift energy supply from fossil fuels to low-carbon alternatives. Key examples include electricity production from wind, nuclear, or hydro power, as well as equipping fossil fuel plants with carbon capture and storage (CCS), and replacing conventional transportation fuel with biofuels. If these low-carbon alternatives were to be fully implemented, we estimate that they have the potential to provide about 70 percent of global electricity supply by 2030 compared with just 30 percent in 2005;[19] and that biofuels could provide as much as 25 percent of global transportation fuel by 2030. This would constitute a major shift in global energy supply. Several of these low-carbon energy technologies are too expensive today to deploy on a large scale without financial incentives, emphasizing the need to provide sufficient support to make them travel down the learning curve if policy makers want them to contribute to abatement on a big scale.[20]
- **Terrestrial carbon – forestry and agriculture (opportunity of 12 $GtCO_2e$ per year in 2030).** Forests and soils act as natural sinks for carbon. Halting ongoing tropical deforestation, reforesting marginal areas of land, and sequestering more CO_2 in soils through changing agricultural practices would increase carbon sequestration. This would lead to negative net emissions of CO_2e into the atmosphere from these sectors in the period we have studied (implying that more carbon is stored than is released from these sinks), a major abatement opportunity versus the BAU in which deforestation continues. However, capturing these opportunities would be highly challenging. More than 90 percent of them are located in the developing world, they are tightly linked to the overall social and economic situation in the concerned regions, and addressing the opportunities at this scale has not before been attempted. Our estimate of the feasibility and cost of this opportunity is therefore subject to significant uncertainty. We also note that terrestrial carbon opportunities are temporary in nature because the sinks would saturate between 2030 and 2050, so that, at the end of this period, there would be few additional areas of marginal land left available for re-forestation.

What comes beyond the €60 per tCO_2e on the cost curve? We estimate that another 3–6 $GtCO_2e$ per year of technical abatement opportunities in these three categories are available at a cost of between €60 and €100 per tCO_2e. This range of higher cost of abatement has not been the focus of our research, and the level of uncertainty in our estimates is much higher than for the lower cost opportunities. It is clear, however, that in many of the sectors there is a breaking point where abatement increases in complexity and cost. In the *land-use based sectors* this breaking point is reached when all currently unused and marginal land is being used. Pushing afforestation beyond this point quickly becomes more expensive as the land value quickly increases for land that is productively used today. As a result, we do not assume any additional Forestry potential between €60 and €100 per tCO_2e. In Agriculture, there are some opportunities in this cost range, e.g., feed conversion and intensive grazing. In *heavily infrastructure-dependent sectors*, a similar breaking point occurs when all opportunities to change the specification of new infrastructure to low-carbon are exhausted. Additional emission reduction then requires retrofitting existing infrastructure, or alternatively retire existing infrastructure before the end of its lifetime. The costs of both types of opportunity typically increases quickly as younger infrastructure gets retired or older infrastructure gets retrofitted. Still, there are early retirement and retrofit opportunities at a cost of €60 and €100 per tCO_2e in both the Power and Industry sectors. There are also some specific technologies in this cost range, e.g., the gasification of biomass or membrane separation in Petroleum and Gas. In *consumer-related sectors*, all new infrastructure in Transport and Buildings is already addressed at

19 This would include renewable sources (wind, solar, hydro, biomass, geothermal, tide and wave), nuclear, as well as fossil fuels with CCS.

20 We have only included technologies in our curve that we see as technologically proven, that could credibly have costs lower than €60 per tCO_2e abated in 2030, and that we can envisage having a major abatement impact by 2030. There are also many technologies that did not pass our criteria to be included in the curve since they are too early in their development stage, but that could also have a major impact in the period after 2030.

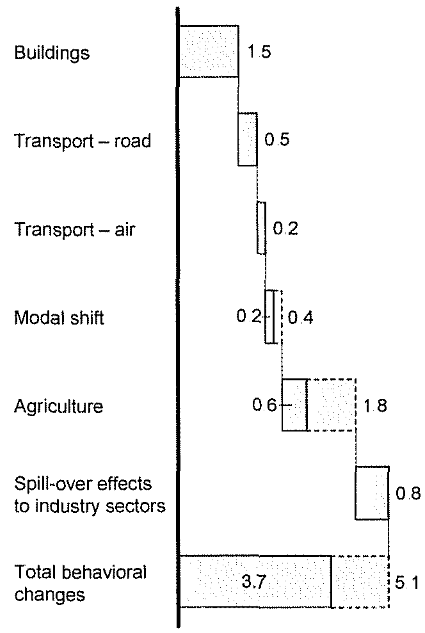
costs below €60 per tCO_2e, and we do not assume the early retirement of assets owned by individual consumers. However, selected more aggressive assumptions could be made in the penetration of Building levers at higher cost: higher penetration of passive housing, additional retrofitting of commercial building envelopes, increased penetration of solar water heating and the large-scale rollout of geothermal heat pumps. For Transport, electric vehicles and increased penetrations of hybrids for passenger cars, and hybrids for commercial vehicles could increase abatement. Pushing biofuels even further would involve upgrading engines to allow for a higher biofuels share, thus make it a higher cost option. Finally, in the *waste sector* there is no further potential, given full penetration of recycling and composting of waste at a cost of less than €60 per tCO_2e.

An additional abatement opportunity is behavioral change. In an optimistic case – and there is a high degree of uncertainty in these estimates – this could yield between another 3.5 $GtCO_2e$ and 5 $GtCO_2e$ per year of abatement in 2030. Key opportunities include reducing business and private travel, shifting road transport to rail, accepting higher domestic temperature variations (reducing heating/ cooling), reducing appliance use, and reducing meat consumption. Changing behavior is difficult, and the abatement realized would depend heavily on whether, and to what extent, policy makers establish effective incentives. Exhibit 3.0.2 shows some illustrative examples of possible changes in behavior – and their emissions impact – without any judgment on whether these behavioral changes should be incentivized or not.

Exhibit 3.0.2

Examples of behavioral changes beyond technical abatement measures

$GtCO_2e$ per year; 2030



Illustrative calculation assumptions

Buildings:
- -2°C change in HVAC, i.e., -12% energy use
- -20% for residential water heating; lighting; appliances
- -20% floor space for new builds

Transport – road:
- Consumers: smaller cars, driving more efficiently, driving less
- Commercial transport: increased vehicle capacity or utilization, improved route planning, etc.

Transport – air:
- -20% air travel

Modal shift:
- -5-10% road transport by switching to rail, bus, walk or cycle

Agriculture:
- Meat consumption for developed world -20%; ROW -10% (after 40% consumption increase towards 2030)
- Replace 0-50% consumption of ruminants** with other meat

Spill-over effects to industry sectors:
- Cement: -15% (buildings)
- Iron & Steel: -10% (buildings); -5% (transport)
- Chemicals: - 5% (buildings); -5% (transport)

* Behavioral effects accounted for after implementation of all other levers
** Beef/cattle, sheep, goats
Source: Global GHG Abatement Cost Curve v2 0

Comparing Versions 1 and 2 Global GHG Cost Curves

The world has changed significantly in the two years since the publication of the first version of our Global Cost Curve in early 2007. Economic growth has accelerated in the developing world, raising the average annual GDP growth forecast from 3.2 to 3.6 percent; climate change science has advanced, resulting in calls for even more stringent emissions reductions to restrict temperature increases; energy prices have risen, a long-term trend according to the International Energy Agency; and technology has developed. In the mean time, McKinsey has deepened its knowledge of GHG cost curves with the publication of seven national cost curves in collaboration with various industry associations, companies and institutions.

Our updated research incorporates all these elements. The key differences in results between the first version of the cost curve and the curve that we present in this study are

- For 2030, BAU emissions have increased from 58 to 70 $GtCO_2e$ per year globally, primarily due to higher expected economic growth
- The total identified abatement potential has increased to 38 $GtCO_2e$ per year in 2030 (up from 27 $GtCO_2e$), largely due to the higher BAU emissions and the higher cost cut-off (€60 per tCO_2e in version 2 compared to €40 per tCO_2e in version 1), but also due to an number of new insights over the last two years: The main contributors to the increased abatement potential are the Power sector with +4 $GtCO_2e$ per year, mainly from a higher baseline (+ 2 $GtCO_2e$ per year), higher potential from early retirement and a more positive view on renewables growth potential; and Agriculture with about +3.5 $GtCO_2e$ per year with carbon sequestration levers now fully included in the analysis. In the Forestry sector, the assessment is now based on a simplified but explicit bottom-up modeling and abatement potential has increased by little more than +1 $GtCO_2e$ per year.
- These two counteracting effects lead to similar emissions after abatement at 32 $GtCO_2e$ per year
- The average cost of abatement stays relatively constant; up from €2 to €4 per tCO_2e with higher energy prices assumptions** counteracting the higher cut-off cost

* We went from analyzing 6 World regions to 21, with each G8+5 country modeled separately

** Version 1 relied on IEA's World Energy Outlook (WEO) 2005 for its oil price forecast ($40 per barrel), while version 2 relies on WEO 2007 (oil price forecast of $60 per barrel)

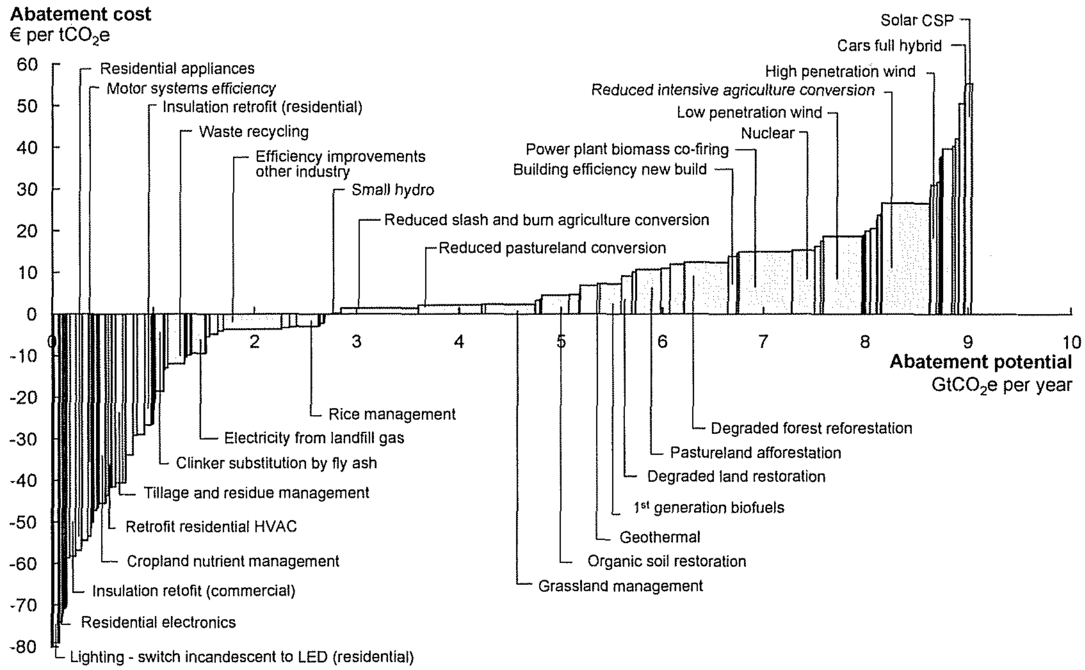
What could be done until 2015?

This report looks at abatement in a 2030 time frame, reflecting our belief that mitigation action requires a long-term outlook to prioritize different opportunities effectively. As explained earlier, the 2030 cost curve displays the abatement potential from different opportunities if each is successfully pursued in the period from 2010 to 2030, and the weighted average cost over the 2010 to 2030 time period of each opportunity. But what does the curve look like in a shorter time horizon? Exhibit 3.0.3 shows the global 2015 curve. The horizontal axes of this curve represents the abatement potential from each opportunity, if it was successfully pursued in the 2010 to 2015 time period, and the cost is the weighted average cost in the same time period.

What are the big differences between the 2015 and the 2030 curves? First, the overall abatement volume clearly is much lower – around 9 $GtCO_2e$ per year. In fact, it grows in an approximately linear manner over time.

Exhibit 3.0.3

Global GHG abatement cost curve beyond business as usual – 2015



Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €60 per tCO_2e if each lever was pursued aggressively It is not a forecast of what role different abatement measures and technologies will play

Source: Global GHG Abatement Cost Curve v2 0

Second, the proportional contribution of the sectors differs significantly, with approximately 50 percent of measures related to changes in land use (Forestry and Agriculture), reflecting that these opportunities can be ramped up relatively faster than solutions that have a substantial infrastructure component such as Buildings (which account for only 7 percent of abatement potential in 2015 versus 9 percent in 2030) and Power (18 percent versus 26 percent in 2030). In the case of the latter, most of the potential stems from biomass co-firing, which can very easily be ramped up in existing coal-fired power plants.[21] The contribution of industry stays stable at 19 percent from 2015 to 2030.

Third, emerging technologies such as solar and CCS do not yet contribute substantial abatement volumes and are still expensive given their early stage of development. In the Power sector, as an example, emerging technologies contribute less than 2 percent of total abatement in 2015 at an average cost of €60 per tCO_2e. In 2030, that share increases to 11 percent and costs plummet to €28 per tCO_2e.

21 Without co-firing, the power share would be only 11 percent of the total abatement opportunity in 2015

3.1 Sector view: Three types of sectors with different characteristics

Our research examined abatement measures across 10 sectors. The detailed perspectives per sector are available in the appendix of this report. In this section, we summarize the overall observations from a sector perspective. From an emissions perspective, there turn out to be three categories of sectors, with very different abatement characteristics, and therefore very different implementation challenges (Exhibits 3.1.1 and 3.1.2):

1. **Energy-supply and Industrial sectors (about 17 $GtCO_2e$ per year opportunity, 20 to 55 percent reduction from 2030 BAU).** Emissions in this category are released into the atmosphere from a relatively small number of large point sources, such as power plants, petroleum refineries, steel mills and chemical plants. Emissions are concentrated to the developed world, China and India. Abatement opportunities typically consist of energy efficiency, shifting fuels, or shifting to low-carbon alternatives when building new infrastructure. In some sectors, for instance the Power sector, a significant share of the 2030 opportunity resides in technologies that need to improve their cost competitiveness considerably. The companies in these industries are comparatively large and used to making investment decisions based on regulatory incentives.

   Looking at the available abatement potential, there are opportunities to reduce emissions in these sectors by approximately 17 $GtCO_2e$ per year in 2030 – 45 percent of the total abatement potential in our cost curve. This abatement corresponds to a 20 to 55 percent reduction from the 2030 BAU, depending on the sector. For the Power and Petroleum and gas sectors, this means a reduction of 15 to 60 percent compared to 2005 – when accounting for the demand reduction from consuming sectors in addition to the abatement potential within each sector. For the industrial sectors emissions would still increase by 30 to 60 percent, as the underlying sector growth rates are very high.

   In terms of challenges to achieve the abatement potential, we see them primarily being around technology (scaling up emerging technologies and making travel down the learning curve), around cost, and around avoiding competitive distortions due to different regulation between sectors and countries.

2. **Consumer related sectors – Transport, Buildings and Waste sectors (approximately 8 $GtCO_2e$ per year opportunity, 25 to 90 percent reduction from 2030 BAU).** Emissions in these sectors come from literally billions of small emitters – individual houses and vehicles. Geographically, the opportunities are spread between the developed and the developing world. Abatement opportunities are to a very high degree related to energy and fuel efficiency, and many of them hold a net economic benefit if the impeding agency and other issues could be overcome.

   The overall abatement potential is 8 $GtCO_2e$ per year in 2030 – 22 percent of the total abatement potential in our cost curve. This abatement corresponds to 25 to 90 percent of the 2030 BAU for each sector. Relative to 2005, emissions would still increase by ~30 percent in the Transportation sector and ~10 percent in the Buildings sector, due to the high underlying growth, whereas it would decrease by 90 percent in Waste.

   The implementation challenge in these sectors is primarily to design effective policy to get access to the energy efficiency opportunities. This typically involves policy to overcome the frequent agency and awareness issues in these sectors.

3. **Terrestrial carbon – Forestry and Agriculture sectors (some 12 $GtCO_2e$ per year opportunity, 60–110 percent reduction from BAU).** Emissions in Forestry come from deforestation and peat; in Agriculture, from livestock and fertilizer use. In both cases the emissions come from billions of small sources, mainly concentrated in the developing world; for Forestry specifically in tropical rainforest regions. These emissions are difficult to measure and monitor, so the uncertainty is high even in the baseline emission estimates.

Exhibit 3.1.1

Sector split – BAU emissions and abatement potential

Indirect emissions and abatement potential

	2030 BAU GtCO$_2$e per year (indirect)	2030 BAU GtCO$_2$e per year	Abatement potential 2030 GtCO$_2$e per year (indirect)	Abatement potential 2030 GtCO$_2$e per year	Emissions reduction relative to 2030 BAU Percent	Emissions reduction relative to 2005 Percent	
Power		18.7		10.0	-53	-60	**Power** ~10 GtCO$_2$e potential -53% vs. 2030 BAU -60% vs. 2005
Petroleum and gas	3.5	3.9	0.9	1.1	-28	-14	**Industrial sectors** ~7 GtCO$_2$e potential -15 to -40% vs. 2030 BAU -15 to +60% vs. 2005
Cement	3.5	3.9	1.0	1.0	-25	58	
Iron and steel	4.7	5.5	1.1	1.5	-27	59	
Chemicals	3.7	5.3	1.7	2.0	-38	39	
Other industry	3.0	10.5	0.3	1.7	-17	33	
Transport		11.4		3.2	-28	32	**Direct consumer related** ~8 GtCO$_2$e potential -30 to -90% vs. 2030 BAU -85 to +35% vs. 2005
Buildings	4.6	12.6	1.3	3.5	-28	11	
Waste		1.7		1.5	-87	-84	
Forestry		7.2		7.8	-109	-109	**Land use related** ~12 GtCO$_2$e potential -60 to -110% vs. 2030 BAU -50 to -110% vs. 2005
Agriculture		7.9		4.6	-59	-48	
Total		70		38	-54	-30	

Source: Global GHG Abatement Cost Curve v2.0

Exhibit 3.1.2

Abatement potential by sector and key levers

	Abatement potential GtCO$_2$e per year, 2030	Key levers	Abatement potential
Power	10.0	• Renewables (Solar, wind, biomass) • Nuclear • CCS	4.0 2.0 1.7
Petroleum and gas	1.1	• CCS • Energy efficiency	0.4 0.3
Cement	1.0	• Clinker substitution • Alternative fuels	0.5 0.3
Iron and steel	1.5	• Energy efficiency • Co-generation	0.5 0.3
Chemicals	2.0	• CCS • Motor systems	0.4 0.3
Other industry	1.7		
Transport	3.2	• ICE improvement, hybrids, EV • Biofuels	1.9 0.5
Buildings	3.5	• New build efficiency packages • Lighting and lighting controls	0.9 0.7
Waste	1.5	• Waste recycling • Land fill gas direct use	0.9 0.2
Forestry	7.8	• Avoided deforestation • Afforestation/reforestation	3.6 2.4
Agriculture	4.6	• Grassland management • Organic soil restoration	1.3 1.1
Total	38		

Note: This is an estimate of the maximum potential of all technical GHG abatement measures below €60 per tCO$_2$e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play

Source: Global GHG Abatement Cost Curve v2.0

The key abatement measures in Forestry sector are avoiding deforestation, reforestation, afforestation, and improved forest-management practices.[22] For Agriculture four categories of abatement levers have been identified: land restoration (e.g., re-establishing high water tables to avoid decomposition); cropland management (including crop rotation, cover crops, tillage reduction, nutrient management); pastureland management (e.g., increased grazing intensity); and livestock management.

The total Forestry abatement potential has been estimated at 7.8 $GtCO_2e$ per year in 2030 – corresponding to approximately 110 percent of 2030 BAU emissions[23]. In Agriculture, we see the potential to abate 4.6 $GtCO_2e$ per year in 2030, leaving emissions 60 percent lower than BAU in 2030 and about 50 percent lower than in 2005.

The uncertainty about the abatement potential in both sectors is much higher than for the other sectors given the great implementation challenges. Deforestation projects are notoriously difficult to make effective and there are significant problems of leakage, as well as in measurement and monitoring. In Agriculture, educating and mobilizing billions of farmers around the world to change their daily practices is similarly challenging. Capturing abatement in these sectors would directly impact billions of people, primarily in developing countries, requiring to successfully handle social change and building institutional capacity at the same time.

3.2 Regional view: Three types of regions with different characteristics

The abatement potential varies considerably between regions and countries, both in relative and absolute terms (Exhibit 3.2.1). Three major drivers explain the differences: the sector split of a country's economy, the carbon intensity starting point of each sector in a specific country, and the country's economic growth. On the latter driver, economic growth increases the availability of low-cost abatement opportunities relative to BAU because rapid economic growth typically involves the large-scale building of new infrastructure, which provides more low-cost abatement opportunities than retrofitting existing infrastructure with higher efficiency technologies.

Countries and regions fall into three broad groupings in our cost curve analysis in terms of their abatement potential:

1. **Developed regions (about 12 $GtCO_2e$ per year opportunity, 45–55 percent reduction from 2030 BAU).** Emissions in developed regions accounted for 18 $GtCO_2e$ in 2005, an amount that grows at 0.8 percent per year to reach 22 $GtCO_2e$ in 2030 in the BAU case. Developed regions can typically reduce their emissions by 45 to 55 percent of the BAU level in 2030, which is equivalent to a 35 to 45 percent reduction from the 2005 emissions level. The overall abatement potential in developed countries is 12 $GtCO_2e$ per year in 2030 – 31 percent of the total abatement potential in our cost curve.
2. **Developing Forestry regions (some 13 $GtCO_2e$ per year opportunity, 65–70 percent reduction from 2030 BAU).** Developing regions with very large forest areas accounted for 15 $GtCO_2e$ of emissions in 2005, growing at 1.1 percent per year to reach 20 $GtCO_2e$ in 2030 in the BAU case. These regions can typically reduce their emissions by between 65 and 70 percent of BAU in 2030.

22 Reforestation means planting forest over degraded land with no food or feed production value. Afforestation means planting forest over marginal pastureland and marginal cropland. No assumptions have been made about reforesting or afforesting land with major food or feed value

23 A value over 100 percent means a net reforestation, i.e. that more carbon is stored in Forests than is released

Exhibit 3.2.1

Regional split – BAU emissions and abatement potential

	BAU emissions 2030 $GtCO_2e$ per year	Abatement potential 2030 $GtCO_2e$ per year	Emissions reduction relative to 2030 BAU Percent	Emissions reduction relative to 2005 Percent	
North America*	9.2	5.1	-55	-43	Developed regions -45 to -55% vs. 2030 BAU -35 to -45% vs. 2005
Western Europe**	6.2	3.2	-51	-43	
Eastern Europe***	3.9	1.9	-49	-37	
OECD Pacific	2.8	1.4	-51	-43	
Latin America	6.9	4.5	-66	-52	Developing regions, forestry -65 to -70% vs. 2030 BAU -50 to -60% vs. 2005
Rest of dev. Asia	8.6	5.7	-67	-58	
Africa	4.2	2.8	-68	-57	
China	16.5	8.4	-51	7	Developing regions, non forestry -40 to -55% vs. 2030 BAU +5 to +35% vs. 2005
India	5.0	2.7	-53	33	
Middle East	3.2	1.4	-43	16	
Global air & sea travel	3.3	0.8	-24	43	
Total	70	38	-54	-30	

* United States and Canada
** Includes EU27, Andorra, Iceland, Lichtenstein, Monaco, Norway, San Marino, Switzerland
*** Russia and non-OECD Eastern Europe
Source: Global GHG Abatement Cost Curve v2.0; Houghton; IEA; UNFCCC; US EPA

This would leave emissions between 50 and 60 percent lower than levels in 2005. The large abatement potential is due to the fact that the opportunity for abatement in the Forestry sector is above 100 percent (i.e., it is possible to reforest/afforest larger areas than are being deforested by 2030), and because Forestry accounts for up to 50 percent of total 2030 BAU emissions in countries such as Brazil and Indonesia. Without Forestry abatement opportunities, overall emissions would only be about 30 percent lower than 2030 BAU, and some 15 percent less than 2005 emissions. The overall abatement potential in developing Forestry regions is 13 $GtCO_2e$ per year in 2030 – 35 percent of the total abatement potential in our cost curve.

3. **Developing non-Forestry regions (approximately 12 $GtCO_2e$ per year opportunity, 40–55 percent reduction from 2030 BAU).** These regions represented 11 $GtCO_2e$ in 2005 growing at 3.3 percent per year to reach 25 $GtCO_2e$ in 2030 in the BAU case. These regions, which include countries such as China and India, can typically reduce emissions 40 to 55 percent compared to BAU in 2030. However, rapid economic growth still mean that 2030 emissions after abatement would be between 5 and 35 percent higher than 2005 emissions. The overall abatement potential in these regions is 12 $GtCO_2e$ per year in 2030 – 33 percent of the total abatement potential in our cost curve.

If we split the abatement potential in 2030 by regions, we find that two-thirds of the total opportunity (67 percent) is available in the developing world, and about one-third (31 percent) in developed countries. The remaining 2 percent is in global air and sea transport, which is not attributed to individual countries. The reasons for this split are that a large share of 2030 BAU emissions come from the developing world (64%), but also because the emissions in the developing world unproportionally come from the Forestry and Agriculture sectors with a high relative abatement potential. Looking at the split in terms of regions, 49 percent of the potential resides in Asia, 25 percent in the Americas, 14 percent in Europe, and 12 percent in the rest of world. This distribution starkly demonstrates the importance of a global effort to reduce emissions at the lowest-possible cost, regardless who pays for these reductions.

Turning to per capita emissions, we find that these evolve very differently in different regions of the world in BAU, and show only minor convergence after abatement measures are implemented (Exhibit 3.2.2). In developed countries, BAU per capita emissions would rise from 13.7 tCO_2e per capita in 2005 to 16.1 tCO_2e per capita in 2030, a compound annual growth rate of 0.7 percent. With abatement, emissions per capita can be reduced to 7.7 tCO_2e per capita in 2030. In developing countries with a significant share of forestry – our second grouping – BAU emissions would decrease from 6.2 tCO_2e in 2005 to 5.8 tCO_2e per capita in 2030, a 0.2 percent annual rate of decrease. Abatement would bring this value down to 1.9 tCO_2e per capita in 2030. In "other developing countries", including India and China, BAU emissions would grow from 4.0 tCO_2e per capita in 2005 to 7.4 tCO_2e per capita in 2030, an annual rise of 2.4 percent. A level of 3.7 tCO_2e per capita can be achieved in 2030 by pursuing abatement measures. It is noteworthy that, in BAU, some developing countries (e.g., China) would have higher per capita emissions than the developed world (e.g., Western Europe) by 2030. The remaining differences between regions after abatement measures have been taken reflect remaining differences in lifestyles (e.g., floor space in the typical house per person; distance travelled per person and year). Our research concentrates only on what can be done to reduce emissions from levers that do not affect the lifestyle of individuals, and therefore have not assumed any convergence of lifestyle beyond what is already assumed in the BAU.

Exhibit 3.2.2

Emissions per capita development

tCO_2e per capita per year

	2005	2030 BAU	2030 emissions after abatement	Reduction relative to 2030 BAU Percent	Reduction relative to 2005 Percent
North America*	22.2	23.0	10.3	-55	-53
Western Europe**	9.4	10.7	5.3	-51	-44
Eastern Europe***	13.7	19.3	9.8	-49	-29
OECD Pacific	11.9	14.7	7.2	-51	-40
Latin America	8.9	9.7	3.3	-66	-63
Rest of dev. Asia	6.4	6.5	2.2	-67	-66
Africa	3.5	2.8	0.9	-68	-74
China	5.8	11.3	5.6	-51	-3
India	1.6	3.4	1.6	-53	0
Middle East	8.2	10.9	6.2	-43	-24
Global	7.1	8.6	3.9	-54	-45

* United States and Canada
** Includes EU27, Andorra, Iceland, Lichtenstein, Monaco, Norway, San Marino, Switzerland
*** Russia and non-OECD Eastern Europe
Source: Global GHG Abatement Cost Curve v2.0; Houghton; IEA; UNFCCC; US EPA

3.3 Brief outlook to 2050

As explained above, emissions would need to decrease by 35 to 50 percent in the period from 2005 to 2030 to attain a pathway likely to achieve the 2 degrees Celsius threshold, according to the IPCC authors we have consulted. As the world economy is set to double during the same time period, this implies almost quadrupling the global carbon productivity (measured as the amount of GDP output per unit of emissions) or 5 to 7 percent of annual improvement on annual basis, compared to a 1.2 percent increase in the business-as-usual development. Our bottom-up research has confirmed that such an improvement is possible – but challenging – on a 2030 time horizon.

If current climate-science estimates hold true, we will again need to repeat a similar carbon productivity improvement in the period from 2030 to 2050: emissions again need to decrease by approximately 50 percent, whereas the global economy will presumably grow considerably. While our bottom-up work has not focused on this time period, it does provide one important observation: If the pace of improvement in global carbon productivity that was possible between 2020 and 2030 – 5.7 percent per year – can be maintained in the 2030 to 2050 period, this would get the world economy to emission levels very close to those required according to current climate science.

4. Energy savings could largely pay for upfront abatement investments

The question of how much tackling climate change is going to cost is a recurrent issue in today's global discussion about how to transition to a low-carbon economy. How large will capital investments need to be? Which sectors offer the highest returns on those capital outlays? Answering such questions is one of the main objectives of our research and our analysis allows us to assess not only the cost but also the opportunity of investing in carbon abatement. Many of the measures we have identified can be captured at a relatively low cost and many would even produce a positive net return. In aggregate, our research indicates that future energy savings compensate for a huge share of the initial investments of an ambitious abatement drive, if the most cost-effective abatement options are pursued. It also demonstrates how much can be saved through policy that incentivizes the lowest cost alternatives. As mentioned in previous chapters, this is not to say that the implementation of such an abatement program will be easy. On the contrary, as described in Chapter 3, it will require a significant mobilization challenge to capture the opportunities that we have identified. It is also likely that shortfalls in realizing the low cost options will mean that higher cost alternatives will have to be pursued. There will also be transaction and program costs as well as dynamic macro-economic effects that we have not included in our analysis.

In order to bring clarity to the issues of costs and investments, we use two financial measures – the abatement cost and the abatement investments – each of them shedding a specific light on the economics of climate change.

- The abatement cost reflects the annualized cost of different abatement measures in a given year per tonne of carbon saved compared with the business-as-usual technology[24]. This metric allows us to compare the economic attractiveness of different abatement measures.
- The upfront investments represent the additional capital expenditure in the year when the abatement action is taken, relative to the business-as-usual investment.

24 The abatement cost is a weighted average across sub-opportunities, regions, and years, and is calculated as the sum of incremental capital expenditures (annualized as a repayment at an interest rate of 4 percent) and incremental operational expenditures or savings.

4.1. Abatement cost

An overview of the net costs and benefits of all the technical abatement measures on the cost curve shows that some 30 percent of the measures would produce a net economic benefit and that another 50 percent would involve costs of below €20 per tCO_2e. The average cost of the abatement opportunities along our cost curve is approximately €4 per tCO_2e, making the total cost to implement the 38 $GtCO_2e$ per year on the 2030 curve approximately €150 billion per year in 2030. This is an optimistic cost estimate, both because it assumes opportunities would be addressed in perfect order according to their cost, and each would be captured to its full extent and because it excludes transaction and program costs.

The reason we have chosen to exclude transaction and program costs from our analysis is that these reflect political choices how to implement different measures and vary from case to case. Therefore, they cannot be incorporated into the cost curve in an objective way. Take the case of the abatement potential in energy-efficient light bulbs. Policy makers could either mandate the use of energy-efficient bulbs (less expensive, but intrusive) as the Australian government has chosen to do, or they could try to convince consumers to switch voluntary through education campaigns (more expensive, but less intrusive), as some European governments have opted to do. The transaction and program costs vary considerably in the two cases.

Transaction and program costs also have a high degree of inherent uncertainty, as programs of the size now being discussed have not been tried before, e.g., in Forestry. The external sources we have looked at to understand the order of magnitude of the these costs often estimate them between from below €1 per tCO_2e to €5 per tCO_2e[25], again with big variations across sectors. Using this range to illustrate the order of magnitude of the total transaction and program costs, it translates to a cost of between €40 billion per year and €200 billion per year in 2030 for the 38 $GtCO_2e$ per year of abatement opportunities we have identified. This would make the total global cost €200–350 billion annually by 2030, which corresponds to approximately 0.4 percent of the forecasted 2030 global GDP.

An alternative approach would be to value the opportunities with net economic benefits at zero, arguing, as some economists would, that transaction and program costs for these opportunities are so large that they compensate any apparent net gain. This approach makes the average cost approximately €12 per tCO_2e, and the total cost around €450 billion in 2030.

All of those cost estimates correspond to less than 1 percent of forecasted global GDP by 2030. They are optimistic in the sense that they assume that the lowest cost options are addressed first. However, they also exclude the dynamic effects of large-scale investments into new infrastructures and technologies, which many believe would have a significant positive effect on the global economy.

If temperatures increase as the IPCC estimates they will in a BAU scenario, one could compare the cost of reducing emissions (frequently called *mitigation* costs) to the so-called *adaptation* costs (i.e., the costs of managing the global warming that would occur if no or limited action was taken to reduce emissions). We have not made any attempt to quantify these adaptation costs, as they rely on a series of climate-science assumptions that are well outside our area of expertise. The IPCC estimates in their Fourth Assessment Report that these costs could be on average 1 to 5 percent of GDP for 4 degrees Celsius of warming – with high variations across the world.[26] Such estimates are uncertain by nature and controversial in the view of climate-change skeptics, who would judge adaptation costs to be much lower than these estimates, or even zero.

25 For example, Lawrence Berkeley National Laboratory; Alston and Hund; Woods Hole Research Center; Conservation Reserve Program; and the United States Department of Agriculture

26 *Climate Change 2007. Fourth IPCC Assessment Report*. Intergovernmental Panel on Climate Change

When interpreting these costs, the reader should be aware that this report assesses the costs of individual abatement levers from a societal perspective, the aim being to make our analysis of the opportunity as relevant as possible to policy makers and comparable across countries and sectors. The abatement costs that appear in the cost curve are therefore net of taxes and subsidies, and reflect a 4 percent interest rate, in line with typical long-term government bonds. This approach is different from the perspective of private decision makers who often face higher interest rates, taxes, and subsidies (see fact box "Changes in the cost curve in a decision-maker perspective").

Changes in the cost curve in a decision-maker perspective

The global cost curve takes a societal perspective, net of taxes and subsidies. This approach serves as a useful starting point for policy makers when they are prioritizing action on GHG abatement and allows for comparisons of the size and cost of abatement opportunities between countries and sectors. However, the societal approach does not reflect the economic investment case faced by those making decisions about whether to capture these opportunities. An institutional, corporate, or individual consumer will each have different interest rates, expected time horizons for repayment, and subject to taxes, tariffs, and subsidies. The cost to the decision maker is therefore often different from the cost shown in the cost curve. The decision maker perspective is better suited for assessing switching costs or estimating CO_2 prices that would be necessary to incentivize certain technology investments.

There are three broad categories of abatement levers that incur different directional cost changes from the decision maker's perspective. Levers in Buildings, Power, Industry, Forestry, and Agriculture tend to have higher costs for the decision maker mainly due to higher interest rates in these cases. Levers in Transportation energy efficiency tend to be lower from the decision maker's point of view as fuel taxes increase the value of fuel savings. Finally, some emerging technologies levers can substantially benefit from subsidies, and so we have a lower cost in a decision-maker perspective.

A large share of abatement opportunities are net profit positive

A large share of the abatement opportunities involves investing additional resources upfront in making existing or new infrastructure more carbon efficient, and then recouping part or all of that investment through lower energy spending in future years. This is the case, for example, with better insulated houses, more fuel-efficient cars, and wind power. This means that the annual abatement cost – the measure we use in our cost curve – is much smaller than the initial capital investment. In fact, if all the technical abatement opportunities at a cost of less than €60 per tCO_2e were to be implemented, we estimate the total additional investment (incremental to BAU) would be €810 billion per year in 2030. The net cost would be only about €150 billion per year.

The energy efficiency opportunities all have this financial profile, as well as many of the renewable energy opportunities. Our analysis shows that there are about 11 $GtCO_2e$ per year of abatement opportunities in 2030 – some 30 percent of all measures in the cost curve – where the energy savings actually outweigh the upfront investment, so that these opportunities carry a net economic benefit over their lifetime, even without any additional CO_2 incentive. These opportunities with a net economic benefit largely consist of energy efficiency measures in the Buildings and Transport sectors. Moreover, these opportunities have become more profitable in the past few years as a result of high energy prices.

As we highlighted earlier, some economists believe that the transaction and program costs of GHG abatement are so large that opportunities with net economic benefits cannot exist. They argue that markets are always so efficient that these opportunities would be realized or are cost positive. If there are such attractive abatement opportunities, why then have consumers and entrepreneurs not already captured them? Our view is that a range of market imperfections currently act as a barrier and disincentive and hinder some of these opportunities to fully materialize in the business-as-usual, including:

- **Lack of awareness.** In many cases, consumers and businesses are unaware of energy efficiency alternatives and the potential savings they offer. This is sometimes because individual opportunities are small, even while they yield large energy savings in aggregate. One example of this is low-energy lighting, for which there is a good business case in many countries with payback periods of only a few months, but where overall savings are often limited compared with the average household budget.
- **Agency issues[27].** In many opportunities with net economic benefits, the consumer or company reaping the benefits of lower energy bills is not actually making the upfront investment. For instance, construction companies have limited incentives to insulate homes beyond the level required in building codes, since it is to home owners and tenants that the benefits of lower energy bills accrue.
- **Financing hurdles and rapid payback requirements.** The upfront investment itself, particularly in Buildings and Transport, can be a significant barrier; many consumers require their money back in only one to two years to make energy efficiency investments. As a result, appliance makers, for instance, often compete more on shelf price than on energy consumption, and sometimes choose not to include additional energy-saving features in their products even if these pay for themselves over the lifetime of the appliance.

The fact that these opportunities offer a net economic benefit does not mean that they are easy to realize. On the contrary, designing the right policy framework to capture this potential in a cost-effective manner is a significant challenge as it requires finding ways to overcome an array of market imperfections. We discuss regulatory priorities in more detail in Chapter 7.

27 Also referred to as "split incentives"

4.2. Abatement investments

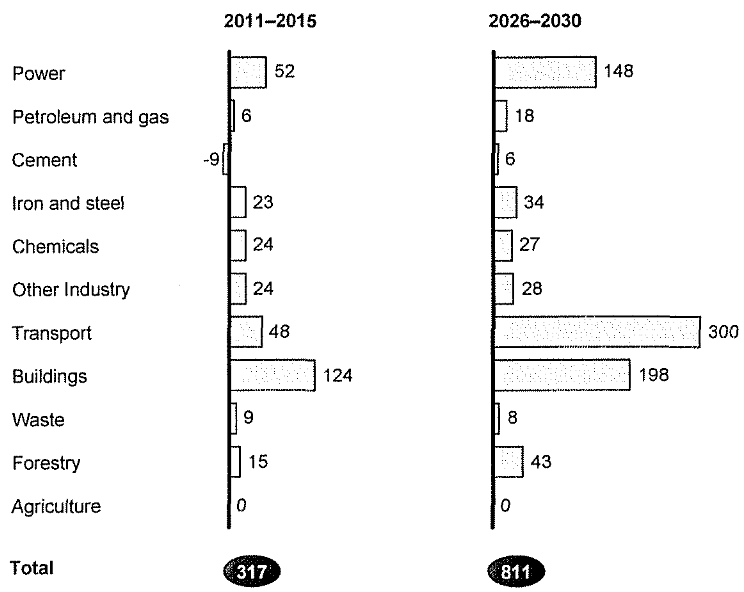
Realizing the abatement potential we have described would require global incremental investments – above and beyond BAU – of €320 billion annually in 2015, increasing to €810 billion per year by 2030. To put these capital requirements in perspective, they correspond to 5 to 6 percent of projected BAU global investments in fixed assets in each respective year. This does not appear to entail a prohibitive financing challenge at the global level. In GDP terms, the investments correspond to 1.3 percent of forecasted global GDP in 2030[28], although the actual impact of these investments on GDP would be highly dependent on how they were financed and whether regions are capital constrained.

Although the financing of abatement does not appear to be prohibitive at a global, aggregate level, there will be significant challenges in different regions and sectors. The investment needed is spread very unevenly with three sectors accounting for 80 percent of the capital required (Exhibit 4.2.1).

Exhibit 4.2.1

Capital investment by sector incremental to business-as-usual for the abatement potential identified

€ billions per year; annual value in period



Source: Global GHG Abatement Cost Curve v2 0

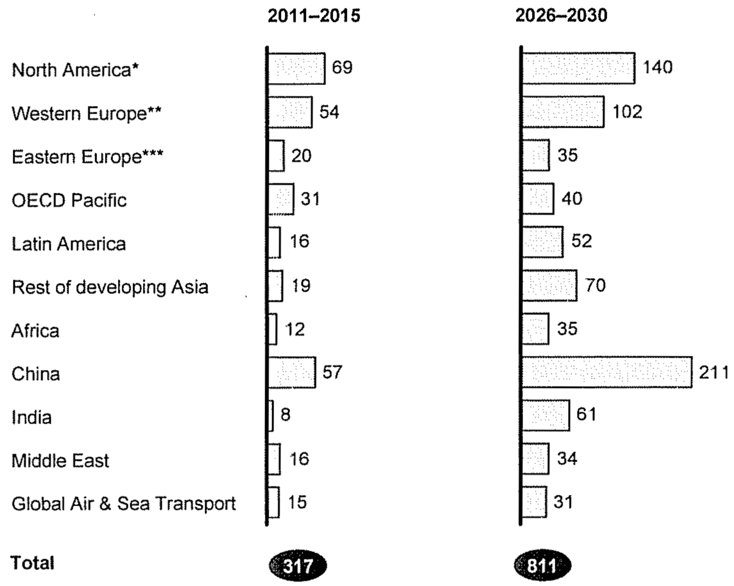
Transport and Buildings account for some 35 percent and 25 percent, respectively, of the total investment needed. These sectors are similar in that they are both consumer-driven and depend on literally billions of investment decisions. Although, investing in fuel-efficient vehicles and energy-efficient houses will often pay for itself over the lifetime of the car or house, finding effective ways to incentivize and finance the additional upfront expenditure may not be easy. A fuel-efficient car often costs between €1,000 and €3,000 more than a model that is less fuel efficient; improving the energy efficiency of a residential house between €5,000 and €10,000. New models for consumer finance will likely be necessary. The Power sector accounts for another 20 percent of the total capital required, as

28 Global GDP is projected around $90 trillion by 2030 and we use an exchange rate of 1.5 USD/EUR throughout our analysis

Exhibit 4.2.2

Capital investment by region incremental to business-as-usual for the abatement potential identified

€ billions per year; annual value in period



* United States and Canada
** Includes EU27, Andorra, Iceland, Lichtenstein, Monaco, Norway, San Marino, Switzerland
*** Russia and non-OECD Eastern Europe
Source: Global GHG Abatement Cost Curve v2 0; Houghton; IEA; UNFCCC; US EPA

most technologies here involve significantly higher upfront capital costs than today's BAU coal and gas plants. The rest of the investment required comes largely from industrial sectors.[29]

In terms of regional investment needs, three regions stand out: China with annual investment of €211 billion in 2030, North America with €140 billion per year, and Western Europe with €102 billion per year (Exhibit 4.2.2) – representing 55 percent of total global investment. In all three regions the majority of the investment is required to capture the large abatement opportunity in Buildings and Transport, which is driven by the huge asset base in these sectors. When comparing investment needs with GDP, the shares differ substantially: Whereas the investment in developed countries only represents 0.5 to 1.0 percent of GDP, in developing countries this ratio increases to 1.2 to 3.5 percent of GDP. It should be noted here again that the actual impact of these investments on GDP would be highly dependent on how they were financed and whether regions are capital constrained.

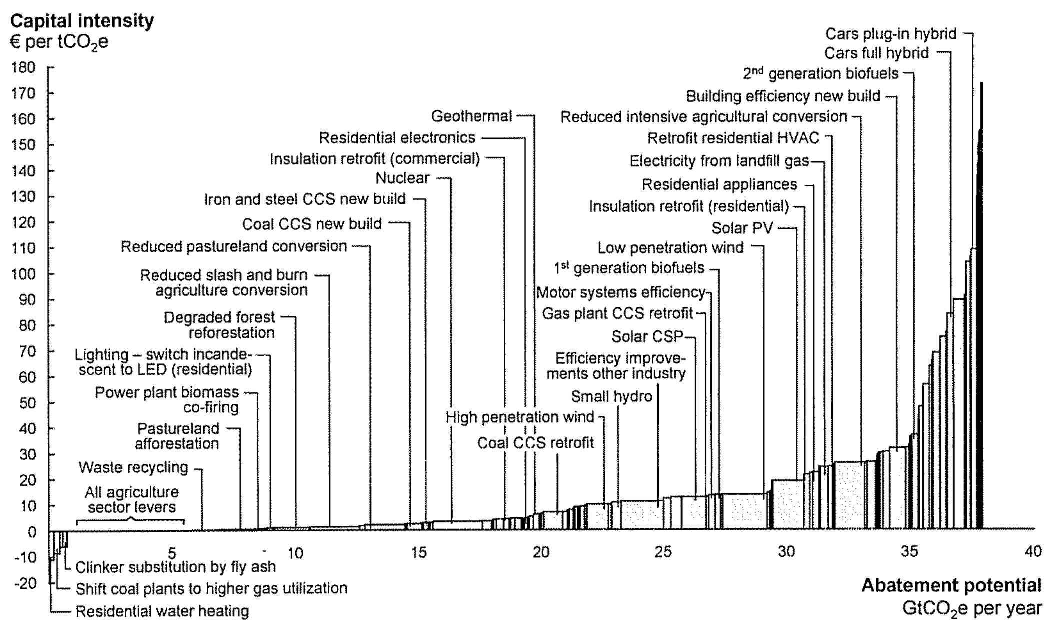
29 It is worth noting two specific features of our methodology. We assume that Forestry requires a significant amount of capital investments as all avoided deforestation measures are realized by covering the opportunity cost through an initial fund, e.g., buying the land to be protected. In cement, incremental investment compared to BAU is negative due to the fact that the substitution of clinker by other alternatives (e.g. fly ash) significantly reduces investment requirements in clinker production capacity and more than compensates for CCS and other capital investments.

Capital intensity and the prioritization of abatement action

If we turn to an analysis of the capital intensity[30] per abatement opportunity, we find that about half of the measures we have identified have a capital intensity of below €5 per tCO_2e and three-quarters of the opportunities have an intensity of below €15 per tCO_2e. It is interesting to observe that the order between opportunities in the capital curve is very different from the order in the cost curve. For instance, many energy-efficiency opportunities that appear on the left-hand side of the cost curve end up much further to the right in the capital curve (Exhibit 4.2.3)[31].

Exhibit 4.2.3

Capital intensity by abatement measure



Source: Global GHG Abatement Cost Curve v2 0

As the cost curve is the more economically rational way to prioritize abatement opportunities – taking into account not only upfront investments but also the resulting energy savings – the capital curve demonstrates that different priorities could emerge in a capital-constrained environment. Investors might choose to fund the opportunities with the lowest capital intensity rather than the lowest cost over time. This could make the cost of abatement substantially higher over time.

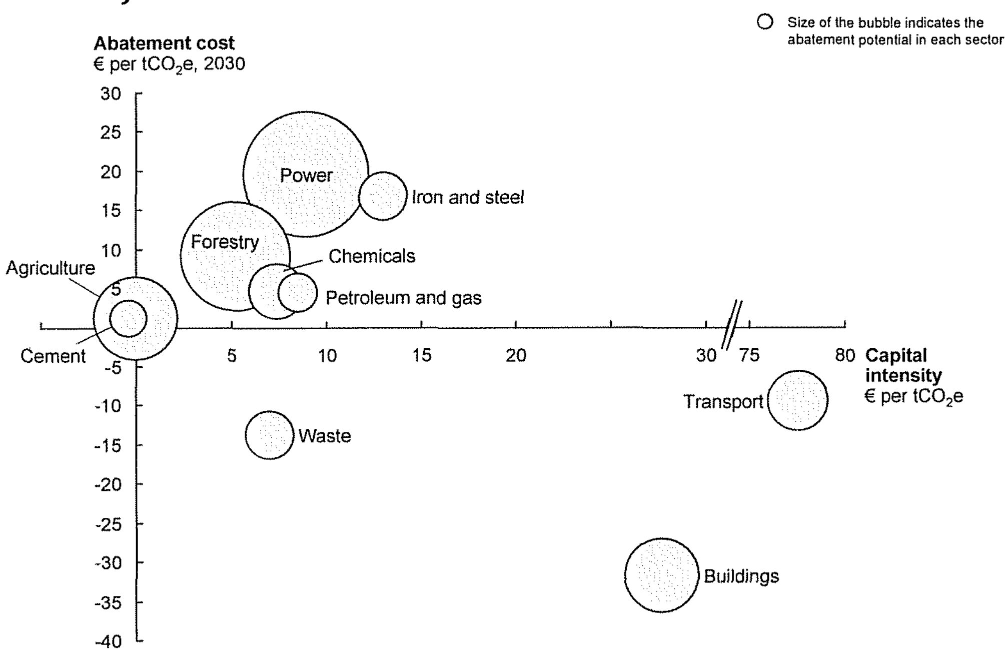
30 We define the capital intensity of an abatement measure as the additional upfront investment relative to the BAU technology, divided by the total amount of avoided emissions over the lifetime of the asset . For a more fuel efficient car, for instance. the capital intensity would be calculated as the additional upfront investment compared to the BAU technology, divided by the amount of CO_2 saved through lower fuel consumption during the lifetime of the car. The main difference with abatement cost is that the capital intensity calculation does not take financial savings through lower energy consumption into account.

31 Negative capital intensity occurs if the abatement measure requires less capital than the BAU. One example is clinker substitution in the Cement sector, where investments in new build clinker production plants would be reduced, if the share of clinker substitutes in cement is increased.

Comparing the abatement cost and abatement investments shows that the implementation and funding challenges will be very different across sectors (Exhibit 4.2.4). We can discern several groupings that share themes in common. For instance, in Transport and Buildings, upfront financing might be challenging but the cost is actually low once investments have been made. Waste is a clear win-win with both low capital intensity and attractive returns. Power has one of the higher average abatement costs but has a comparatively low capital requirement given the large amounts of emissions saved. Industrial sectors show a similar profile to Power with efficiency opportunities dampening the impact of levers such as CCS. Making the abatement happen in Power and Industry is likely more a question about compensating companies for the high costs, than it is about financing the investments. Finally in Forestry and Agriculture, both costs and investments are relatively low. Here, the implementation challenges are practical rather than economical, namely, designing effective policy and an effective way of measuring and monitoring the abatement.

Exhibit 4.2.4

Capital intensity and abatement cost



Source: Global GHG Abatement Cost Curve v2 0

5. The importance of time

5.1 The effect of delaying abatement action

If the world wants to set itself on an emissions pathway with a high probability of containing global warming below 2 degrees Celsius, taking action is urgent. The window for an effective response to climate change is relatively narrow – explicitly, the next five to ten years. The urgency of the task is not just about forgoing an opportunity to reap emissions savings in a single year or short span of years. Moreover, by not acting promptly, the world would lock itself into high-carbon infrastructure for several decades to come.

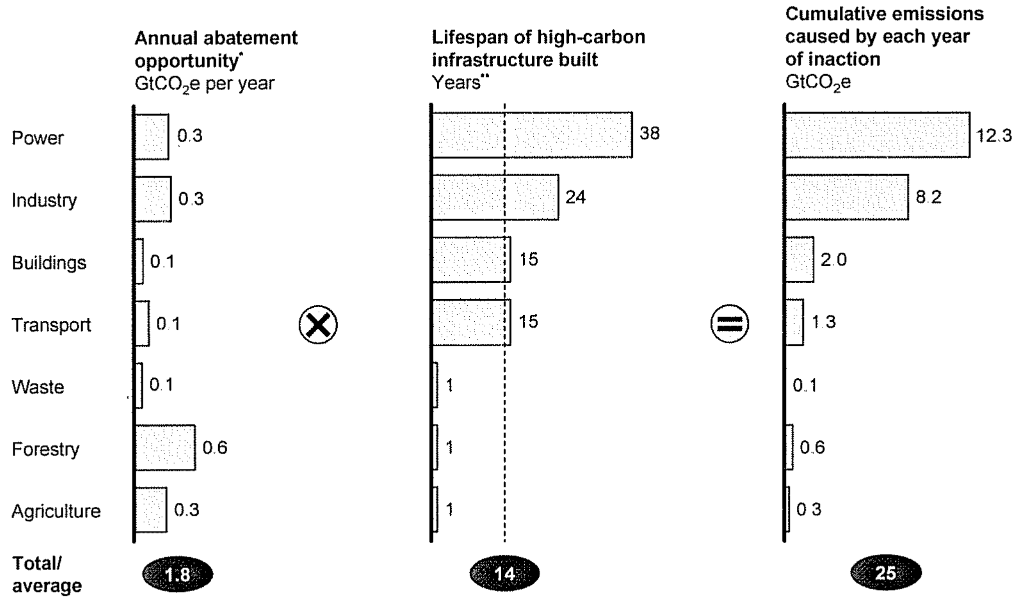
If we look at the impact of one single year of delaying abatement, we estimate that this would cause 1.8 $GtCO_2e$ of additional emissions globally in that year (Exhibit 5.1.1). The emissions would simply grow according to the BAU development instead of declining. What's more, during this year of delay, high-carbon infrastructure with long lifetimes would be built. In our assessment, the average effective lifetime of infrastructure is 14 years, but with a broad range: Coal fired power plants often have a lifespan of 40–50 years, many industrial plants of 20–30 years, and vehicles typically 10–20 years.

The result of this lock-in effect is that one year of delay – in addition to the foregone abatement opportunity of 1.8 $GtCO_2e$ in that year – commits the world to 25 $GtCO_2e$ of cumulative emissions over the following 14 years.

Turning to a delay of 10 years from 2010 to 2020, we find that there would be three major impacts. First, the potential abatement in 2030 would fall from 38 to 22 $GtCO_2e$ per year, a reduction of 40 percent. Second, such a delay would result in a cumulative lost abatement opportunity of some 280 $GtCO_2e$ by 2030 compared with action taken in 2010. This is comparable to 21 times combined 2005 US and China emissions. Finally, the lock-in effect due to a 10-year delay would continue for decades beyond 2030, especially in the case of long-lived carbon-intensive infrastructure in the Power, Industry, and Building sectors. (Exhibit 5.1.2)

Exhibit 5.1.1

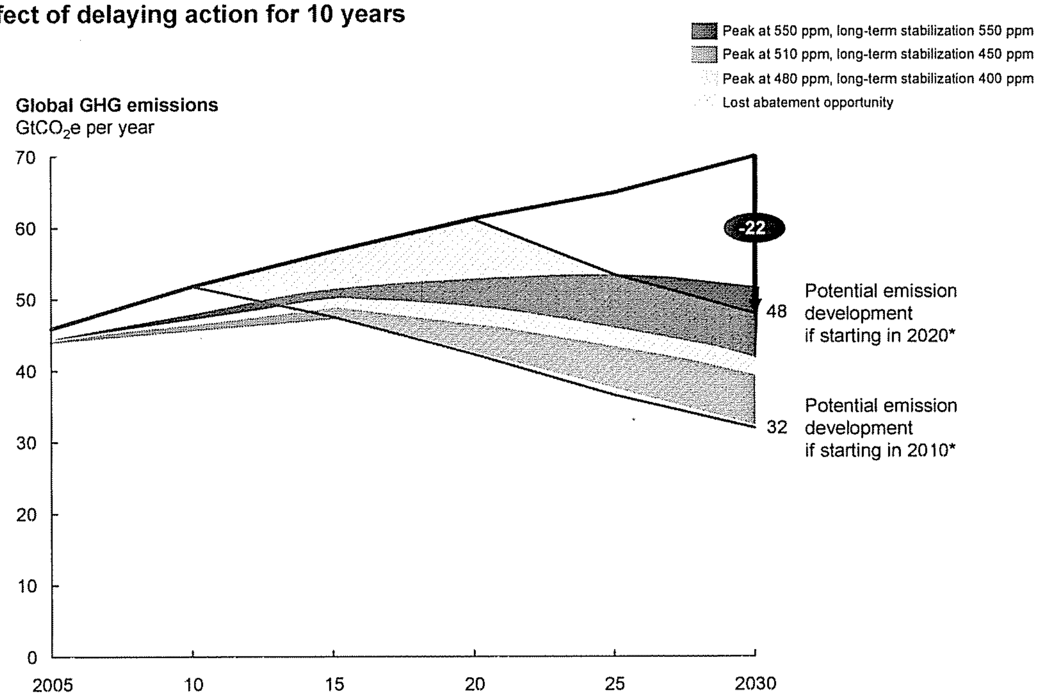
Lock-in into high-carbon infrastructure



* Annual between 2010–15; calculated as emission difference between BAU and emissions after abatement
** Weighted average of lifespan of carbon-intensive assets or infrastructures in each sector
Source: Global GHG Abatement Cost Curve v2.0

Exhibit 5.1.2

Effect of delaying action for 10 years



* Technical levers <€60/tCO_2e
Source: Global GHG Abatement Cost Curve v2.0; Houghton; IEA; OECD; EPA; den Elzen; van Vuuren, Meinshausen

In greenhouse gas concentration terms, the effect of the 10-year delay is that the atmosphere would end up a on 550 ppm emissions pathway, even if aggressive action was taken in 2020. The world would end up at the high end of the 480 ppm pathway if similarly aggressive action was taken in 2010. As a rule of thumb, one could conclude that each year of delay or inaction leads to a 5 ppm higher expected peak GHG concentration level.[32]

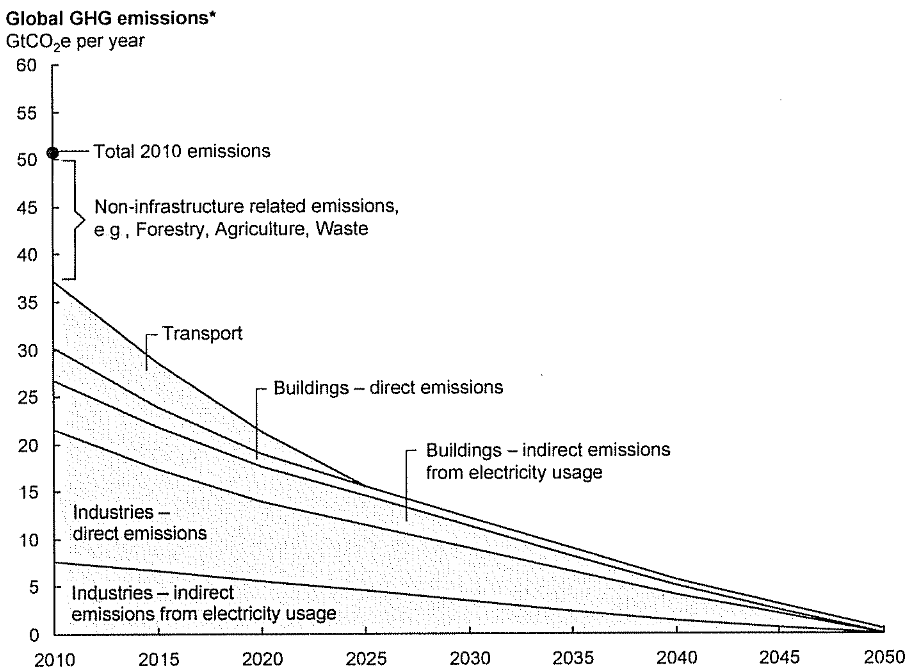
5.2 The importance of new infrastructure choices

It is critical to the effort to abate GHGs that those making infrastructure choices employ low-carbon options. About three-quarters of today's emissions are infrastructure-related, including much of the emissions from Buildings, Transportation, Power and Industrial sectors. Infrastructure is long-lived and today's capacity will only be phased out over the next 50 years, making it inevitable that the transition to a low-carbon economy will take time (Exhibit 5.2.1).

Retrofitting existing capacity – whether power plants or buildings, for instance – is far more costly than building new infrastructure with low-carbon (and energy efficient) technologies. As a result, we see that more than 50 percent of the opportunities in the cost curve relate to making the right new infrastructure choices when building new infrastructure. Only about 15 percent of the abatement potential in the cost curve comes from retrofitting existing assets to reduce their carbon intensity, with the remaining 35 percent of the curve not being infrastructure-related at all (Exhibit 5.2.2).

Exhibit 5.2.1

Existing infrastructure phase-out projection

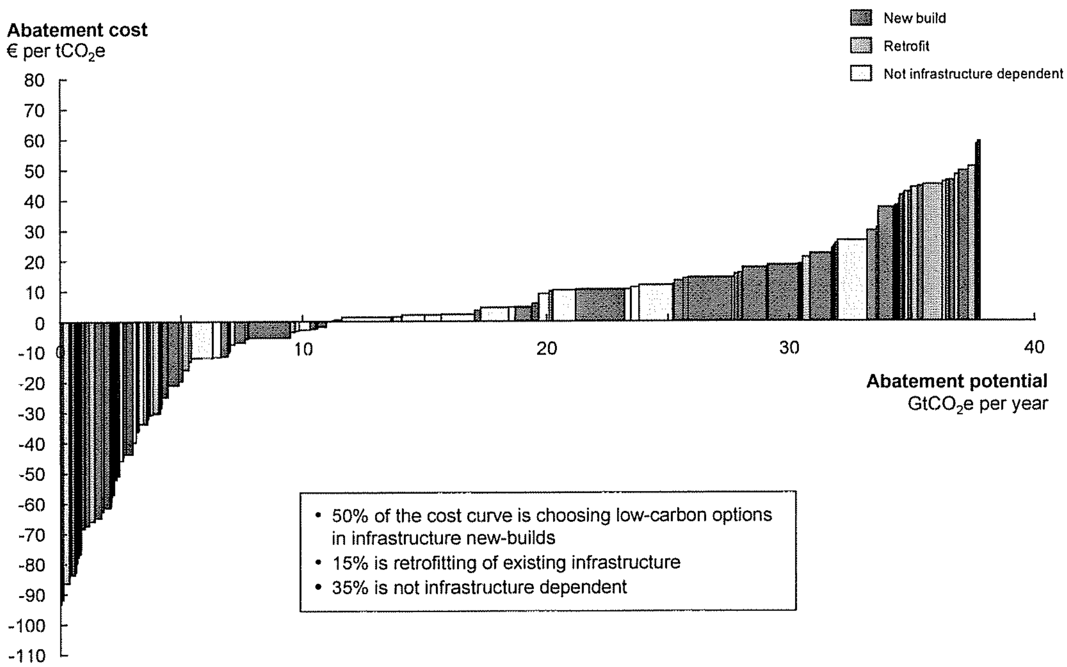


* 2005 total emissions were 46 GtCO2e.
Source: Global GHG Abatement Cost Curve v2 0

32 The effect of a 10-year delay is that 2030 emissions end up in middle of the stabilization path that peaks at 550 ppm, instead of at the high end of the path that peaks at 480 ppm. Rounding the difference to 50 ppm (to account for the fact that emissions end up in the middle of the 550 ppm scenario and the high end of the 480 ppm scenario) makes the effect 5 ppm per year.

Exhibit 5.2.2

The role of infrastructure choices along the cost curve



Source: Global GHG Abatement Cost Curve v2.0

6. Scenarios and sensitivities

6.1 Integrated implementation scenarios

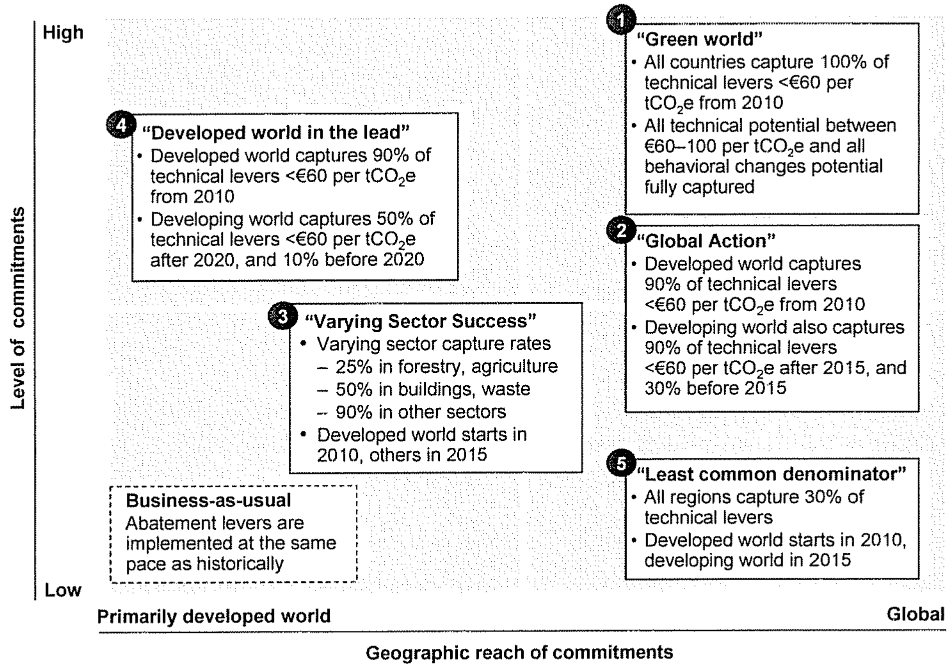
The abatement opportunities that we have outlined in this report are all potentials, i.e., they represent a best case if each opportunity is pursued to its maximum economic potential below €60/tCO_2e, and the implementation is successful globally. Some opportunities are more challenging and costly than others. In this chapter, we start to think about the effects of possible implementation leakages. We outline a set of illustrative, integrated implementation scenarios along the two dimensions of geographic reach and level of emissions reductions. These scenarios are intentionally simplified compared with the highly complex global policy discussions currently underway, since our objective is to illustrate the order-of-magnitude implications of different, conceivable global policy choices. None of the scenarios that we describe imply a recommendation about what policy is preferable.

We have developed five overall implementation scenarios (Exhibit 6.1.1). Taking these together, the overall conclusion we reach is that swift and concerted global action to reduce emissions is necessary if the world is to establish a pathway that leads to a high probability of limiting global warming to 2 degrees Celsius. If any one of the major sectors or regions do not take action, it will be very difficult for the rest of the world to make up the difference. Three out of five scenarios show substantial increases in emissions – of between 7 and 30 percent in the years between 2005 and 2030 – that would put the world on emission pathways consistent with temperature increases of 3 degrees Celsius or more (Exhibit 6.1.2).

1. **The Green World scenario** represents the most concerted global approach to reducing carbon emissions. In this scenario, all regions would start implementing their full technical abatement potential in 2010 and also opportunities to reduce emissions through behavioral changes and levers between €60 per tCO_2e and €100 per tCO_2e would be captured in all regions. Developed world emissions would be 60 percent lower in 2030 than 2005 levels while developing world emissions would be about 50 percent lower. Overall investment needs are expected to be higher than €850 billion per year by 2030, which is required to achieve full potential of technical levers below €60 per tCO_2e. This is a highly optimistic and highly challenging scenario from a implementation point of view – as it assumes all opportunities are successfully captured across regions and sectors – but it would best position the world to limit global warming to 2 degrees Celsius, as it leads to a 480 ppm peak pathway.

Exhibit 6.1.1

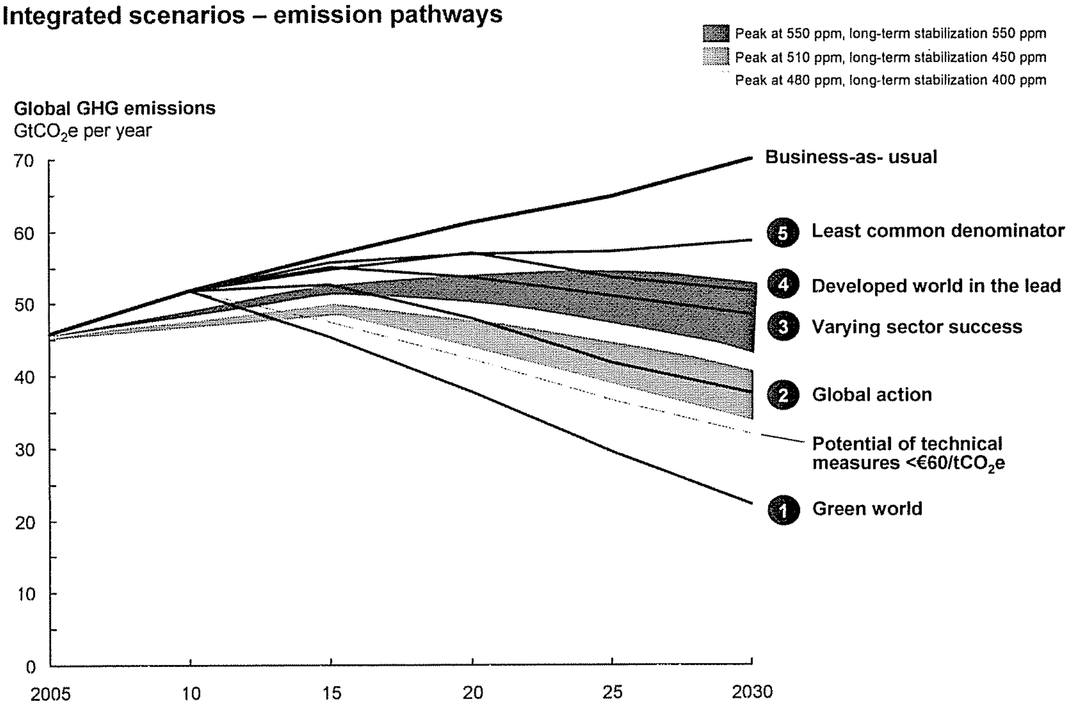
Integrated implementation scenarios 2010–2030



Source: Global GHG Abatement Cost Curve v2 0

Exhibit 6.1.2

Integrated scenarios – emission pathways



Source: Global GHG Abatement Cost Curve v2.0; Houghton; IEA; IPCC; den Elzen; Meinshausen; OECD; US EPA; van Vuuren

2. **Global action** assumes aggressive global commitment to capture the technical opportunities costing less than €60 per tCO_2e but does not assume the capture of any more expensive technical opportunities or any behavioral changes. In this scenario, the developed world captures 90 percent of the abatement potential starting in 2010, assuming a certain implementation leakage. We assume that the developing world captures 30 percent of the abatement opportunities between 2010 and 2015, largely energy-efficiency-related measures financed by, for instance, the Clean Development Mechanism. Starting 2020, the share of opportunities captured in the developing world is assumed to increase to 90 percent. In this scenario, developed world emissions would be 40 percent lower in 2030 than 2005 levels, and developing world emissions would be about 5 percent below. Overall investment needs is expected to €710 billion per year by 2030. This scenario leads to a 510 ppm peak scenario pathway.
3. **Varying sector success** assumes that, while all nations agree to tackle climate change jointly, implementation in several key sectors proves highly challenging. The developed world takes the lead, starting abatement in 2010, the rest of world soon follows suit in 2015. The success of implementation varies across sectors globally. While 90 percent of the abatement potential in Power, Transport, and Industrial sectors is achieved (sectors with a high regulatory feasibility), only 50 percent of the opportunities in Buildings and Waste are realized. The Forestry and Agriculture sectors – where effective regulations are notoriously challenging to put in place – see an even lower adoption rate of 25 percent. In this scenario, the developed world would reduce 2030 emissions to 30 percent below the 2005 level, but emissions in developing regions would be some 30 percent above the 2005 level. Overall investment needs is expected to €590 billion per year by 2030. This scenario would leave the world on a 550 ppm peak pathway.
4. **Developed world in the lead** assumes that the developed world implements 90 percent of the technical opportunities from 2010. The developing world would achieve only 10 percent of their abatement potential between 2010 and 2020, and then implement 50 percent of their potential between 2020 and 2030. Developed world emissions would be some 40 percent below the 2005 level while developing country emissions would increase by about 50 percent from 2005 to 2030. Overall investment needs is expected to €440 billion per year by 2030. This scenario would also leave the world on a 550 ppm peak pathway.
5. **Least common denominator** assumes that all nations agreed to participate in a coordinated global regulatory framework, but that abatement targets are set at comparatively low reduction levels. This scenario assumes that the developed world takes action in 2010 and the developing world in 2015. All regions achieve only 30 percent of their abatement potential. Developed world emissions in 2030 would be at the same level as in 2005, while emissions in developing countries would be about 50 percent above 2005 levels. Globally, this scenario would lead to emissions being about 30 percent above 2005 levels in 2030. Overall investment needs is expected to €250 billion per year by 2030. This scenario would lead to a pathway above the 550 ppm pathway scenario.

The five scenarios that we have outlined demonstrate that to meet or stay below the 2 degrees Celsius global warming level, concerted action across regions and sectors is required.

6.2. Uncertainties and sensitivities

There are, as we have stressed, significant uncertainties both about the impact of different abatement opportunities and their cost. This is unavoidable in any investigation with such a broad scope and long time horizon, and means that our abatement data should be interpreted as directional estimates rather than exact quantifications.

Assumptions of the volume or impact of abatement opportunities in different sectors are highly sensitive to implementation success "on the ground". Agriculture and Forestry could technically provide up to 12 $GtCO_2e$ per year of abatement, but implementation of the abatement measures we include in the cost curve has never been attempted on such a large scale. The same is true for most of the energy efficiency measures we have identified. On the other hand, there could also be technological breakthroughs that could deliver unanticipated abatement potential.

Estimates about the cost of abatement and its investment requirements is highly sensitive to what assumptions we make about energy prices, the rate of future technology developments, and interest rates. We have discussed sensitivities with relation to abatement volumes in the previous section and therefore focus on costs in the following section.

Abatement economics sensitivity to energy prices

The past year has shown that energy prices can be subject to extreme volatility, with oil prices fluctuating between about $150 and $50 a barrel in the span of less than six months. One perennial question raised in the climate-change debate is whether high energy prices in themselves are not enough to cut emissions. Our study suggests that high energy prices help – but are not enough per se to deliver sufficient reductions in emissions.

It is true that an increase in energy prices reduces the average cost of abatement by making energy efficiency opportunities more profitable and the switch to alternative energy sources cheaper. If we assume an average oil price of $120 per barrel rather than the $60 a barrel price assumed by the IEA in the BAU forecast we use, and that other energy prices increase proportionally, this reduces the average cost of abatement in our model by approximately €19 per tCO_2e, equivalent to cutting the total cost of abatement in 2030 by approximately €700 billion annually. As a very rough rule of thumb, increasing oil prices by $10 (€6.7) per barrel cuts average abatement costs by €3 per tCO_2e within the $60–120 per barrel range (Exhibit 6.2.1).[33] In contrast, a low energy-price environment with an oil price of $40 (€27) per barrel results in an increase of average abatement costs of about €4.5. However, increasing energy prices is not a cheap way to reduce emissions, as the energy-price increase would create a wealth transfer from oil users to oil suppliers that is several times higher than the savings in emissions abatement cost.

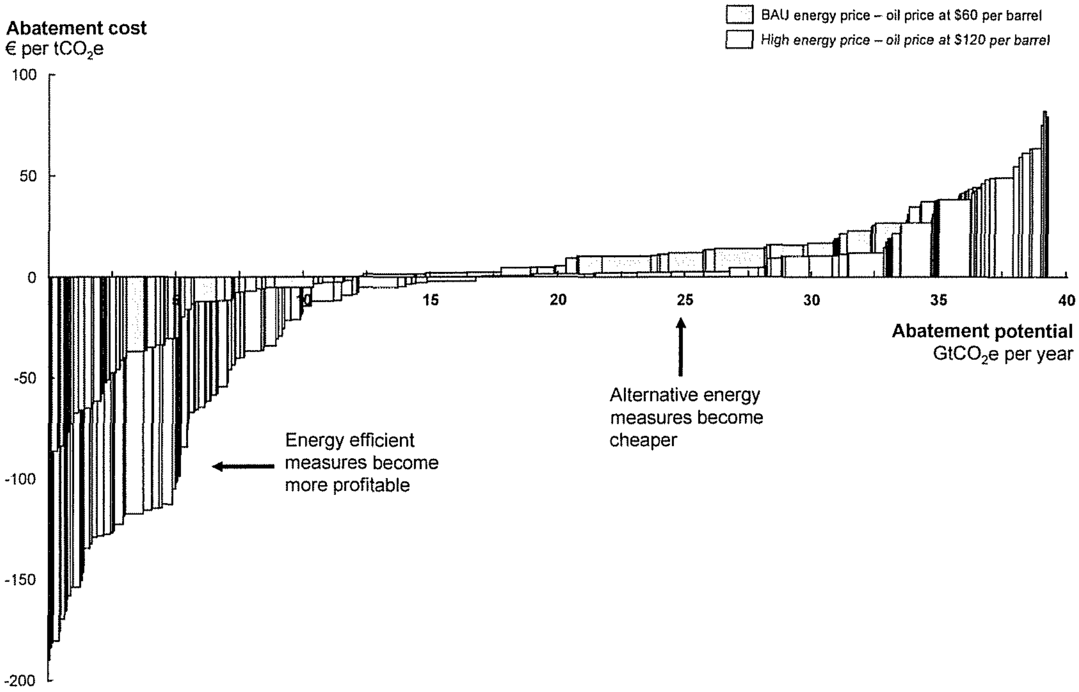
There is another important effect of high energy prices, one that our model does not capture – the impact of high energy prices on energy consumption. However, in a recent study, the McKinsey Global Institute has estimated that an increase in the oil price from $50 a barrel to $70 a barrel would cut global 2020 energy demand by as little as 1.1 percent, everything else equal. There are two reasons for this limited effect. First, oil-price changes only have an impact on a small proportion of the range of energy prices paid by end users, due to regulated, subsidized, or heavily taxed end-user prices. Second, high oil prices accelerate GDP growth and therefore energy demand in oil-exporting countries, where oil tends to be subsidized and energy productivity is low.[34]

33 Other energy prices increase according to the historic pattern of price correlations between oil, gas, and coal.

34 *Curbing global energy demand growth: The energy productivity opportunity*, McKinsey Global Institute, May 2007 (www.mckinsey.com/mgi)

Exhibit 6.2.1

Effect of high energy prices (oil price at $120 a barrel)



Source: Global GHG Abatement Cost Curve v2 0

Uncertainty of future technological development

There is also uncertainty around the future rate of technology improvement, especially for emerging technologies with high expected learning rates. However, even if costs do not decline as rapidly as we assume, the overall effect on the average cost and volume of abatement remains moderate. In the unlikely case of a significant shortfall in learning rates for multiple technologies (we modeled a case in which the learning rates of several key emerging technologies[35] would be only two-thirds of what is assumed in our standard assumptions), average abatement costs increase by less than €3 per tCO_2e, and the volume of abatement remains almost constant. While implementation of the affected individual technologies would change significantly, other low-carbon technologies can in many cases partly compensate.

As an example, we have assessed the effect of changing the learning rate[36] of solar PV from 18 to 14 percent. For the base learning rate of 18 percent, power generation costs go down from €180 per MWh in 2005 to €36 per MWh in 2030. With the lower learning rate the costs would only decrease to €53 per MWh and the 2030 abatement cost would increase by €20 per tCO_2e. In addition, this has an impact on abatement potential due to merit order effects, which decreases by more than 15 percent. However, the overall results for the Power sector only change slightly because other low-carbon technologies such as wind, biomass and CCS could partly compensate for the lost abatement volume. One exception is the CCS technology. It has a total potential of 3.3–4.1 $GtCO_2e$ per year in 2030. If it

35 Solar PV, Solar CSP, Geothermal, Nuclear, CCS, LEDs, Solar water heaters, Hybrid vehicles

36 Defined as the cost decrease for every doubling of cumulative installed capacity

would not materialize as expected, it would be hard to compensate for, as it is the only technology that can on a large scale address the emissions from existing fossil fuel power plants and respective point source emissions in the industry.

Capital-intense abatement opportunities are sensitive to interest-rate levels

Our BAU assumes an interest rate of 4 percent, similar to long-term government bond rates. This is because we take a government/societal perspective on the cost of abatement, the idea being that, if a government wanted to incentivize a capital-intense abatement opportunity, it could borrow at the bond rate to do so. Increasing the interest rate boosts capital costs and therefore increases the total cost of abatement. A higher interest rate reflects more closely the situation that decision makers face when making investments, for example based on their company's weighted average cost of capital. Setting the interest rate at 10 percent instead of 4 percent increases the overall cost of abatement from €4 per tCO_2e to about €14 per tCO_2e; with an interest rate at 15 percent, the abatement cost rises to €21 per tCO_2e. As a rough rule of thumb, average abatement costs increase by approximately €7 per tCO_2e for every 5 percentage points increase in the interest rate. Capital-expenditure-intensive abatement measures such as nuclear, solar, and wind see even higher cost increases.

7. Four areas of regulation

Effective policy and regulation will be at the core of the response to global warming. In fact, the transition to a low-carbon economy might be the first global economic transition of this scale to be driven largely by policy. Designing this policy is a huge challenge to political leaders and regulators: it needs to achieve aggressive emission reductions, incorporate many sectors of the economy, be acceptable by many countries, be cost effective, and be equitable among the many stakeholder groups that are concerned.

This study does not take a view of what regulation should be put in place and how aggressively targets should be set. These are political decisions, that need to be made considering all the aspects above, and also considering many non-climate related political priorities. However, our research highlights four categories of abatement opportunities that policy makers should consider to achieve emission reductions at lowest possible cost (Exhibit 7.0.1):

1. **Regulation to overcome the market imperfections that prevent the net-profit-positive opportunities from materializing, e.g. through technical norms and standards.** As described above, there are significant abatement opportunities that already today offer net economic benefits, but still do not materialize due to agency issues and other market imperfections. These opportunities very often relate to energy efficiency, and are largely concentrated in the Buildings, Transport and Industry sectors. To realize them, policy makers need to find a way to overcome the market imperfections, i.e., to align the interests of the large numbers of consumers and companies that need to be involved in making these opportunities come true. This is no easy task, as this type of regulation is often politically sensitive, and often has unwanted side effects such as competitive distortions. Technical standards and norms is one often-used policy instrument, but there are also others.

2. **Establishing stable long-term incentives to encourage power producers and industrial companies to develop and deploy GHG-efficient technologies.** The policy implementation challenges are comparatively limited in these sectors: emissions come from a relatively small number of large point sources that are easy to measure and monitor, companies in these sectors are typically used to making financial decisions based on regulatory incentives, and consumer implications are comparatively small. At the same time, there is a cost attached to most of the abatement action in these sectors. To realize the abatement opportunities, therefore, policy makers need to establish some type of financial incentive to make it attractive for companies to invest in abatement, e.g., in the form of a CO_2 price or a CO_2 tax.

3. **Providing sufficient incentives and support to improve the cost efficiency of promising emerging technologies.** There are many innovative technical solutions that are promising in terms of having

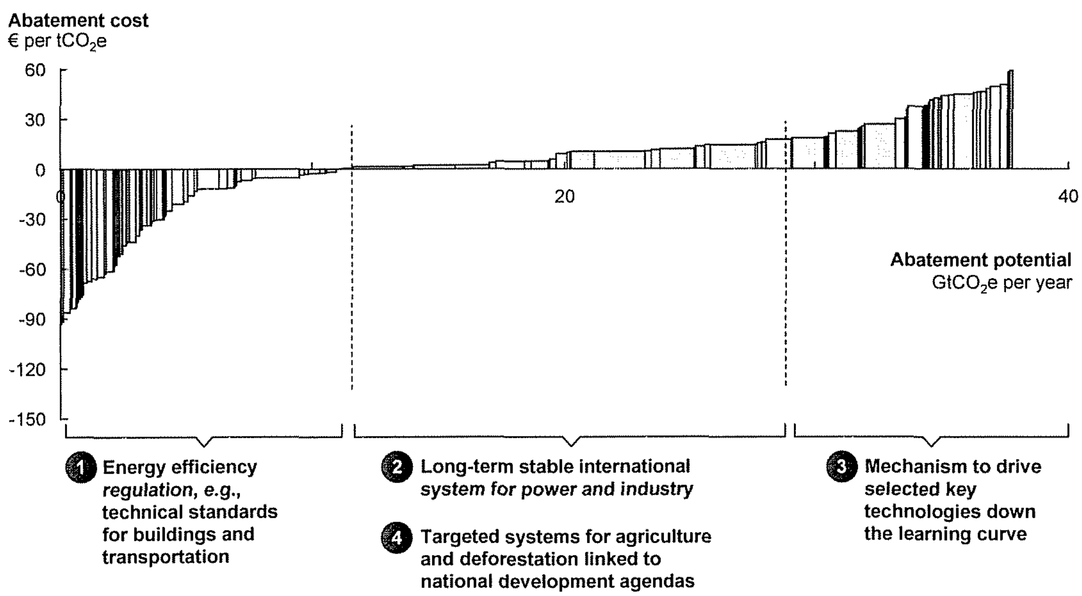
a global impact on reducing emissions in the long term, especially in period between 2030 and 2050. However, these evolving technologies are today too expensive to encourage their development through a carbon price alone. To bring these technologies into play, policy makers need to provide targeted financial support already now so that they can travel down the learning curve and provide low cost abatement solutions in the future.

4. **Addressing the potential in Forestry and Agriculture, primarily located in developing economies, linking abatement to overall development.** It is notoriously difficult to achieve emission reductions in these sectors: the emissions are concentrated in the developing world, they are very disperse among billions of people, they are difficult to measure and monitor, and they are tightly linked to other local development issues such as land ownership. To address these emissions, policy makers will need to design effective local policies that change the work practices of literally hundreds of millions small farmers and forest workers, and that fit within the context of the overall development agenda of the concerned regions. The success of such abatement policies and programs remains highly uncertain, as they have not been tried on this scale before.

Achieving effective regulation in the four above-mentioned areas presents a significant challenge, but also a great opportunity for policy makers to achieving emissions reductions at lowest possible cost.

Exhibit 7.0.1

Key areas of regulation



Source: *Global GHG Abatement Cost Curve v2 0*

8. Sectoral abatement opportunities

8.1 Power

The Power industry plays a unique role in climate change, being by far the largest sector both in emissions and opportunities to reduce them. In 2005, power industry emissions were 10.9 $GtCO_2e$ per year, or 24 percent of global GHG emissions. In a BAU projection, emissions are expected to grow to 18.7 $GtCO_2e$ per year in 2030, which would keep the Power sector's share of global emissions approximately constant. This development is driven by a doubling in global electricity demand and by a preference for fossil-based electricity production in many parts of the world. However, there are also many opportunities to reduce emissions. These options fall into four broad categories: renewable energy, CCS, nuclear energy, and demand reductions through energy efficiency. Adding up the potential of these four groups, there is a total emissions reduction opportunity of 12.4 $GtCO_2e$ to 14.4 $GtCO_2e$ per year in 2030. If the full potential were to be captured, power emissions in 2030 would be reduced to 40 to 60 percent below 2005 levels, and there would be a major shift of the global production mix towards low-carbon alternatives. The implementation challenges in the Power sector are largely related to technology: making renewable energy technologies, CCS and nuclear more cost competitive, and increasing their capacity. The fact that so many of the abatement opportunities rely on emerging technologies makes future cost estimates uncertain.

Business-as-usual emissions

In the BAU case – based on the IEA's *World Energy Outlook 2007* – global power demand grows by 94 percent from 2005 to 2030.[37] The IEA assumes global growth in power generation of 2.7 percent per year, which is closely in line with GDP growth. In developed countries, power demand increases slightly more slowly than GDP; in developing moderately faster than GDP since energy demand increases proportionally more quickly when a country is industrializing. Geographically, North America and China together account for over 40 percent of 2030 power demand. The rest of Asia

37 The BAU development reflects the IEA's view of power generation capacity growth if the policy environment remains as it is today. Our research studies abatement opportunities on top of and relative to this BAU case.

and Western Europe make up another 20 and 14 percent, respectively, of 2030 demand. The BAU case assumes slightly decreasing carbon intensity driven by more efficient plants and by a slight production mix shift towards lower carbon options, resulting in an emissions increase by 72 percent between 2005 and 2030, from 10.9 $GtCO_2e$ to 18.7 $GtCO_2e$ per year. The emissions growth stems primarily from a forecasted continued growth in coal-fired power generation, from approximately 9,450 TWh in 2005, to 16,000 TWh 2030, but also from growth in gas-fired generation (from 5,700 TWh in 2005 to 8,800 TWh in 2030).

Potential abatement

Emissions abatement in the Power sector is achieved by reducing demand for electricity, or by replacing fossil-fuel power generation with low-carbon alternatives. (see "Abatement methodology in the power model"). To achieve this, there are four key groups of abatement measures (see also Appendix IV for detailed assumptions):

- **Energy efficiency.** Energy efficiency improvements made in electricity-consuming sectors reduces the demand for electricity production compared to the BAU case, which contributes to emission reductions. According to our model, the 2.7 percent annual growth of electricity demand in the BAU would be reduced to 1.5 percent per year if all electricity saving measures were realized in electricity consuming sectors. This efficiency effect is slightly reduced by additional electricity demand for CCS in the industry sectors and electrified vehicles. The total net emissions savings from this is approximately 4.4 $GtCO_2e$ per year in 2030.
- **Renewable energy.** There are many promising renewable energy technologies. The key technologies providing abatement in our model are wind, solar photovoltaics (PV), concentrated solar power (CSP), geothermal, biomass, and hydro. Other renewable power generation technologies, such as wave and tidal power generation, also have potential for emissions abatement, but most researchers agree that these will not contribute significantly to electricity production by 2030.
- **Nuclear energy.** We estimate that the total amount of nuclear power produced could almost double from 2005 to 2030, from ~2,700 TWh to ~4,900 TWh. The reasons why not even more nuclear capacity could be built in a 2030 time frame are the long lead times in nuclear construction, and all the supply chain constraints that the industry will run into when scaling up their installations. These estimates are in line with the volumes the World Nuclear Association assumes in an aggressive build-out scenario.
- **Carbon Capture and Storage (CCS).** Our modeling assumes that this technology – at the demonstration stage today – will prove feasible at a large scale, and will come down to a cost of €30 to €45 per tCO_2e in a 2030 perspective. As such, we estimate that it could have a significant emissions impact – as it is the only currently feasible technology that allows for continued use of coal for power generation, while at the same time reducing emissions substantially. CCS can also be used to address the emissions from large point sources in Iron and Steel, Chemicals, Cement, and Petroleum. We estimate that the combined potential for CCS across Power and these Industry sectors is up to 3.3–4.1 $GtCO_2e$ per year by 2030.

Estimating the impact that each low-carbon technology could have and how its costs could develop is a highly complex topic that depends on the learning rates of different technologies, the development of fuel prices, natural limitations (e.g., average insolation intensity), demand patterns over time, the setup and capacity of the power grid, and many other factors. Our abatement model does not try to capture the

Abatement methodology in the power model

The abatement calculations in the power sector were conducted in four stages:

1. For each geographic region in our scope, the aggregated electricity demand from the electricity-using sectors was determined, starting from the IEA's WEO 2007 business-as-usual forecasts, but adjusting for electricity demand reductions from energy efficiency measures, as well as increases; e.g., from electrification of transport.
2. The need to build new electricity production capacity in each geographic region was determined, based on the electricity demand forecast, as well as a simulation of retirements in the existing power plant fleet.
3. Low carbon technologies were ordered in terms of cost competitiveness in each region, using lowest 2030 cost as the criteria, and taking best available information of future learning rates and fuel prices into account. The maximum available volume of each low-carbon technology was also determined, using the assumptions and constraints laid out in "Table A: Key technology assumptions".
4. Each low carbon technology was in the model built out to its maximum potential, in order of increasing cost, until the electricity production capacity gap was filled.

full complexity of power markets, nor does it try to forecast how the power generation mix will develop. Instead, the model examines the *potential* to reduce GHG emissions in the Power sector (assuming required policy is put in place), and it provides estimates of what role different technologies could play and what their cost could be in a global stretch scenario where the ambition would be to reduce emissions to the maximum extent possible.

To illustrate the uncertainty in the impact of different technologies, we have developed two scenarios for the Power sector (Exhibit 8.1.1). Note that these scenarios are not actual development forecasts for 2030 but reflect what is possible if all available options are captured:

E. **Maximum growth of renewable and nuclear energy.** This scenario assumes that each low-carbon technology is built out to its maximum estimated potential in each geographic market by 2030 (see Appendix IV for the estimates on each technology). The potential per technology depends on its relative cost competitiveness, and on the need for new power generation capacity in each country in each time period up to 2030. This scenario results in a major change in the mix of new capacity built compared to the BAU case and major changes in the overall 2030 power mix. This is the scenario used in the global cost curve, aggregated across all sectors.

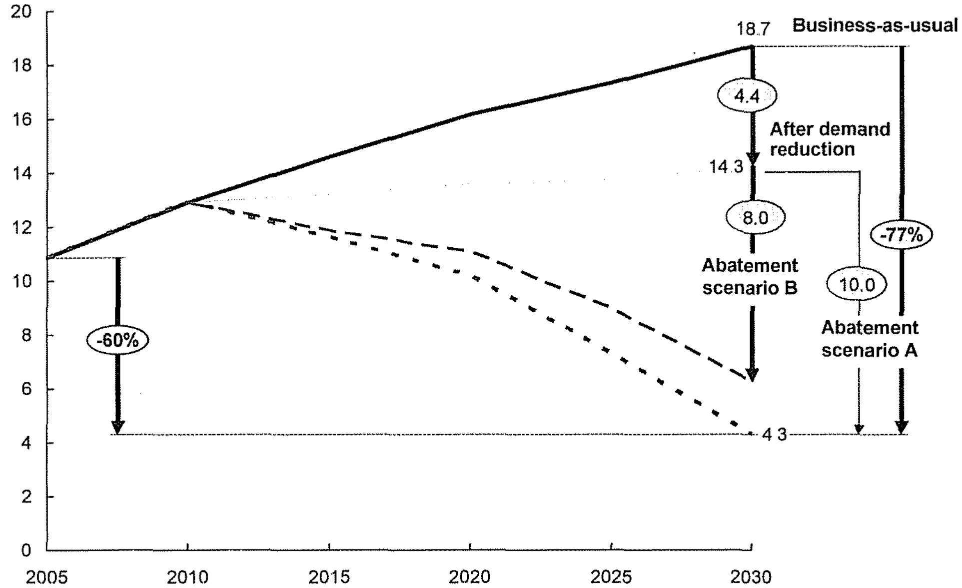
F. **50 percent growth of renewable and nuclear energy.** This scenario recognizes that while the growth rates for each low-carbon technology in Scenario A is realistic, the total scale of change for the Power sector under Scenario A is massive and that, even if there were to be aggressive global policy action in support of reducing emissions, it is not unlikely that one or more technologies would fall short of the estimated potential. To illustrate what such challenges could mean for the sector, we have constructed a Scenario B that limits the growth rate of key renewable technologies (wind, solar PV, solar CSP, biomass) and nuclear energy to 50 percent of the potential in Scenario A. Instead, more fossil-fuel-based power generation capacity is built under this scenario, some of it equipped with CCS.

Interestingly, both scenarios result in broadly similar emissions levels and cost levels in 2030. This is because there are so many low-carbon technologies that in a 2030 time horizon look likely to have an abatement cost below our threshold of €60 per tCO_2e, and their combined potential outweighs the need for new power generation capacity. In fact, it is in Scenario A the pace at which existing fossil fuel plants need to be replaced that limits the abatement potential. The result is that if one or a few technologies fall short

Exhibit 8.1.1

Emissions development for the Power sector – Scenarios A (maximum renewables/nuclear) and B (50 percent renewables/nuclear)

$GtCO_2e$ per year



* Economic potential of technical measures

Note: This is an estimate of maximum economic potential of technical levers below € 60 per tCO_2e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play

Source: Global GHG Abatement Cost Curve v2.0

of their potential, other technologies can largely make up for the loss in abatement. For example, the higher number of fossil-fuel plants built under Scenario B would increase the opportunity for CCS by more than 35 percent and largely compensate for the abatement losses from renewable and nuclear energy.

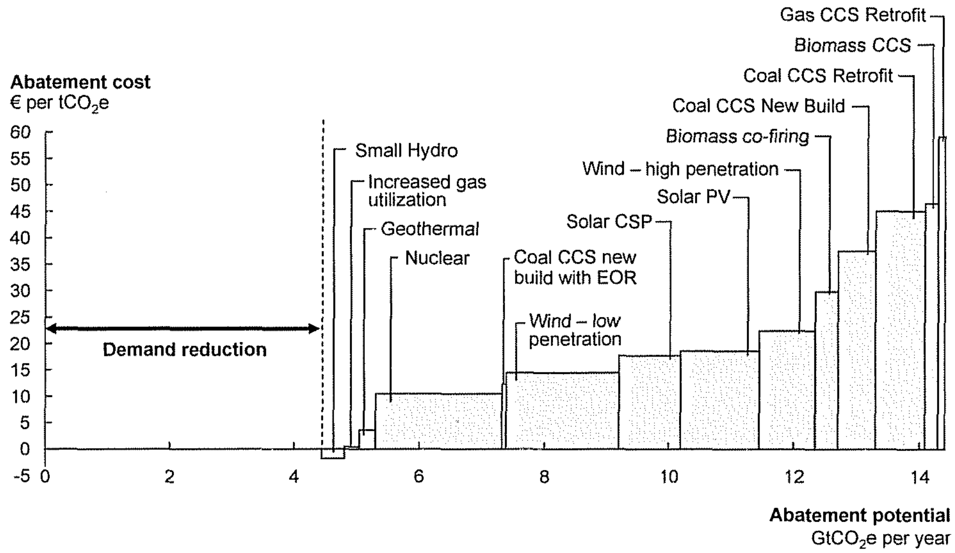
Scenario A: Maximum growth of renewable and nuclear energy. With an overall abatement potential of 14.4 $GtCO_2e$ per year in 2030, including demand reductions of 4.4 $GtCO_2e$ per year from other sectors (due to energy efficiency), this scenario results in 2030 emissions that are about 60 percent below the 2005 level. Renewable sources of power form the largest share of the abatement potential, with more than 6 $GtCO_2e$, or about 60 percent of the overall potential within the Power sector. CCS levers combine to produce emissions abatement of around 1.8 $GtCO_2e$ per year, while nuclear energy accounts for roughly 2.0 $GtCO_2e$ per year of the potential. The cost curve for this scenario shows that several low carbon technologies have a similar abatement cost by 2030 (Exhibit 8.1.2). This reflects the high level of uncertainty about which technologies are likely to prove to be "winners." Geographically, the largest abatement potential in this scenario comes from China, the United States, and India, adding up to over 65 percent of the total potential – slightly more then these countries' share of emissions, which is about 60 percent. In our modeling, we have taken into account that there are long construction lead-times for power plants, in particular for coal, hydro and nuclear plants. Due to this, the abatement potential that we have modeled in the 2010–2015 period is significantly lower than it would otherwise have been.

In Scenario A, the power-production mix in 2030 is in stark contrast to the BAU case, showing a drastic shift toward cleaner generation methods (Exhibit 8.1.3). Whereas in the BAU case about 70 percent of electricity comes from fossil-fuel plants in 2030, only about 35 percent does so in the Scenario A abatement case. This reduction is mainly driven by the significant replacement of to-be-built fossil fuel plants by renewables and nuclear in high-growth countries such as China. On a global level, renewables (including large hydro) and nuclear energy account for about 65 percent of the power mix. While this may

Exhibit 8.1.2

Global GHG abatement cost curve for the Power sector – Scenario A: Maximum growth of renewables and nuclear energy

Societal perspective; 2030

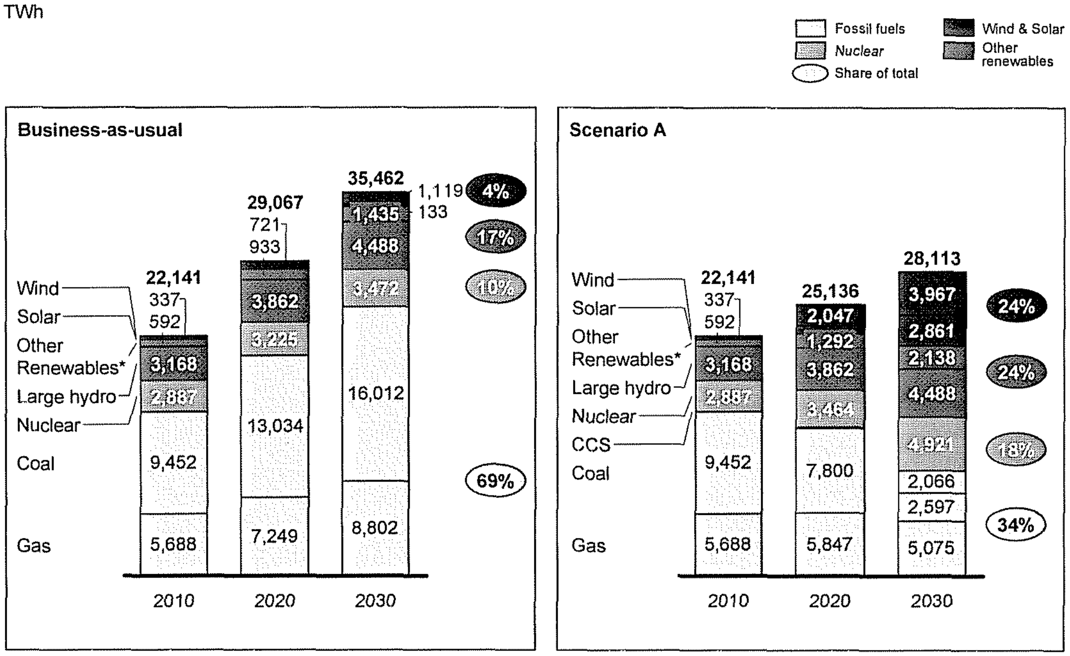


Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €60 per tCO_2e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play.
Source: Global GHG Abatement Cost Curve v2.0

Exhibit 8.1.3

Production mix – Scenario A: Maximum growth of renewables and nuclear energy

TWh



* Small hydro, geothermal and biomass
Source: Global GHG Abatement Cost Curve v2.0

seem a very high proportion, the share of intermittent power sources (i.e., wind and solar PV) has in our model been capped at 20 percent of the power production in any individual country[38]. This 2030 power production mix would make the CO_2 intensity of the Power sector decrease from around 600 tCO_2e per GWh in 2005 in the BAU to about 170 tCO_2e per GWh in 2030.

The average abatement cost in this scenario – if all the levers in the Power sector are implemented[39] – is about €20 per tCO_2e, and the total investments in power generation – in addition to the BAU investment levels – would be approximately €50 billion per year in 2015, and approximately €150 billion per year in 2030. This makes the Power sector, together with Buildings and Transport, the sectors that see the *highest need for additional investment to reach their full abatement potential*. The average abatement cost is highly sensitive to the cost of fossil fuels; the higher the cost of fossil fuels, the lower the relative cost of replacing them with low-carbon alternatives. In a high fossil fuel price scenario, which assumes oil at $120 per barrel (€80 per barrel) and other fossil fuel prices changing proportionally[40], the average abatement cost would decrease from €20 to €9 per tCO_2e, and vice versa in a low fossil fuel price scenario.

Socioeconomic view	**Average cost** (€ per tCO_2e)	**CapEx** (€ billion per year)	**OpEx** (€ billion per year)
2015	20	52	3
2020	17	96	1
2025	18	147	-7
2030	20	148	-2

Abatement action in the Power sector is also very sensitive to time. Delaying abatement action for ten years, for example, would decrease the abatement potential to 5.2 $GtCO_2e$ per year by 2030, a reduction of almost 50 percent compared to if abatement action would start already in 2010. What is more, this delay would lock in emissions from new-build fossil-fuel plants that would likely last beyond 2050, as the lifetime of a coal plant is often more than 40 years. The delay would also postpone the learning effects of emerging low-carbon technologies and make them more expensive in a 2030 time horizon.

Scenario B: 50 percent growth of renewable and nuclear energy. By significantly limiting the growth of renewable energy and nuclear relative to Scenario A – to reflect the huge challenge of the sector to shift around the investment mix so fast – this scenario sees more fossil capacity being built, some of it equipped with CCS technology. The total abatement potential is around 12.4 $GtCO_2e$ per year (including the same demand reduction) in 2030 at an average cost of some €21 per tCO_2e. Interestingly, this abatement potential is only 2 $GtCO_2e$ lower than in Scenario, and the average cost is only about €1 per tCO_2e higher. The merit order of the levers on the cost curve remains similar (Exhibit 8.1.4), but the potential of renewable energy and nuclear decrease and, depending on their respective learning rates, they also increase in costs. The loss in abatement potential is partly compensated by an increase in CCS potential of around 0.7 $GtCO_2e$ per year.

In Scenario B, intermittent power sources reach roughly 16 percent of the 2030 power mix, while fossil fuels (including CCS levers) account for nearly half of total power production (Exhibit 8.1.5).

Implementation challenges

38 Some countries such as Denmark already approach similar levels.

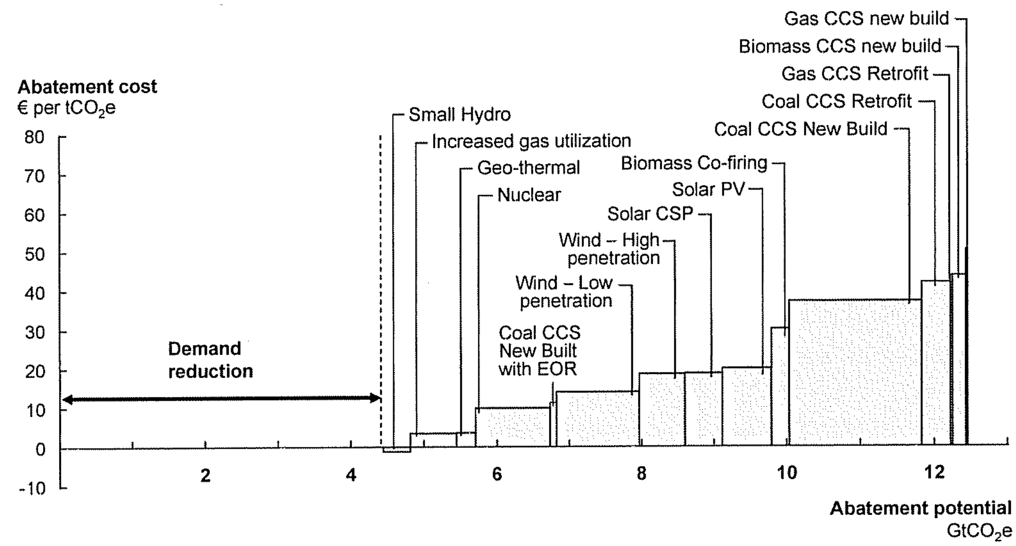
39 Only the cost of abatement levers within the Power sector is included, i.e. the cost of measures in other sectors that reduce electricity consumption is not included in this calculation

40 Our base case fuel price assumptions are taken from the IEA's *World Energy Outlook 2007*: oil at $60 a barrel (€40 a barrel), gas at €5 per MBTU, and coal at €40 per tonne. In the high price scenario, oil price is at $120 per barrel, gas at €9 per MBTU, and coal at €75 per tonne.

Exhibit 8.1.4

Global GHG abatement cost curve for the Power sector – Scenario B: 50% growth of renewables and nuclear energy

Societal perspective; 2030

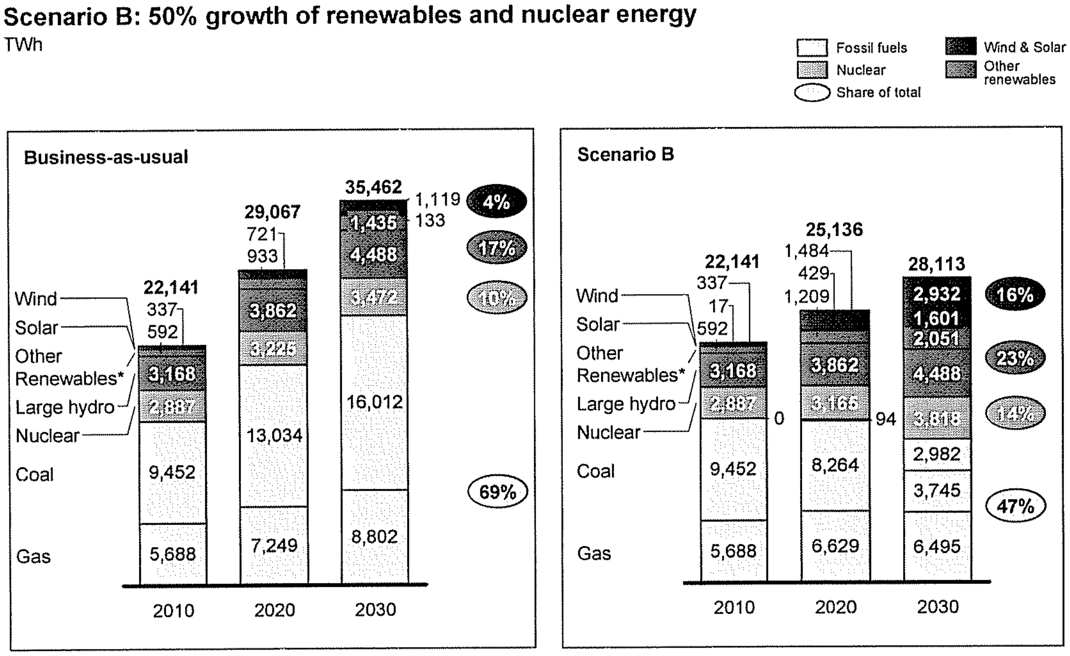


Note: The curve presents an estimate of the potential of all technical GHG abatement measures below €60 per tCO_2e if each lever was pursued aggressively, taking into account the supply assumptions of scenario B It is not a forecast of what role different abatement measures and technologies will play
Source: Global GHG Abatement Cost Curve v2 0

Exhibit 8.1.5

Production mix – Scenario B: 50% growth of renewables and nuclear energy

TWh



* Small hydro, geothermal and biomass
Source: Global GHG Abatement Cost Curve v2 0

The Power sector has many characteristics that make implementation less challenging than in most other sectors. First, the sector consists of a relatively small number of large companies, which are used to regulation and to taking regulatory incentives into account when prioritizing investments. Second, consumer implications are relatively limited (except for a potentially higher electricity price) and third, compliance is comparatively easy to measure and monitor.

Instead, the biggest implementation challenges seem to be related to technology and cost. Many of the key low-carbon technologies are not cost competitive today today and need to travel down the learning curve. If policy makers want to see utilities investing in them, they should design incentive systems that compensate for the higher cost and make investments in these emerging technologies attractive. There are also regulation-related implementation challenges in many countries: grid regulation often needs to be adapted to allow for integration of the new-generation technologies, permitting processes to build new power plants are often long, and the long-term development of the regulation is often highly uncertain – a problem for a business where assets often have a life time of several decades. Furthermore, utilities will need to learn how to build and maintain these new-generation technologies and how to integrate them in an effective way into existing energy systems.

8.2 Petroleum and gas

The Petroleum and Gas sector emits 2.9 $GtCO_2e$ per year, corresponding to 6 percent of total global 2005 CO_2e emissions (including indirect emissions).[41] In the absence of abatement measures, emissions from petroleum and natural gas production, transport, and refining are predicted to grow by one-third to around 3.9 $GtCO_2e$ per year by 2030. Upstream, midstream, and downstream segments each account for a large share of total emissions. A range of abatement options could reduce petroleum and gas emissions in 2030 to a level that is 14 percent below 2005 emissions – much of it at a net benefit to society. The three main abatement categories are process changes and improvements, mainly in non-OECD countries (around 250 $MtCO_2e$ per year); energy-efficiency improvements, mainly in downstream refining (about 350 $MtCO_2e$ per year); and Carbon Capture and Storage (CCS), mainly in downstream refining in OECD countries (approximately 450 $MtCO_2e$ per year). The main implementation obstacles are technological maturity and funding for CCS, the dispersed ownership of assets, misaligned incentives between companies and society, differences in capabilities between oil companies, and a shortage of capital and engineering capacity.

Business-as-usual emissions

For petroleum, the scope of this study includes production and refining activities. The scope excludes emissions from the sea freight of petroleum, which is covered in the Transportation sector analysis; petrochemicals, covered in the Chemicals sector; distribution, covered in Transportation; and marketing and final consumption that are covered in the Power, Buildings, and Transportation sectors. This analysis also excludes the exploration and development of petroleum as these do not produce material GHG emissions.

For natural gas, the scope of this study includes production, transmission, liquefied natural gas (LNG), and distribution. Emissions from sea freight and trucking of natural gas are covered in the Transportation sector analysis while retailing is covered in both the Power and Buildings sectors.[42] This analysis does not include the exploration and development of natural gas, gas-to-liquids (GTL), and coal-to-liquids (CTL) because their GHG emissions are too small to be material.

41 Indirect emissions are 0.3 $GtCO_2e$ and 0.4 $GtCO_2e$ in 2005 and 2030 respectively.

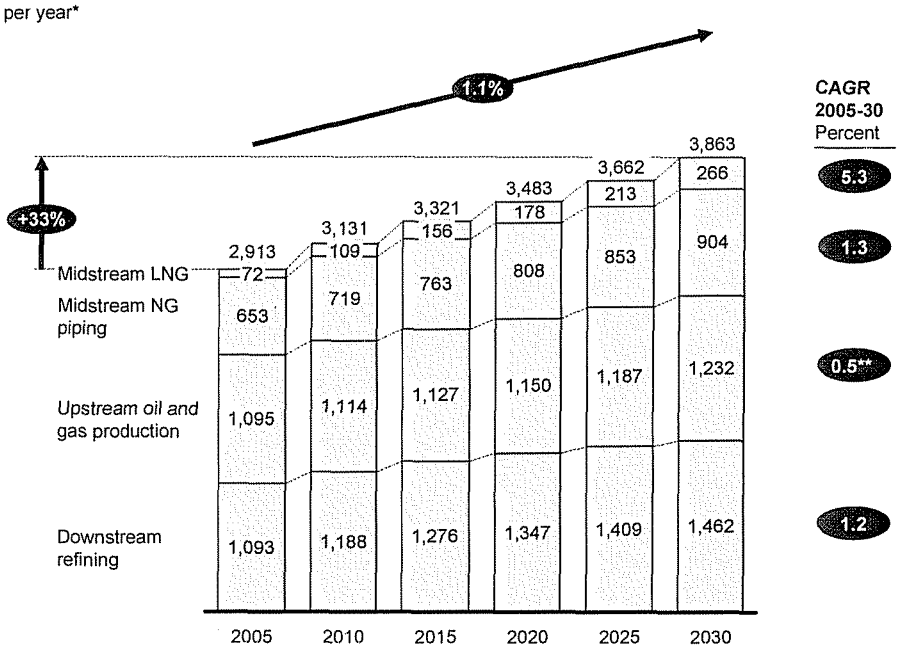
42 LNG boil-off is included in this analysis.

In the absence of abatement measures, emissions in the Petroleum and Gas sector are estimated to grow by 1.1 percent annually through 2030 to reach 3.9 $GtCO_2e$ per year (Exhibit 8.2.1). The BAU case (i.e., without abatement measures) assumes a portfolio shift away from conventionally produced oil; the share of natural gas in global upstream production will grow from 37 percent in 2005 to 41 percent in 2030, and the proportion of non-conventional oil will grow from 1 to 3 percent over the same period.

Exhibit 8.2.1

Business-as-usual emissions in the Petroleum and Gas sector

$MtCO_2e$ per year*



* Including indirect emissions

** Strong increase in production and processing emissions offset by a strong reduction in flaring emissions

Source: Global GHG Abatement Cost Curve v2 0

Emissions in 2005 from upstream and downstream operations each represented about 38 percent of total sector emissions, with midstream emissions accounting for the other 24 percent. Strong global demand for gas and fuel products between 2005 and 2030 is expected to drive overall growth in CO_2 emissions.[43] Demand in all oil and gas segments will be driven by rapid economic development in China, India, the Middle East, and Russia, as well as a shift to gas.

- **Upstream production and processing.** Demand is expected to grow by 47 percent between 2005 and 2030. Moreover, the energy intensity per barrel produced will increase due to a portfolio shift towards more energy-intense gas and non-conventional oil production and a greater need for enhanced oil recovery (EOR) and energy-intense artificial lift because of maturing oil fields.[44] Yet total upstream emissions will increase by only 12 percent, due to a strong anticipated reduction in flaring emissions (a decrease of some 72 percent). This is because of increasing public pressure to reduce flaring and the natural incentive caused by high gas prices. It is to be noted however,

43 Demand for gas in 2005 2030 is forecast to grow at 1.9 percent annually, for conventional oil at 1.2 percent, and for non-conventional oil at 4 7 percent.

44 The ratio of carbon intensity between non-conventional to conventional oil production varies based on the maturity of the fields. Non-conventional is estimated to have 2-5 times higher carbon intensity than conventional.

that there is a great deal of uncertainty about upstream emissions, particularly in respect of their non-CO_2 share in a 2030 perspective. For example, the EPA baseline considers that fugitive and venting emissions will grow with increasing oil and gas production, leading to non-CO_2 emissions higher than 1.0 $GtCO_2e$ per year by 2030. However, there is evidence that these emissions are already being reduced, as the effectiveness of investments in emissions reductions is high given the high global warming potential of methane. Thus, the BAU case in upstream assumes those fugitive and venting emissions to decrease significantly.

- **Midstream transmission and distribution.** The main emissions in this segment are the result of gas compression for gas transport and methane leakage during the transport and distribution of gas. As a result of a strong increase in total gas demand (60 percent) and a tripling of LNG, total midstream emissions will grow by around 60 percent between 2005 and 2030 in the BAU case. Although LNG is energy-intense on a per-barrel of oil equivalent (BOE) basis, its usage is more efficient than pipeline transport for long distances. LNG emissions during transport are only 10 to 20 percent of the total carbon content of gas.
- **Downstream refining.** Segment emissions are forecast to grow from 1.1 $GtCO_2e$ per year in 2005 to 1.5 $GtCO_2e$ per year in 2030 – a 1.2 percent annual growth rate. The increase in emissions is driven by strong throughput growth as well as increasing process complexity. However, the underlying trend towards more energy-efficient operations is expected to continue in the BAU case, driven by continued high energy costs.

BAU emissions for the overall Petroleum and Gas sector show much stronger growth in developing regions (60 percent in 2005–2030) than in developed regions (17 percent growth), reflecting a relative shift in upstream production and downstream refinery capacity towards those regions.[45] The Middle East, China, and India will account for more than 50 percent of this increase, resulting in a 27 percent share of global emissions from those countries/regions in 2030.

Carbon intensity, which is the ratio of CO_2 to energy (i.e., a measure of the "greenness" of different value chains), will vary greatly from region to region by 2030. Canada and Latin America (e.g., Venezuela) will show significantly higher carbon intensities in upstream production due to the relatively large share of non-conventional oil in their production portfolios. Latin America will also have the highest carbon intensity in downstream refining, primarily due to the heavier and more sour crude oil processed in the region.

This reference case is based on data from the International Energy Agency (IEA), United Nations Framework Convention on Climate Change (UNFCCC), the International Association of Oil & Gas Producers, and the Carbon Disclosure Project.

Potential abatement

Identified abatement levers could reduce 2030 emissions to a level that is some 4 percent below 2005 emissions (14 percent including the effect of reduction in fuel consumption due to abatement in transport sector), abating around 1.1 $GtCO_2e$ per year compared to the BAU case in 2030.[46] This report includes

45 The share of upstream production from the Middle East and Russia will grow from 39 percent in 2005 to 47 percent in 2030. The Middle East and the BRIC nations—Brazil, Russia, India, and China—will increase their share of global downstream refinery capacity from 19 percent in 2005 to 25 percent in 2030.

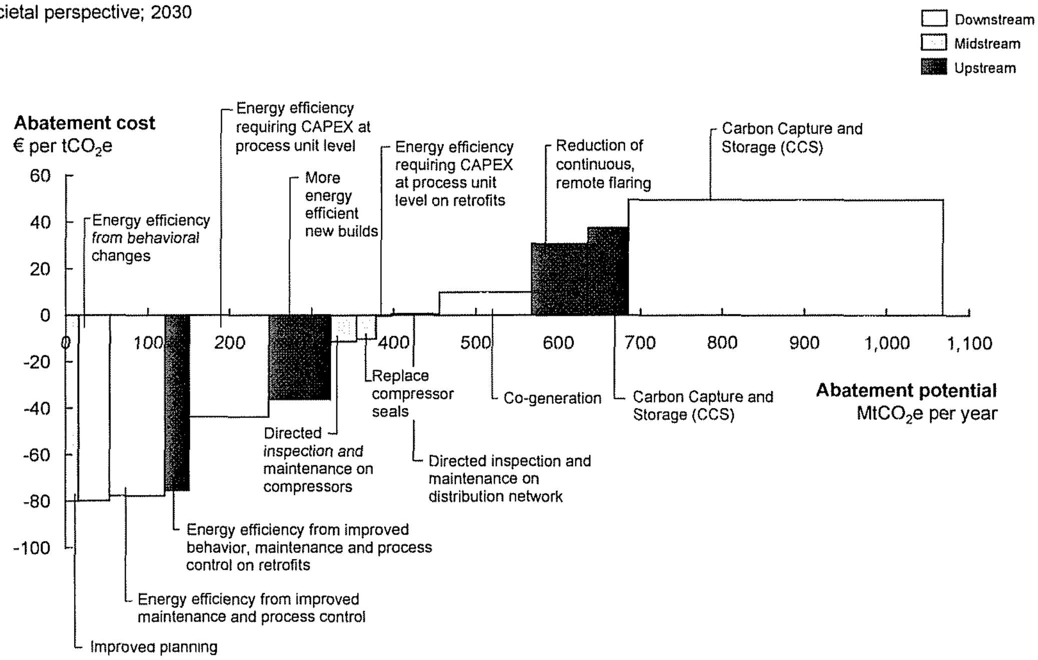
46 In addition to the effect of demand reductions from transport and including the reduction of indirect emissions (which are shown in the power sector as demand reductions).

four main categories of abatement (Exhibit 8.2.2): behavioral and simple process changes; energy-efficiency improvements; CCS; and reduced flaring (only for upstream). These levers encompass the large majority of the abatement potential. Several smaller possible levers exist, including the accelerated replacement of equipment such as compressors, but these have not been included in this analysis.

Exhibit 8.2.2

Global GHG abatement cost curve for Petroleum and Gas sectors

Societal perspective; 2030



Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €60 per tCO_2e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play.
Source: Global GHG Abatement Cost Curve v2 0

A. "Behavioral" and simple process changes. Across all three subsectors, improved maintenance and process control can result in significant abatement (of around 240 $MtCO_2e$ per year in 2030) and are net-profit-positive at assumed energy prices:

- In upstream, as well as conservation programs and improved maintenance, measures include reducing fouling build-up in pipes, optimizing well and separator pressures, and optimizing the spinning reserves of rotating equipment. Along with improved process control that reduces suboptimal performance, emissions can be reduced by around 30 $MtCO_2e$ in 2030.[47]
- In midstream, more directed inspection and maintenance of the compressors and distribution networks and better planning can reduce emissions by around 110 $MtCO_2e$ in 2030.
- In downstream, significant abatement (about 100 $MtCO_2e$ in 2030) can come from measures such as energy-awareness programs and optimized process controls in refineries that have not yet implemented large efficiency programs.

B. Energy-efficiency improvements. Modifications for energy efficiency could provide around 330 $MtCO_2e$ in emissions reduction, mostly net-profit-positive. These improvements would require capital expenditures at a process or plant level.

47 Due to undesired pressure drops across gas turbine air filters, an undesired turbine washout frequency, and suboptimal well and separator pressures.

- In upstream, a large abatement (about 90 $MtCO_2e$) can be achieved with a program developed to ensure that new-build production facilities are built to best-in-class standards in terms of energy efficiency.
- In midstream, seal replacement can deliver some 20 $MtCO_2e$ per year; other measures related to compressor replacement (e.g., accelerated replacement or electric compression) could provide additional abatement opportunities.
- In downstream, a reduction of around 100 $MtCO_2e$ per year can be achieved through the replacement, upgrade, and addition to equipment that does not alter the process flow of a refinery, e.g., through waste-heat recovery via heat integration and the replacement of boilers, heaters, turbines, and/or motors. Additionally, installing cogeneration units across the industry could provide an additional abatement of about 110 $MtCO_2e$ per year at a low positive cost.

C. **Carbon capture and storage (CCS).** CCS is the single-largest lever for abating oil and gas emissions, with a potential to abate 40 percent (around 430 Mt CO_2e) of total sector emissions in 2030, if enough resources – both in terms of capital as well as engineering capacity – are made available. CCS is most applicable for large point sources of CO_2 and has therefore the greatest potential in the downstream segment, notably at refineries that are close to storage and have the space and technical flexibility to integrate CCS. For upstream, CCS is considered particularly applicable to in-situ production of non-conventional oil where the energy required is produced in a centralized location.

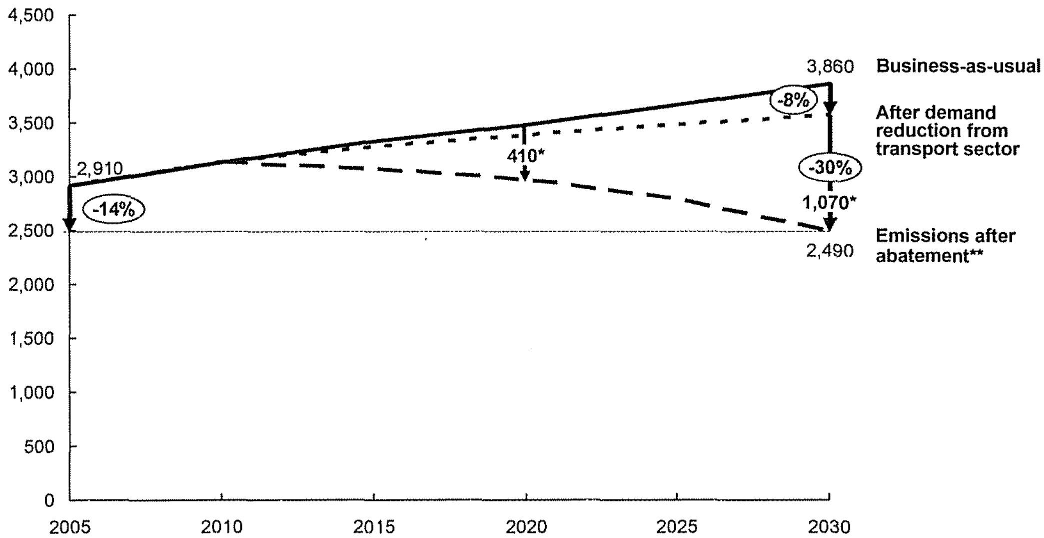
D. **Reduced flaring.** Despite very large anticipated reductions in flaring emissions in the reference case, a further abatement of about 70 Mt CO_2e will remain for flares located in remote regions.

As shown in Exhibit 8.2.3, the potential abatement volume increases over time, due to a gradual implementation of abatement levers in the industry. In particular, the first CCS pilot projects are

Exhibit 8.2.3

Emissions development for the Petroleum and Gas sectors

$MtCO_2e$ per year



* Reductions shown in the cost curve, thus calculated after demand reduction
** Economic potential of technical measures
Note: This is an estimate of maximum economic potential of technical levers below € 60 per tCO_2e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play
Source: Global GHG Abatement Cost Curve v2 0

forecast to be implemented in 2015 and subsequently rolled out on a larger scale.

At an assumed oil price of $60 per barrel (€ 40 per barrel), the average cost for all emissions abatement levers is expected to be around € 4 per tCO_2e in 2030, much higher than in previous years. Indeed, heavy investments in CCS, cogeneration, and measures to reduce continuous remote flaring counteract the net-profit efficiency measures in those later years. Yet from a societal point of view the abatement measures would largely pay for themselves. The fact remains, however, that for individual companies, some of the more expensive abatement measures might not be attractive from a financial perspective.

Socioeconomic view	**Average cost** (€ per tCO_2e)	**CapEx** (€ billion per year)	**OpEx** (€ billion per year)
2015	-24	6	-4
2020	-16	11	-10
2025	-5	14	-13
2030	4	18	-12

Most identified abatement levers require high upfront capital investments, followed by savings in operating expenditures due to reduced energy requirements. Investment requirements for all levers in 2030 would represent 2 percent of the total investment expected in the industry.

Geographical differences. Geographic regions around the world have comparable abatement potential, with North America (16 percent of total abatement), Eastern Europe including Russia (16 percent), and the Middle East (13 percent) having slightly larger shares of the global total than other regions.

The main drivers for emissions abatement differ significantly by region. CCS will be the main abatement lever in Western Europe (61 percent of the abatement potential through 2030), North America (56 percent), Latin America (55 percent), and OECD Pacific (59 percent). Broad energy-efficiency programs and cogeneration are the largest levers in China (62 percent of potential), the Middle East (62 percent), India (61 percent), and the rest of developing Asia (52 percent). In Africa, reduced flaring emissions will be the largest lever (30 percent of abatement potential). In Eastern Europe and Russia, reduced emissions from the gas-pipeline network will have the greatest abatement potential (33 percent).

Implementation challenges

Although this analysis includes a realistic technical implementation schedule for each abatement lever, certain obstacles can prevent companies and regulators from implementing these measures. Significant barriers exist both at an internal company level and at an external or regulatory level.

Internally, petroleum and gas companies face implementation challenges because of a lack of awareness, a scarcity of resources, and relatively high financial hurdle rates:

- For large companies, building increased awareness of the importance of energy conservation and CO_2 emissions reduction takes time and continued reinforcement. Conversations about energy conservation must become part of regular management systems, and high-level management attention is required for this focus to remain effective. Recent high energy prices will help in this respect but behavioral changes are always gradual.

- Monitoring of CO_2 emissions and the impact of the various measures is essential for the effective implementation of reduction programs. This is a challenge for all companies but especially for the upstream and midstream operations of large oil companies as they tend to have internationally dispersed operations in remote regions.
- With high energy-demand growth, resources are scarce within oil and gas companies. In many cases, companies will have to choose between allocating scarce capital and engineering capacity to their core business (such as finding more resources) or energy-conservation programs.
- The current knowledge and skills required to implement energy-efficiency programs differ significantly between companies. Building these skills or transferring them between companies will take time.
- Finally, many energy-efficiency measures may not pass companies' internal hurdle rates. For some opportunities, companies could consider lower hurdle rates, reflecting the different risk profile of some cost-saving opportunities, but in many cases additional guidelines and targets will be required to achieve higher reductions.

Differences between companies can be large, and the regulatory and public environment in which a company operates can have a substantial influence on which obstacles prove most significant and how a business responds.

External obstacles vary greatly between countries. As noted, some developing countries have insufficient oil and gas infrastructure, making implementation of abatement measures difficult or very costly. Moreover, fuel subsidies or the existence of stranded resources or export bottlenecks reduce the upside of adopting energy-savings measures. Stranded resources and export bottlenecks both imply too much fuel and/or a low local fuel price, both of which encourage the wasteful use of energy.

Moreover, the cost curve shows that CCS can provide the single-biggest reduction in CO_2e emissions for the Petroleum and Gas sector. However, given its early stage of development, much uncertainty on the potential of this technology still exists and multiple obstacles need to be overcome. For downstream, CCS still needs to enter the pilot phase and although individual CCS technologies are proven independently, they have not been applied in an integrated manner and on a large scale in a refining environment. Moreover, CCS requires significant funding as the initial plants are more expensive and storage availability will largely depend on the region. Finally, a clear regulatory framework will be required for the transport and storage of the gases, which does not yet exist in most regions.

In summary, abatement options for the Petroleum and Gas sector are well-known and feasible in the medium term. If these abatement levers are implemented, the Petroleum and Gas sector could maintain constant or even declining total emissions despite significant demand growth. However, execution of the measures will require the involvement of all major companies and governments.

8.3 Cement

The Cement sector represented emissions of 1.8 $GtCO_2e$ per year in 2005, which is approximately 4 percent of total global emissions and about 11 percent of worldwide industrial emissions.[48] China is the largest producer of cement and thus its related emissions, producing around 45 percent of the worldwide total in 2005. In the absence of abatement measures, cement emissions are projected to grow 3 percent annually through 2030, driven mainly by economic growth, infrastructure development, and urbanization in developing countries. Identified abatement levers would cut emissions by 25 percent relative to this BAU case. Most of the abatement potential is achievable using conventional technologies. The majority of abatement potential would be net-profit-positive to society. A challenge to a reduction of cement emissions is that we do not anticipate that the breakthrough technology of carbon capture and storage will be available before 2020 at the earliest.

Cement is the essential ingredient in concrete, the main building material for buildings and infrastructure. Concrete is second only to water as the most consumed substance on earth, with approximately 20 billion tonnes used annually by society. Cement is therefore important to economic growth and development and is a major industry in most regions of the world. Total global cement production in 2005 was approximately 2,350 megatonnes. Cement is predominantly a regional industry, although there is some international trade. Driven by its rapid economic growth and urbanization, China is by far the biggest country in terms of cement production and related CO_2 emissions, alone accounting for some 45 percent of global production in 2005. No other region produces more than 10 percent of the global total. An average cement plant typically emits around 1 $MtCO_2e$ per annum, and sources of emissions in the industry are relatively concentrated;

The main constituent of cement is clinker. This intermediate product is produced in a high-temperature process for the calcination and mineralization of limestone. Ordinary Portland cement is composed of about 95 percent clinker and about 5 percent gypsum, ground to a fine dry powder. Depending on the application, product qualities, and product and building standards, clinker can be substituted to different extents by other mineral components, including granulated slag from the steel industry, fly ash from coal-fired power plants, and natural volcanic materials, producing composite cements.

48 This category includes indirect emissions from electricity consumption of 0.2 $GtCO_2e$ per year.

There are three categories of CO_2 emissions from cement production:

- **Process emissions.** Direct emissions from the calcination process constituted some 54 percent of global cement CO_2 emissions in 2005.
- **Fuel-combustion emissions.** These direct emissions accounted for around 34 percent[49] of the total in 2005.[50]
- **Indirect emissions.** Related to electricity consumption, these emissions made up around 12 percent of the total in 2005.[51]

The clinker production process is the most CO_2-intensive aspect of the Cement industry, accounting for all process emissions and more than 80 percent of the emissions from fuel combustion. There are no material emissions of other GHGs by the cement industry.

The cement sector emitted 1.8 $GtCO_2e$ per year in 2005, which is 4 percent of total global GHG emissions. Emissions intensity and clinker content in cement differ substantially between regions, ranging from around 0.63 tCO_2e per tonne of cement in 2005 in Germany to some 0.81 tCO_2e per tonne in North America and even approximately 0.90 tCO_2e per tonne in Russia. The global average for carbon intensity from cement production in 2005 was 0.79 tCO_2e per tonne.

Business-as-usual emissions

In the BAU case, the Cement industry's absolute emissions will increase by 111 percent from 2005 to 2030 – i.e., 3.0 percent annually – to 3.9 $GtCO_2e$ per year. Global emissions will increase at a lower annual rate than global production of cement (3.2 percent annual growth in 2005–2030), due to a more efficient production base, as the least fuel-efficient cement kilns are retired and replaced with best-available technology (BAT).[52] In China, authorities have announced the retirement of all shaft kilns before 2020.[53] The reference case assumes this significant capital investment to update worldwide cement-industry assets from a BAT ratio of around 54 percent in 2005 to 97.5 percent in 2030. We assume that this asset-renewal process will harvest fully the technical potential to improve energy efficiency in clinker production. This major investment solely impacts fuel-combustion emissions but leaves process emissions unaffected. Carbon intensity will improve by 4 percent globally from 2005 to 2030 in the BAU case.

BAU growth in emissions is anticipated to be highest in the BRIC (Brazil, Russia, India, and China) economies and the rest of developing Asia and Africa, driven by rapid economic growth, infrastructure development, and urbanization. For example, emissions growth in India is projected at 8 percent annually, driven by increasing cement production. Growth in emissions is expected to be much slower in the developed world.

49 Accounting for CO_2e from biomass as climate-neutral and accounting for the CO_2e emission savings for society resulting from the recovery of waste as a source of energy.

50 Emissions related to transportation of cement materials and fuels are treated in the Transportation-sector analysis.

51 Reductions in indirect emissions are accounted for only if saved within the Cement sector; improvements in the Power sector are accounted for in that sector.

52 BAT for cement is a process using dry kilns with both pre-heater and pre-calciner.

53 Increased fuel energy efficiency due to retirement of the least-efficient kilns has been included in the BAU case.

The 2005 baseline and reference case emissions development are based on data from multiple sources, including the International Energy Agency (IEA), the Intergovernmental Panel on Climate Change (IPCC), the Cement Sustainability Initiative (CSI), and the European Cement Research Academy (ECRA), as well as scenario analyses by the authors. Reference case emissions calculations depend on cement demand and production and average clinker ratio forecasts by region.

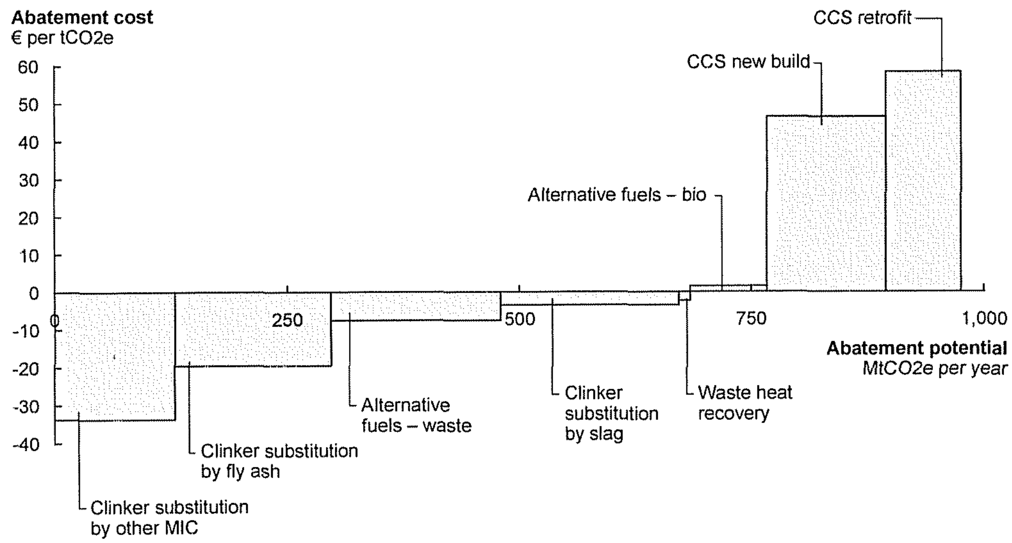
Potential abatement

We have identified eight abatement levers in the Cement sector, which we can aggregate into four groups (Exhibit 8.3.1):

Exhibit 8.3.1

Global GHG abatement cost curve for the Cement sector

Societal perspective; 2030



Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €60 per tCO_2e if each lever was pursued aggressively It is not a forecast of what role different abatement measures and technologies will play

Source: Global GHG Abatement Cost Curve v2 0

A. Increased substitution of clinker by mineral components in cement (50 percent of abatement potential, around 490 $MtCO_2e$ per year). Substituting clinker with granulated blast-furnace slag, fly ash, and other mineral components lowers all types of emissions from clinker production, including process, fuel combustion, and indirect emissions.[54] Compared with the clinker share of 82 percent in 2030 in the BAU case, the abatement case clinker share is estimated at 70 percent globally. The increased clinker substitution takes into account the regional availability of the mineral components, linked to actions in the steel and power sectors.[55] In the abatement scenario, all blast-furnace slag from the steel industry will be granulated and sufficient fly ash from coal-fired power stations will be dry-discharged.

54 The only exception is clinker substitution with slag for which power consumption and consequently indirect emissions go up.

55 We assume coal production that is higher than 2005 levels. In the event that the Power sector succeeds in decreasing coal consumption significantly or keeping it at the 2005 level, the Cement sector abatement potential for fly-ash substitution for clinker may need to be revised

We account for the different clinker substitution potential of the mineral components (i.e., the K-factor of slag, fly ash, and other MIC).

B. **Increased share of alternative fuels in the fuel mix (27 percent of abatement potential, around 260 MtCO_2e per year).** Substituting conventional fossil fuels by alternative fuels, such as municipal and industrial waste and biomass, in the cement kiln reduces average direct fuel-combustion emissions of the clinker-making process. The estimated abatement potential assumes that: (a) CO_2 from biomass is climate-neutral; (b) the real reductions of CO_2 emissions at the alternative waste-disposal operations are attributed to the Cement sector;[56] and (c) sufficient waste and biomass is available locally to replace fossil fuels at an energy substitution rate of 33 percent in total (25 percent from waste and 8 percent from biomass), compared with less than 5 percent globally in the BAU case.

C. **Carbon capture and storage (CCS) (22 percent of abatement potential, around 210 MtCO_2e per year in net terms or around 290 MtCO_2e per year at the source).** CCS is the capture of CO_2 from a point source such as a cement kiln and its subsequent sequestration through methods such as injection into subterranean formations for permanent storage. CCS can be added to new cement-production facilities or retrofitted to existing plants. CCS technology is in an early stage of development and CCS transport infrastructure has yet to build out. CCS is assumed to be available starting in 2021 for newly built plants and from 2026 for retrofits of existing capacity. The total global share of production capacity equipped with CCS in 2030 corresponds to some 10 percent of total CO_2 production capacity.[57]

D. **Waste-heat recovery (1 percent of abatement potential, around 12 MtCO_2e per year).** Usage of excess heat from the clinker burning process for electricity generation reduces electricity consumption from the power grid by 15 kWh/t clinker on average and thus lowers indirect emissions.

E. **Energy efficiency improvement in clinker kilns.** This abatement lever is exhausted in the BAU case through clinker-asset renewal; no additional energy-efficiency improvement potential is considered in the abatement case. The capital investments related to asset-renewal programs toward BAT contribute about 210 MtCO_2e of abatement. Therefore, clinker renewal is an important abatement lever to be implemented. Additional energy-efficiency measures for existing and new plants seem possible beyond clinker-asset renewal, but we have not analyzed this due to the fact that we anticipate that the additional potential is small.

The identified abatement measures for the Cement sector, including CCS, would eliminate 1.0 GtCO_2e per year by 2030, lowering sector emissions to 2.9 GtCO_2e per year worldwide – a 25 percent reduction from the BAU case. The abatement case results in total absolute emissions in 2030 that are 58 percent higher than in 2005 (relative to 120 percent growth in cement volume).[58] Without CCS, cement-industry CO_2 emissions will increase 70 percent above the 2005 baseline. The potential abatement volume increases over time due to an increasing implementation rate of abatement measures. With all abatement measures in place by 2030, cement emission levels would almost be stabilized at 2010 levels (Exhibit 8.3.2).

Almost 80 percent of the abatement potential in 2030 is based on conventional technologies such as clinker substitution and alternative fuels, but excluding CCS.

56 In the abatement case, the fossil waste would be used by the cement industry. In the BAU case, it would be incinerated in waste-incineration plants for electric power production.

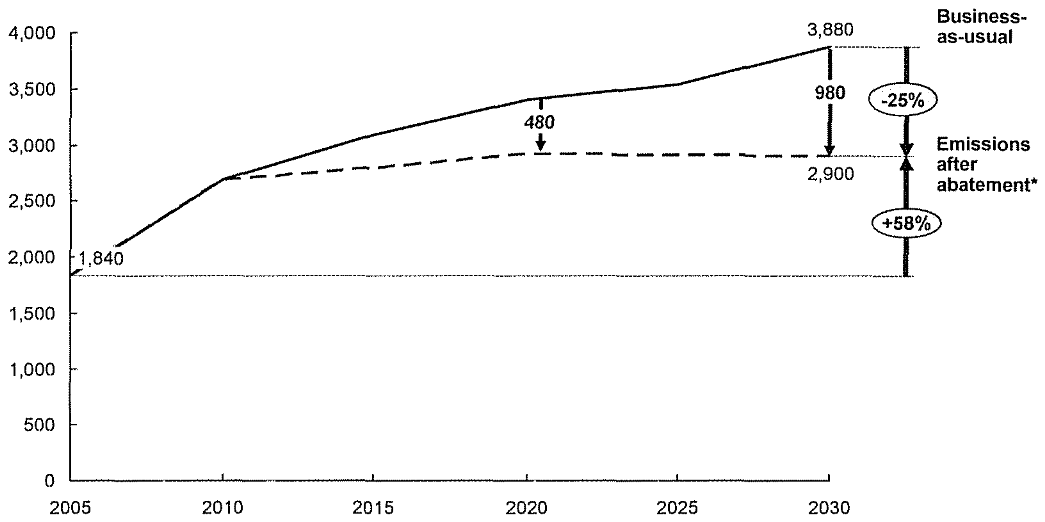
57 Direct emissions to be captured are about 290 MtCO_2e per year; assuming approximately 85 percent capacity utilization would require some 340 MtCO_2e per year of installed capture capacity.

58 The direct emissions (process and fuel combustion) in the abatement case are 41 percent higher and indirect emissions from electricity are 101 percent higher than in 2005, due to increased electricity needs for CCS processes.

Exhibit 8.3.2

Emissions development for the Cement sector

$MtCO_2e$ per year



* Economic potential of technical measures

Note: This is an estimate of maximum economic potential of technical levers below € 60 per tCO_2e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play

Source: Global GHG Abatement Cost Curve v2.0

The average CO_2e productivity of the Cement sector increases significantly in the abatement case. The CO_2e per tonne of cement decreases from an average of 756 kg CO_2e per tonne in the 2030 BAU case to an average of 566 kg CO_2e per tonne in the 2030 abatement case, equaling a decrease of more than one-quarter compared with 2005 levels (Exhibit 8.3.3). When accounting solely for direct emissions (fuel combustion and process), the carbon intensity decreases from 680 kg CO_2e to 490 kg CO_2e per tonne of cement.

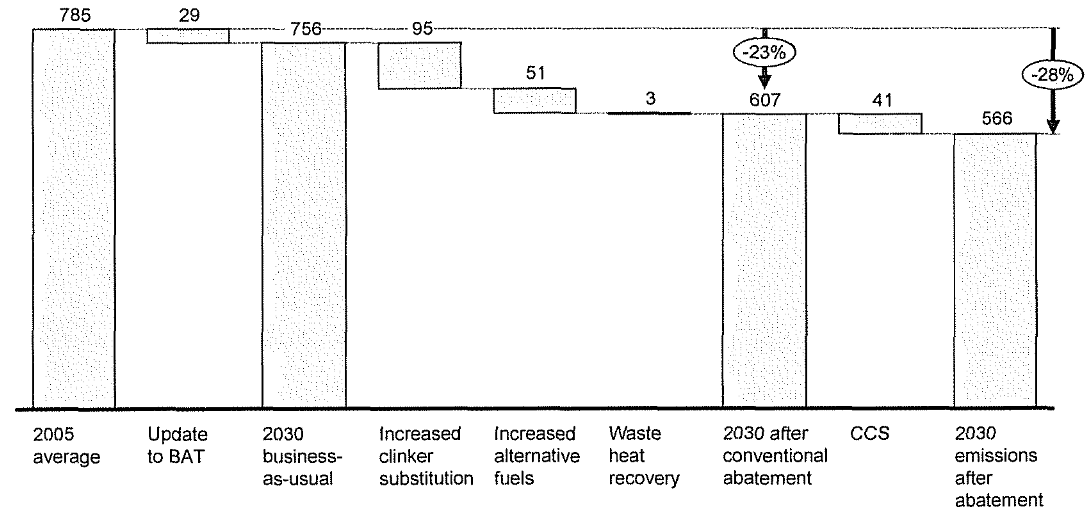
The average cost to society for all abatement measures is negative – i.e., society secures a saving. This is because an extensive substitution of clinker will decrease, to some extent, the need for new builds of clinker-production capacity. Furthermore, the increasing use of waste as a fuel will cut the cost to society of disposing of its domestic and industrial waste. The average cost of abatement will rise starting after 2020 as cost-positive CCS systems become part of the total abatement. All levers based on conventional technology (i.e., excluding CCS) are net-profit-positive or neutral in terms of cost to society and have a negative cash flow. CCS will require capital investments.

Socioeconomic view	**Average cost** (€ per tCO_2e)	**CapEx** (€ billion per year)	**OpEx** (€ billion per year)
2015	-15	-9	-2
2020	-14	-5	-4
2025	-11	-1	-5
2030	1	6	-2

Exhibit 8.3.3

Cement CO_2e intensity development by abatement lever group

Kg CO_2e per tonne cement; Global average



Source: Global GHG Abatement Cost Curve v2 0

Capital expenditures in the cement industry are driven by the reduced build-out of clinker production capacity (i.e., the difference between investments for clinker-production assets and investments for using fly ash and slag, leading to negative values to society), increased investment related to increased usage of waste and biomass alternative fuels, higher investment for fly-ash dry discharging and slag granulation and grinding, and CCS capacity build-out after 2020. Operating expenditures in cement are driven by material and transport costs for clinker replacement and additional grinding costs related to grinding slag, fuel costs (especially for alternative fuel levers), and electricity costs.

Not all abatement measures will be equally implemented across regions since implementation relies on feasibility and availability. We find the largest abatement potential in regions with a high clinker share in the reference case and a greater potential availability of substitutes. Approximately 37 percent of the total global abatement potential is found in China (whereas cement production in China accounts for 50 percent of global production), more than 22 percent in India, and more than 10 percent in the rest of developing Asia.

Implementation challenges

Several conditions are required for the cement emissions abatement levers to succeed:

- **Policies and regulations.** Cement product standards and building codes need to be revised so that these focus on product performance rather than composition to enable the increased usage of composite cements. Policies should allow the exhaustion of waste coprocessing in cement before other solutions such as incineration and landfilling are considered.
- **Availability of materials.** For blast-furnace slag to be substituted for clinker, slag must be made available at a higher granulation rate than is currently the case in the steel industry. The abatement case for the cement sector assumes 100 percent granulation at high quality of all blast-furnace slag from blast-furnace steel production. For fly ash to be substituted for clinker, it must be made available at a higher usable share than is currently available from the Power sector. We base the abatement potential for 2030 on usage of approximately 600 Mt of high-quality fly ash globally. For waste to be used as kiln fuel at the projected abatement-scenario level, waste collection and pre-treatment must provide 25 percent of the global fuel-energy demand of the cement industry. Biomass availability for 8 percent alternative fuel usage also needs to be ensured, given likely competition between sectors. We have taken account of the total biomass availability in all sectors in this study. Overall, capturing the abatement potential in the cement sector depends on supportive actions in other sectors.
- **Avoid carbon leakage.** Asymmetric regulations in certain regions of the world while such regulations remain absent elsewhere could have a counterproductive effect on Cement sector emissions, if this meant that producers shifted production capacity or simply built new capacity farther from target markets due to lower production costs at the expense of higher transport costs. Additional emissions from shipping farther distances would be generated.
- **Technology and infrastructure.** CCS technology is in an early phase of development and must be tested for rollout in the cement industry by 2020. CCS transport infrastructure (pipelines and storage capacity) must be built out in parallel.
- **Sustainable construction.** Suitable policies and practices are critical to achieving further indirect reduction of emissions, including sustainable-construction designs, building codes, and eco-efficient building materials that would allow considerably higher energy efficiency in buildings and infrastructure.

To harvest the full abatement potential described in this report, we assume that all conditions are perfectly aligned and all obstacles are removed. The full potential that we have described is plausible despite all the implementation challenges. It is notable that, in 2006, the cement industry's fifth percentile of best-performing producers had already achieved the emissions intensity of the 2030 abatement scenario and there is every opportunity for all producers to perform according to 2006 BAT in 2030. CCS, if proven viable, will account for the rest of the emissions abatement.

8.4 Iron and Steel

The Iron and Steel sector accounts for 2.6 $GtCO_2e$ per year, about 6 percent of total global emissions and about 16 percent of worldwide industrial emissions in 2005. Of this total, 2.1 $GtCO_2e$ per year comes from direct emissions from iron and steel production and 0.5 $GtCO_2e$ per year relates to power consumption. Without the adoption of abatement measures, global emissions from the Iron and Steel sector are projected to grow by 3.2 percent annually, increasing emissions to 5.6 $GtCO_2e$ per year by 2030 primarily as a result of increased production. As the largest producer of iron and steel, China will represent 55 percent of global sector emissions in 2030. With the implementation of identified abatement levers, emission levels can be stabilized at the 2010 level, abating 1.5 $GtCO_2e$ per year (27 percent) compared to the 2030 BAU case. The major abatement levers are improving energy efficiency (the single-largest lever) and Carbon Capture and Storage (CCS) if this technology becomes available.

Iron and Steel is an important industrial sector and a key component of many other industries. The industry is highly fragmented, with the top 10 companies accounting for only 25 percent of total production. As in many other arenas, China is the biggest producer currently; its share is expected to grow from 31 to 44 percent of global production by 2030 (followed by India, Western Europe, and Russia with 15, 8, and 4 percent shares respectively). Iron and steel industry production is anticipated to more than double by 2030, primarily due to rapid economic growth and urbanization in the developing world. But the differences between regions will be stark. While China is forecast to account for 179 percent of emissions growth through 2030, the United States, Italy, Germany, and France are all expected to see declines in their share of emissions by 2030.

Two iron and steel production technologies are widely used: blast furnace/basic oxygen furnace (BF/BOF, the "integrated" route comprised of blast furnace and basic oxygen furnace), and electric arc furnace (EAF). In the BF/BOF process, iron ore is reduced in the blast furnace by the use of coke and pulverized coal injection (PCI) to form hot metal, which is then treated in a basic-oxygen furnace to remove impurities with oxygen and produce steel. An EAF uses primarily scrap metal that is melted by the energy produced by very high-current electricity. As an alternative to scrap metal, Direct Reduced Iron (DRI), produced with coal or gas) is used increasingly in the EAF process. Open hearth furnace (OHF) is a third, older steel-making technology still in use in the developing world (mainly in Russia and former Soviet states) that is expected to be discontinued over the next decade.

There are two forms of carbon emissions from iron and steel production:

- **Process and fuel-combustion emissions.** These direct emissions, primarily from the BF/BOF process, constituted 84 percent of total iron and steel GHG emissions in 2005.
- **Indirect emissions.** Mainly related to electricity consumption in the EAF process, these emissions make up 16 percent of the total.

The integrated BF/BOF process is the most CO_2e-intensive process, emitting around 1.6–2.8 tCO_2e per tonne of steel (excluding coke/sinter-making and after-treatment), compared with about 0.6–1.8 tCO_2e per tonne of steel for EAF steel-making, excluding after-treatment; (EAF emissions depend heavily on how the electricity is produced). The Iron and Steel sector emitted a total of 2.6 $GtCO_2e$ annually in 2005.

Business-as-usual emissions

Without abatement measures, global emissions from the Iron and Steel sector are forecast to grow by 3.2 percent annually, reaching 5.6 $GtCO_2e$ per year in 2030 – a 118 percent increase over 2005 emissions. Global production of iron and steel is expected to grow at a slightly higher rate than emissions by 3.4 percent annually between 2005 and 2030, from around 1,100 million tonnes to some 2,550 million tonnes. China will account for 55 percent of the growth. The emissions anticipated in the BAU case will grow strongly in Asia but decline in the United States and Western Europe, due to demand and shifts in production technology.

The 0.2 percent difference between industry annual growth and emissions growth is due to ongoing industrial energy-efficiency programs. The historic trend of 1 percent annual improvements in average global emissions intensity is unlikely to continue as future energy-efficiency programs will produce lower returns as absolute performance gets better and as the improvement potential of new greenfield assets is more limited than that of more dated assets. Another factor is the growing rate of iron and steel production in Russia, former Soviet states, and Asia, where carbon intensities are higher than in the Western hemisphere. We assume that net-profit-positive energy-efficiency measures are captured in the BAU case, given high competitive pressure in the industry.

The higher level of emissions in developing countries is caused by a combination of higher energy intensities due to less focus on energy efficiency historically, and higher carbon intensity per steel unit due to the more extensive use of low-quality materials (iron ore and scrap) in steel production as well as in direct fuel.

A shift is expected to take place from BF/BOF technology to EAF technology in the BAU case – from EAF share of 32 percent in 2005 up to an EAF share of 38 percent in 2030. However, this potential is limited by the available supply of scrap, the raw material used in EAF steel production. Less mature technologies such as CCS and coke substitution in the BOF process are not included in the BAU case.

We base the BAU case on regional production data and forecasts from the McKinsey Basic Materials Institute. Baseline emissions data were taken from sinter- and coke-making (for the BF/BOF process), steel-making (for BF/BOF, EAF, and OHF), and the after-treatment process, which comprises the heating and rolling of the steel.

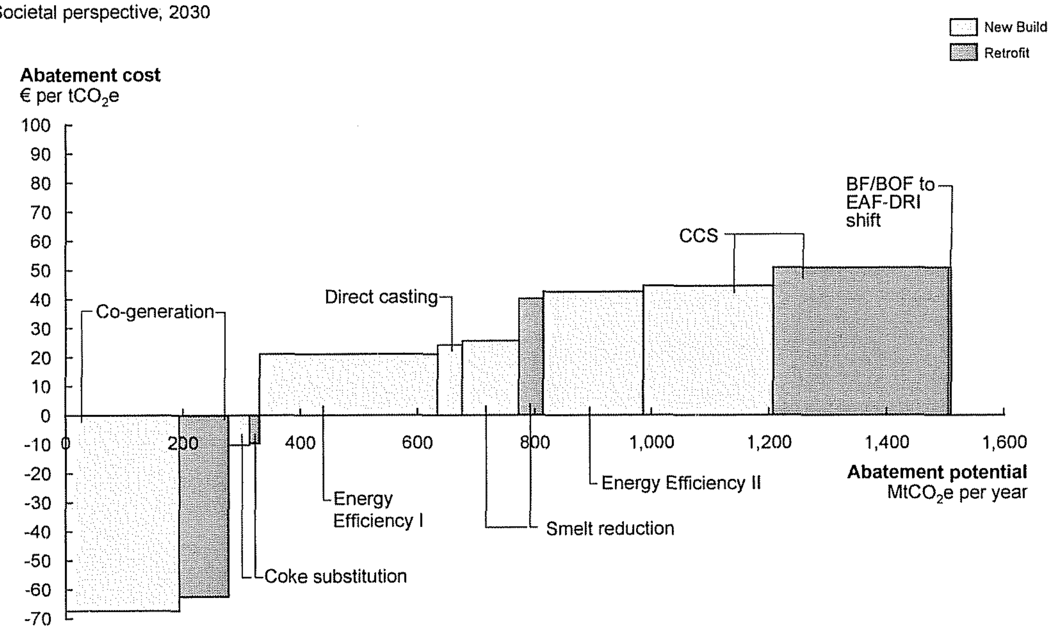
Potential abatement

We have identified a total of eight abatement levers for the Iron and Steel sector. If all abatement levers were to be implemented by 2030, emissions would be reduced by 27 percent, or 1.5 $GtCO_2e$ per year, compared to the BAU case. We can divide these levers into four groups (Exhibit 8.4.1):

Exhibit 8.4.1

Global GHG abatement cost curve for the Iron and Steel sector

Societal perspective, 2030



Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €60 per tCO_2e if each lever was pursued aggressively It is not a forecast of what role different abatement measures and technologies will play
Source: Global GHG Abatement Cost Curve v2 0

A. Energy-efficiency measures (62 percent of abatement potential, 930 $MtCo_2e$ per year). This first category accounts for 32 percent of the total abatement potential (about 480 $MtCO_2e$ per year), achieveable through integrated energy efficiency measures. We group this category into two bundles that have different costs. The cheaper bundle includes, for example, continuous improvement measures, preventative and better planned maintenance, the insulation of furnaces, improved process flows, sinter plant heat recovery, coal-moisture control, and pulverized coal injection. The other, more expensive, bundle includes, for example, oxygen injection into EAF, scrap preheating, flue-gas monitoring systems, improved recuperative burners, and BOF gas recycling.

In addition, technological changes (some limited by available technology, commercial constraints, product specification constraints) like Direct casting, integrating casting and after treatment process steps into one step, can lead to some 3 percent of total abatement potential (about 40 $MtCO_2e$ per year). We assume an average energy saving of 18 percent in after-treatment energy consumption for new-build plants. Cogeneration could create a further 18 percent of the total abatement potential (around 270 $MtCO_2e$ per year), assuming that BF/BOF steel mills can be self sufficient with regard to electricity by implementing this lever. Cogeneration is a method in which gas from the BF/BOF process is recovered, cleaned, and used for power generation at the steel mill. Smelt reduction, where ore reduction and steel production are combined in the same equipment, can contribute around a further 9 percent (about 140 $MtCO_2e$ per year) of abatement. In total, these energy-efficiency measures, combined with the efficiency effects in the BAU case can lead to a total energy-consumption improvement of 15 to 20 percent, with regional variations within this range.

B. **Fuel shift.** Substituting coke used in BF/BOF furnaces with fuel based on biomass (charcoal) can lead to 3.5 percent of abatement potential, some 55 $MtCO_2e$.

C. **Process change.** Switching more aggressively from BF/BOF to EAF compared with the BAU case could yield 0.3 percent, or around 4 $MtCO_2e$ per year, of abatement potential. Since EAF technology cannot use iron ore per se as a raw material, and the supply of scrap metal used tends to be limited (as steel is recycled after an average 10 to 20 years depending on the application), emissions reductions are made when switching to EAF-DRI. In this case, natural gas is used to reduce iron ore, producing direct reduced iron (DRI) that can substitute for scrap as the raw material in EAF furnaces. The use of this methodology is a more costly production alternative in most regions because of the use of gas as fuel. For this reason, the BAU case assumes that this shift does not take place. (Some regions such as the Middle East are structurally advantaged in this respect and can use the gas for many uses. Other regions, such as Siberia, Kazakhstan, Iran, and Iraq, have iron ore and stranded gas with limited alternative-usage options and could therefore be interested in developing this methodology).

D. **Carbon Capture and Storage (CCS) (34 percent of abatement potential, around 520 $MtCO_2e$ per year).** In this category, retrofitting CCS could abate around 300 $MtCO_2e$ per year and new builds around 220 $MtCO_2e$ per year. CCS isolates CO_2 after it has been emitted from a point source such as a blast furnace through injection into deep geological formations for permanent storage. The capture would occur after combustion, with chemical reactions cleaning the exhaust gases of CO_2. CCS is assumed to be applicable only for the integrated method of steelmaking. CCS is an immature technology today, and abatement potential will be limited by the possibilities for scaling up production and engineering skills. We assume that, for newly built steel plants, CCS would yield a 90 percent capture rate of CO_2 and 72 percent of new-build plants would be equipped with CCS in 2030 (90 percent of plants reaching sufficient scale and 80 percent of plants located close enough to a potential storage area). For retrofit CCS, many older plants are excluded from the potential because of technological constraints, leaving 40 percent of older plants suitable for CCS. Around 25 percent of all steel mills are expected be equipped with CCS in 2030. We should note that these numbers are dependent on the technology becoming industrially and commercially viable, which is yet to be proven.

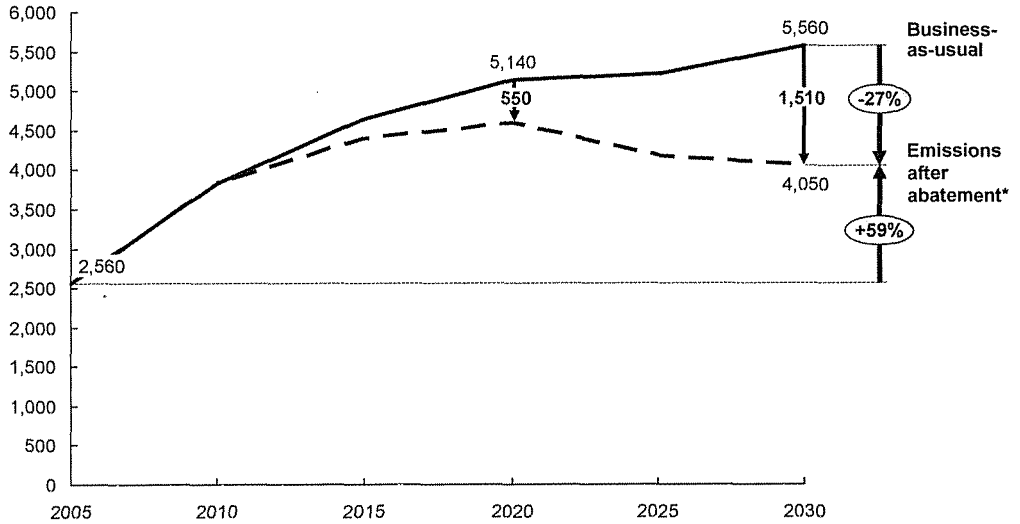
The identified abatement measures for the Iron and Steel sector can eliminate 1.5 $GtCO_2e$ per year worldwide by 2030, lowering industry emissions to 4.1 $GtCO_2e$ per year. This is a 27 percent reduction from the BAU case and would reduce 2030 emissions to the same level as 2010 emissions. The potential abatement volume increases over time due to an increasing implementation rate of the measures (Exhibit 8.4.2).

The investment needed to achieve the total abatement potential for the Iron and Steel sector is around € 23 billion per year from 2011 to 2020, increasing to about € 34 billion per year in 2021 to 2030 with the adoption of CCS that we have modeled. The global average cost is about minus € 2 per tCO_2e in 2015, turning positive thereafter and increasing to about € 17 per tCO_2e by 2030, mainly due to CCS. Taking the abatement levers individually, they range from offering negative costs to society and imposing positive costs. Fuel substitution from coke to biobased material such as charcoal could come at a negative cost, although this depends on the future relative price of these fuels. Energy-

Exhibit 8.4.2

Emissions development for the Iron and Steel sector

$MtCO_2e$ per year



* Economic potential of technical measures

Note: This is an estimate of maximum economic potential of technical levers below € 60 per tCO_2e if each lever was pursued aggressively
It is not a forecast of what role different abatement measures and technologies will play

Source: Global GHG Abatement Cost Curve v2 0

efficiency measures and process change can require high upfront investments but typically between 30 and 50 percent of these measures can be realizable with limited investments. Such measures lead to both operational cost savings (fuel savings) and CO_2 abatement. CCS will require high capital and operational investments, since transportation of CO_2 incurs an operational expense.

Socioeconomic view	**Average cost** (€ per tCO_2e)	**CapEx** (€ billion per year)	**OpEx** (€ billion per year)
2015	-2	23	-7
2020	-2	31	-17
2025	14	33	-11
2030	17	34	-9

After abatement, carbon and energy intensity will converge but still vary across regions due to different production techniques (e.g. different relative shares of BF/BOF versus EAF) and pollution policies. China, for example, could realize a reduction of 35 percent in carbon intensity, down from 2.7 to 1.7 tCO_2e per tonne of steel, whereas in North America the reduction would be from 1.4 to 1.1 tCO_2e per tonne of steel.

Implementation challenges

The analysis above is based on a "constraint-free" viewpoint but it is the case that commercial, technical, organizational, and regulatory challenges need to be addressed. In order for the iron and steel industry to adopt abatement measures, players must be able to realize economic benefits, either directly or by avoiding penalties. Additionally, the necessary state-of-the-art technology must be available. Significant changes to the business environment must occur if a truly radical transformation of the industry is to occur.

- **Capturing energy efficiency.** Improving energy efficiency and driving towards more energy-efficient processes has been, and will remain, one of the focuses of the Iron and Steel industry. Recent work to identify attractive energy-reduction options has consistently shown that significant potential, typically in the order of 10 to 15 percent of total energy costs, can be captured with paybacks of less than two years. These energy savings necessarily result in lower GHG emissions too. The primary barriers to realizing these opportunities are typically organizational. Given sufficient cost pressure due to a softening market environment or significant energy-price escalations, companies are likely to pursue these net-profit-positive abatement opportunities. We have therefore accounted for this potential in the BAU baseline.
- **Significant investment requirement.** Most companies already understand the rationale of switching to different approaches to cast and roll some specific steel products, e.g., direct casting. However, such technology changes may imply high switching costs and some level of risk, particularly if market conditions are uncertain or credit tight. When we also factor in cost escalations due to deteriorating raw-material quality, cash availability for large-scale investments can become a real constraint. Over the long term, positive returns on projects of this type are likely to enable a gradual migration to these technologies; the challenge lies in finding the right incentives to encourage them to move ahead more quickly.
- **Regional competitive effects.** Current regional competitive differences could further increase due to potential asymmetric regulations. This would pose an even greater challenge to those players that today suffer from competitive disadvantages as they seek to change from the status quo and adopt emission-reduction technologies that come at a net cost. It is therefore likely that some kind of incentive mechanisms or interventions will be needed to enable necessary shifts to take place.
- **Technologies and infrastructure maturity.** CCS technology holds great promise for emission reductions but this technology is still in the earliest phases of development and is unlikely to be ready for rollout in the industry until at least 2020.

8.5 Chemicals

The Chemicals sector contributes significantly to climate change by being directly responsible for about 15 percent of all global industrial GHG emissions, or about 2.4 $GtCO_2e$ per year in 2005 (corresponding to around 4 percent of all man-made GHG emissions, including indirect emissions).[59] Emissions are forecast to increase by 122 percent to 5.3 $GtCO_2e$ per year in 2030, which on an annual basis (3.2 percent) is only slightly below the forecast for Chemicals demand growth (3.4 percent). A significant portion of this growth – approximately 28 percent – stems from ozone-depleting substitutes (ODS), which are unique in that they arise not as a byproduct of chemicals production but rather are released at the end of their lifecycle from downstream products using them (e.g., refrigeration units). If the Chemicals industry implemented all identified abatement levers by 2030, it would reduce emissions by about 2.0 $GtCO_2e$ per year (a 38 percent decrease compared with the BAU case). Emissions would stabilize at 3.3 $GtCO_2e$ per year, corresponding to 2015 levels. Abatement in Chemicals is characterized by high upfront investments but also by large and increasing operational-cost savings as a result of reduced energy needs and increasing energy prices. Given its strong position in chemicals production and the comparatively high intensity of its emissions, China has both the highest share of emissions and an even greater share of the abatement potential (about 40 percent).

The chemicals industry has substantially reduced its GHG-emissions intensity over the last 15 years. Since 1990, while chemical-industry volumes have grown by 3.2 percent a year, emissions have increased by only 1.7 percent annually. The reason for this is largely improved energy efficiency, debottlenecking, improved asset utilization, and other active measures to reduce GHG emissions. However, there are regional variations. While Europe and North America demonstrate little or no absolute emissions increases, developing countries and other regions have significantly increased their emissions, mostly driven by strong volume growth.

Business-as-usual emissions

Chemical sector emissions are expected to grow at an annual rate of about 3.2 percent through 2030 in the BAU case (i.e., without abatement measures), fuelled both by strong production growth and by

59 Indirect emissions represent 0.8 and 1.6 $GtCO_2e$ in 2005 and 2030, respectively

a shift in production to more carbon-intense regions, especially China. China will increase its share of global chemicals production from 27 percent in 2005 to 34 percent in 2030.

The rapid decarbonization of chemicals production that we have seen in recent years is not expected to continue at the same rate due to the declining marginal effect of efficiency measures and a shift of production to Asia, where coal is increasingly used as the primary fuel. Looking ahead, only a 0.2 percent annual decarbonization is believed to be achievable unless the more aggressive actions to reduce the carbon footprint from the chemicals industry described in this report are undertaken. Total BAU case emissions from the Chemicals sector will grow to about 5.3 $GtCO_2e$ per year in 2030, an increase of 122 percent compared with 2005.

We can split emissions from the chemicals industry into three categories:

- **Process emissions** released directly during the production process (often stoichiometric releases) accounted for around 40 percent of total chemicals emissions in 2005. Current emissions are calculated based on production volumes of selected chemicals that release GHGs during the production process (e.g., adipic acid, nitric acid, and ammonia). For each production process, region-specific emissions factors are used to calculate emissions (mostly from IPCC data). Future emissions are forecast to grow proportionally with production volumes (based on American Chemistry Council projected growth rates). A significant portion of process emissions (approximately 47 percent in 2030 in the BAU case) are associated with ODS substitutes, the set of products developed to replace hydrochlorofluorocarbons (HCFCs), largely in refrigeration applications. These emissions are unique in that they are not byproducts occurring at the production site but rather the emissions of the chemical products themselves when the downstream products of which they are a part reach the end of their lives. Thus, abating these emissions is out of the direct control of the Chemicals industry and rather must be achieved through improved recycling initiatives and the like.
- **Direct emissions** from fuel combustion to generate heat and/or electricity at the production site accounted for about 26 percent of 2005 emissions. To assess current emissions, we use IEA country data on fuel consumption of the chemicals industry and specific emissions per fuel. For future emissions, we assume that growth is in line with production forecasts, minus BAU energy-efficiency measures.
- **Indirect emissions** released by the Power sector but caused by the Chemicals industry by consumption of electricity accounted for some 34 percent of 2005 emissions. Similar to the calculation of direct emissions, we calculate the baseline of current indirect energy need using IEA data. We derive the carbon intensity of electricity from the Power sector model; future emissions include BAU decarbonization in the Power sector and energy-efficiency improvements in the Chemicals sector.

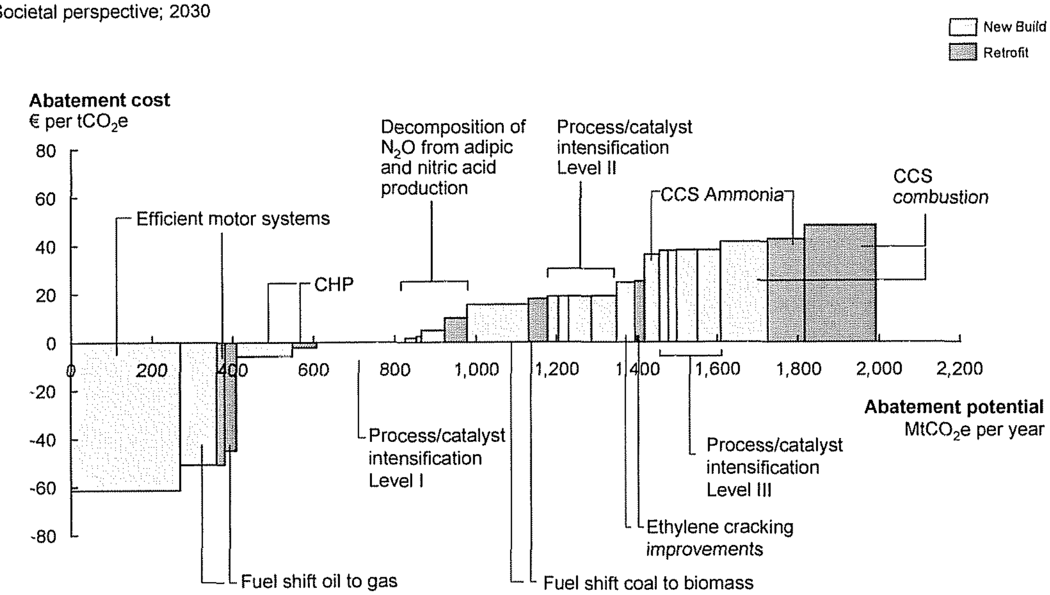
Potential abatement

The global Chemicals industry can achieve a substantial reduction in its emissions by 2030 through concerted abatement efforts. While some of the measures we have identified will be net-profit-positive (and will at least partially occur as part of the BAU case), other steps will require a considerable financial and technological effort.

Exhibit 8.5.1

Global GHG abatement cost curve for the Chemicals sector

Societal perspective; 2030



Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €60 per tCO_2e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play.
Source: Global GHG Abatement Cost Curve v2.0

We have identified 30 abatement measures that we can group in four categories (Exhibit 8.5.1):

A. **Energy efficiency.** At about 1,100 $MtCO_2e$, energy-efficiency measures contribute 55 percent of the total abatement potential, and are mostly net-profit-positive. Examples include motor systems, combined heat and power (CHP), ethylene-cracking improvements, and the optimization of catalysts.

B. **Fuel shift.** About 320 $MtCO_2e$, or 16 percent, of the total abatement potential, can be achieved by increasing the share of alternative, cleaner fuels, for example from oil to gas and from coal to biomass. Most of the measures in this category come at a relatively low cost or offer a net benefit to society. If fuel-shift efforts are undertaken aggressively, about 50 percent of the current use of coal can be replaced with biomass by 2030, taking total global demand and supply into account.

C. **Carbon Capture and Storage (CCS)** – CCS in the chemicals industry is estimated to account for a possible 21 percent of total abatement potential, or around 420 $MtCO_2e$). CCS is a new technology that sequesters CO_2 after it has been emitted from a point source in the production cycle through methods such as placing it in subterranean storage. Two different CCS technologies are applicable to the Chemicals sector: the capture of a pure CO_2 stream coming from ammonia production; and the capture of CO_2 from fuel-combustion emissions, similar to CCS in the Power sector.

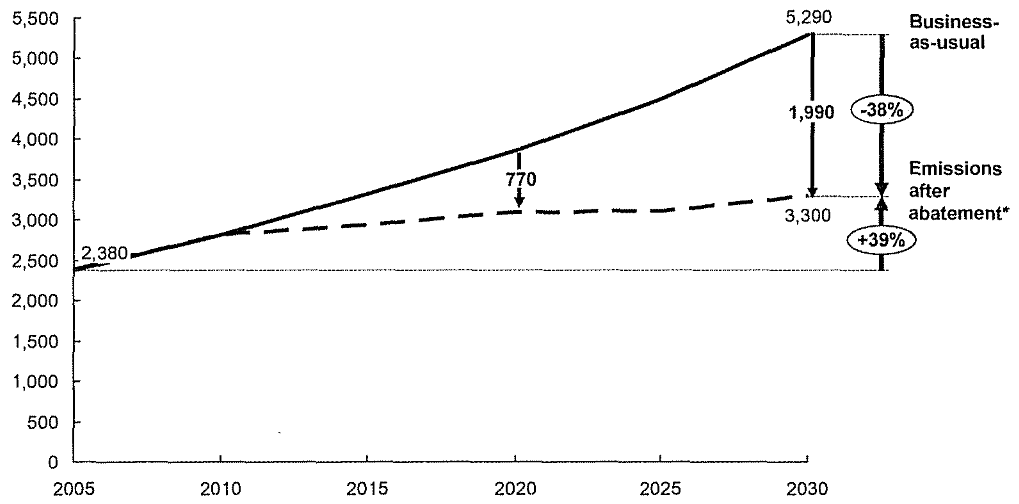
D. **Decomposition of non-CO_2 GHG gases.** The destruction of highly potent GHGs accounts for roughly 8 percent, or 150 $MtCO_2e$, of the abatement potential in the Chemicals sector. Levers in this category include the decomposition of N_2O that accrues in the production of the common chemicals nitric acid and adipic acid.

The identified abatement measures for the Chemicals sector would eliminate approximately 2.0 $GtCO_2e$ per year worldwide in 2030, a 38 percent reduction from the BAU case. However, 2030 emissions after abatement would still be 39 percent higher than in 2005, due to high production growth (Exhibit 8.5.2). The inherent energy intensity of Chemicals implies that the industry will be unable to further reduce its emissions footprint without significant technological breakthroughs in clean energy.

Exhibit 8.5.2

Emissions development for the Chemicals sector

$MtCO_2e$ per year



* Economic potential of technical measures

Note: This is an estimate of maximum economic potential of technical levers below € 60 per tCO_2e if each lever was pursued aggressively
It is not a forecast of what role different abatement measures and technologies will play

Source: Global GHG Abatement Cost Curve v2 0

A further abatement potential of possibly several hundred megatonnes CO_2e per year in 2030 could be achieved through the replacement of ODS substitutes used in refrigeration, air conditioning, and foam blowing agent application, but we have not assessed this possibility in depth in this analysis. Currently, Hydrofluorocarbons (HFCs) with global warming potentials (GWP) of over 1,000 are mostly used as ODS. However, several replacement products with GWP close to zero are being made commercially available, including, for example, automotive air conditioning and one-component foam blowing agents for insulation, which would reduce emissions dramatically.

For the abatement measures in this sector in aggregate, the cost would be negative at the outset at *minus* € 3 per tCO_2e in 2020, but would turn positive during the period of our analysis, increasing to around € 5 per tCO_2e in 2030. This increase is caused primarily by the introduction of CCS, which is a high-cost lever. There large potential overall of about 600 $MtCO_2e$ that would offer net benefits to society through fuel shift, the replacement of motor systems, and CHP. Abatement in the Chemicals sector as a whole is characterized by high upfront investments followed by large and increasing savings of operational costs. The abatement case calls for a total of € 520 billion in capital investment from 2010 to 2030. During this timeframe, operational cost savings of about € 280 billion can be realized through savings of energy, primarily fuel.

Socioeconomic view	**Average cost** (€ per tCO_2e)	**CapEx** (€ billion per year)	**OpEx** (€ billion per year)
2015	0	24	-7
2020	-3	24	-15
2025	5	29	-15
2030	5	27	-20

There are broad regional variations in carbon and energy intensity within the Chemicals industry. While China and the rest of the developing world currently show significantly higher carbon intensities than Western countries, this difference is expected to decline over time as production technologies are improved and standardized globally, and abatement levers are implemented in developing regions.

The biggest abatement potential exists in regions with higher carbon intensities. For example, about 40 percent of the total abatement potential is in China, primarily due to an expected shift to biofuels and the implementation of CCS. Investment in abatement levers in the developing world also yield a higher return than in developed countries. For instance, China represents less than 36 percent of total investment requirements for its 40 percent share of the total potential in 2030.

Implementation challenges

Some conditions must be put in place for the Chemicals sector abatement levers to succeed in reducing emissions:

- **Development and availability of alternative fuels.** Shifting from oil to gas and from coal to biomass is a key step in reducing carbon emissions. In certain regions, ensuring adequate supplies of biomass in order to replace oil as the primary fuel for production could be challenging.
- **Technology and infrastructure.** CCS is a nascent technology that has yet to be tested adequately tested for use in the chemicals industry. CCS is not expected to be rolled out until 2020.

8.6 Transport

The Transport sector consists of four subsectors: road, sea, air, and rail transport. Road is the largest subsector in size (accounting for 71 percent of GHG emissions in 2005) and, as a result, we have conducted a detailed bottom-up analysis of this subsector. Sea (17 percent) and air (10 percent) are the next biggest subsectors. For both of these subsectors, we have estimated abatement potential and costs based on a set of individual measures in a top-down approach. Given the small size of rail emissions (2 percent) and the relative efficiency of this subsector compared with others, we do not cover this subsector in this analysis.

ROAD TRANSPORT

The Road Transport sector emits 5.0 $GtCO_2e$ per year, contributing 12 percent of global emissions of GHGs in 2005. Around 60 percent of global road transport emissions currently originate from North America and Western Europe. In the absence of abatement measures, emissions from the road transport sector are projected to increase to 9.2 $GtCO_2e$ per year in 2030, mainly driven by an annual increase in vehicles of around 7 percent in the developing world. With new car sales in 2030 incorporating a combination of all currently known abatement measures, total fleet emissions can be lowered by about 30 percent, stabilizing at 2016–2020 levels. Most of the abatement potential derives from the use of existing technologies to make internal combustion engine-based vehicles more fuel-efficient. In addition, biofuels, hybrid vehicles, and electric vehicles also play an important role in emissions abatement. On average, abatement is net-profit-positive to society as fuel savings overcompensate for initial investments.

The Road Transport sector comprises all GHG emissions "well-to-wheel", including emissions related to the production of fuel ("well-to-tank") and fuel combustion emissions ("tank-to-wheel"). Total emissions in 2005 were 5.0 $GtCO_2e$ per year, of which 4.4 $GtCO_2e$ were emissions from combustion.

This analysis segments road vehicles into three types:[60]

- **Light-duty vehicles (LDVs)**, i.e., passenger cars and commercial vehicles of up to 3.5 metric tonnes, totaling 728 million vehicles worldwide and emitting 2.7 $GtCO_2e$ per year in 2005, or 257 g CO_2 per km (tank-to-wheel, real figures for fleet).

60 We exclude buses and two/three-wheel vehicles from the analysis because of minimal global shares of emissions.

- **Medium-duty vehicles (MDVs)**, defined as trucks with 3.5–16 metric tonnes in weight (e.g., delivery trucks), totaling 38 million vehicles emitting 0.7 $GtCO_2e$ per year in 2005.
- **Heavy-duty vehicles (HDVs)**, defined as trucks greater than 16 metric tonnes in weight (e.g., long-haul freight trucks), totaling 20 million vehicles emitting 1.0 $GtCO_2e$ per year in 2005.

Road transport is characterized by numerous mobile sources of emissions. Light-duty vehicles are largely privately owned, while medium- and heavy-duty vehicles are usually owned by commercial enterprises. Vehicles from all segments potentially can use different fuel types, such as gasoline, diesel, biofuels, electricity, or various fuel mixes.

Two-thirds of global road transport emissions currently come from developed countries, which accounted for 76 percent of LDVs in 2005. The United States has the largest vehicle fleet by far at 220 million LDVs (30 percent of the worldwide total), 3.5 million MDVs, and 4 million HDVs (20 percent of the total).

Emissions intensity varies greatly among regions. At 40 and 30 percent, respectively, Africa and North America have the highest average carbon intensity per km travelled, exceeding some European countries.

Business-as-usual emissions

The BAU case (i.e., without abatement of emissions) for the Road Transport sector shows emissions growing by 83 percent overall through 2030, reaching 9.2 $GtCO_2e$ per year (8.1 from tank-to-wheel emissions). The BAU case includes only powertrain technologies already available in the marketplace. Minor fuel-economy improvements are included in the BAU case, as older vehicles in the fleet are retired and replaced. The BAU case includes an increased share of bioethanol and biodiesel in the global fuel mix after 2010, based on fulfilling existing legislative mandates.[61]

BAU growth through 2030 is driven by an increased number of vehicles, resulting in a higher total distance travelled, especially in the developing world and by commercial vehicles. The number of LDVs globally will nearly double, and the number of MDVs and HDVs will more than double:

- **LDVs** – 1,321 million vehicles worldwide emitting 4.3 $GtCO_2e$ (tank-to-wheel) per year in 2030.
- **MDVs** – 97 million vehicles emitting 1.5 $GtCO_2e$ per year.
- **HDVs** – 45 million vehicles emitting 2.3 $GtCO_2e$ per year.

Annual kilometers travelled worldwide will increase by 78 percent for LDVs, 166 percent for MDVs, and 117 percent for HDVs in 2005–2030.[62] Nearly all of this expansion will be driven by growth in the vehicle fleet, since average distance travelled per vehicle is forecast to increase by less than 10 percent by 2030. Slightly more than half of vehicles will be used in the developing world in 2030. China is forecast to have the world's largest vehicle fleet in 2030 at 285 million LDVs (22 percent of the worldwide total), 37 million MDVs (38 percent of total), and 10 million HDVs (21 percent of total), thus overtaking the United States.

61 BAU case biofuels feedstock is limited to first-generation agricultural feedstock (grain ethanol, sugarcane ethanol, palm diesel, rape seed diesel and soy diesel).

62 Assuming 2005's vehicle mix through 2030.

Road transport emissions will grow strongly in Asia; China accounts for almost half of the total emission growth through 2030, while India accounts for another 14 percent. Emissions from North America and Europe will remain relatively stable, with annual growth of only 1.2 percent. Because of its large emissions base in 2005, the United States will continue to represent a large proportion of total emissions. The United States and China together will account for 47 percent of 2030 emissions.

The BAU case is based on data from proprietary McKinsey automotive research, the International Energy Agency/World Business Council of Sustainable Development, the California Environmental Protection Agency, and comprehensive industry expert discussions.

Potential abatement

We can divide technical abatement levers in Road Transport into five groups:

A. Conventional internal-combustion engine (ICE) improvements. The fuel efficiency of internal-combustion engines, whether spark (gasoline) or compression (diesel) ignition, can be significantly enhanced through technical enhancements made to both powertrain (e.g., downsizing and turbo-charging) and non-powertrain systems (e.g., vehicle-weight reduction). Those improvements will drive most change on a per-car basis. The overall fuel-efficiency benefit is calculated using a combination of improvements, taking into account some cross-measure cannibalization. Powertrain measures for gasoline LDVs include variable valve control (about an 8 percent fuel-efficiency gain), strong engine friction reduction (around 4 percent gain), strong downsizing (some 12 percent gain), and homogeneous direct injection (approximately a 4 percent gain). Non-powertrain measures for gasoline LDVs include low rolling resistance tires (around 2 percent gain), tire pressure control system (about a 1 percent gain), strong weight reduction (approximately a 6 percent gain), pump and steering electrification (about a 3 percent gain), air conditioning modification (about a 2 percent gain), optimized transmission/dual clutch (around a 6 percent gain), improved aerodynamics (a gain of approximately 1 to 2 percent) and start-stop system with regenerative braking (6 percent gain). Diesel ICE measures are similar.

For MDVs and HDVs, we define bundles in a similar manner. Measures include varying degrees of rolling-friction reduction (around a 3 percent gain), aerodynamic improvements (a gain of some 1 percent), and conventional ICE improvements such as mild hybrid powertrains (approximately a 7 percent gain). Commercial vehicles are further along the learning curve of fuel consumption since fuel spending is of substantially higher importance than for LDVs; therefore the relative improvement potential is lower.

The calculations in this study only take into account technical measures that are already widely known to experts, and where there is a substantial likelihood of significant adoption. By definition, this eliminates consideration of "game changing" new technologies that could drive substantial abatement or accelerate fleet changeover. While we do not consider these factors in this particular estimate, we do believe that the chances of such discontinuity are significant and should be considered by all stakeholders when evaluating long-term abatement potential.

B. Hybrid vehicles. Hybrid electric vehicles take many forms. Hybrids on the road today range from mild, simply incorporating some form of a stop-start system, to full, where an electrical drive system is packaged in parallel to the ICE drive system and is calibrated to run when conditions best suit electrical driving. In addition, full hybrids are typically engineered in such a way that aerodynamic drag, rolling resistance, and weight are all reduced to varying degrees. The full hybrid battery is charged by the drive cycle of the vehicle (e.g., regenerative braking).

A further hybrid development will be the introduction of "plug-in hybrids", i.e., full-hybrids that can be recharged both by the vehicle-driving cycle and by external sources, enabling the vehicle to run more frequently on electrical power. Vehicle emissions may well be reduced with such a vehicle compared to an equivalently sized ICE or full hybrid, but total carbon emissions will depend on the CO_2e intensity of the electricity drawn from the grid. Consequently, electrified vehicles will save gasoline, but substantial reduction of carbon emissions can only be achieved with substantial changes in the power mix.

For both types of hybrids, the abatement potential will be based on the share of electric driving dictated by the vehicle's drive cycle (e.g., rural versus urban) and opportunities to recharge (in the case of a plug-in hybrid). One critical assumption for plug-in hybrids is that the owner will not need to replace the battery during the lifetime of the vehicle. Plug-in hybrids must handle both full charging cycles when an almost empty battery is connected to the grid, and micro cycles when the battery receives energy from the brakes while driving. While batteries today are believed to already handle enough full charging cycles that last longer than a normal vehicle, the impact of micro cycles on battery lifetime is not fully understood.

C. **Electric vehicles.** Despite being very much in their infancy in terms of market penetration, range-worthy (battery) electric vehicles (EVs) are gathering significant momentum as battery innovators develop the nanotechnology and chemistry that will be required to create the energy density needed to give these vehicles the range desired by consumers. EVs are powered by an electric motor that receives power, via a controller, from a battery of significant capacity. Much progress is anticipated in terms of cost, energy density, and charging infrastructure, making EVs feasible in terms of cost and consumer convenience and significantly enhancing the opportunity for EVs to become mainstream. The abatement potential from EVs depends on the CO_2e intensity of electricity drawn from the grid.[63] In the outlook for 2050, with an even greener power mix, strongly electrified vehicles may play a very important role in achieving a step change in the reduction of transport emissions.

D. **Compressed natural gas (CNG) vehicles.** These vehicles run on an ICE (fairly similar to gasoline and diesel engines) fueled by CNG. The abatement potential originates from the lower CO_2e intensity of natural gas compared to other fossil fuels. However, long-distance pipelines for sourcing natural gas can potentially offset the CO_2e advantage.

E. **Biofuels.** Fossil fuels can be replaced by first-generation biofuels, such as bioethanol (from food feedstock), biodiesel (from vegetarian oils) and biogas, or by second-generation biofuels based on lignocellulosic biomass (e.g., lignocellulosic (LC) ethanol, Fischer-Tropf (FT) diesel, and dimethyl ether (DME)). The abatement potential varies depending on the biomass used for biofuel production (with respect to agricultural and process emissions), and on the potential for land-use change emissions associated with increased crop production.

- ***First generation biofuels.*** The most prevalent first generation biofuel today is bioethanol. It can be derived from various feedstocks such as corn, wheat and sugarcane, with sugarcane being by far the best first-generation bioethanol option in terms of cost and GHG reduction. First-generation biodiesel is derived from oil crops such as palm oil, rapeseed, soy beans, and recycled waste oils and fats. These first-generation products do provide abatement opportunities. However, they will have to have been produced from sustainable feedstock and produced in a way to avoid land-use change or displacement of other products into unsustainable production, e.g. via yield increases or using "idle land" (see fact box Biofuels).

63 Calculations assume the emissions intensity of the power mix after abatement.

Biogas is another option that can be a promising biofuel; however scalability at competitive cost appears limited.

- ***Second-generation biofuels.*** Second-generation bioethanol is derived from lignocellulosic feedstock such as bagasse, wheat straw, corn stover, or dedicated energy plants such as switch grass, and have a CO_2 reduction potential of up to 90 percent. Although not commercially viable today, significant research and development efforts could bring production costs down to a competitive level. Second-generation biodiesel can be derived from various other feedstocks, including wood, energy crops such as switchgrass, and algae. Biofuels from these feedstocks are likely to coexist by 2030. Second-generation biofuels may also include syngas-derived DME or FT gasoline and diesel. Given regional differences in demand for, and government support of, gasoline and diesel substitutes, technologies targeting either fuel are expected to emerge.

Biofuels – some upsides and potential downsides

Upside. Algae are a promising feedstock, which could grow in areas that do not compete with food or fresh water. To date, commercial algae production has focused on niche markets such as nutraceuticals and therefore technological development for commodity fuels markets is in its infancy. This current uncertainty is believed to be too high to warrant inclusion in the cost curve. However, if the required developments were to be realized, the potential upside would be very large and algae could pick up a significant share of the transportation fuel pool. The promise of a large volume of low-cost algae bio-diesel has already triggered intense research efforts.

Potential downside. Land-use change caused CO_2 emissions can have strong adverse effects on the sustainability of biofuels. As production volumes of biofuels expand, it will be key to implement standards and regulations that ensure that land is used in a sustainable manner. Besides direct land-use change, indirect land-use change also needs to be considered. Policies should be based on globally consistent methodologies for assessing impacts and should encourage production that minimize negative *direct* land use change effects and hence negate the possibility of indirect impacts. Such practices include yield intensification or the use of marginal land.

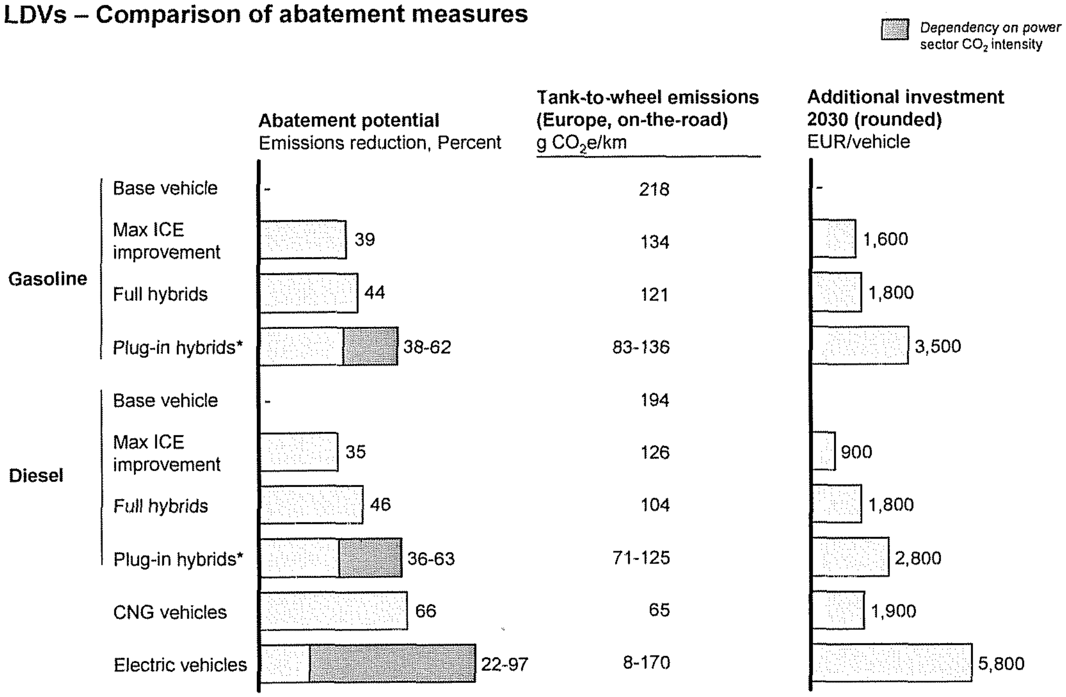
Beyond these five groups of abatement levers, hydrogen vehicles are a nascent technology that could prove an alternative solution. Based on current knowledge, the abatement cost is extremely high and for this reason hydrogen vehicles have not been considered in the cost curve.

In addition to the "known" technologies that have been considered for abatement calculations, there will undoubtedly be a number of breakthrough innovations that will not only further optimize what we know today, but will also advance the art of combustion and propulsion. In that light, our abatement scenarios may prove, in the long run, to be conservative. The automotive crystal ball is usually populated with more incremental developments than it is quantum shifts in technology, thanks in part to an industry that is risk-averse especially in terms of safety, quality, and cost. That said, significant investment is being deployed into the development of "clean-tech" solutions for automobiles as stiffer emissions-regulation looms, gasoline prices become increasingly volatile, and fuel economy becomes more of a reason for consumers to consider a vehicle.

All the powertrain and non-powertrain improvements come at an initial cost, and they lead in turn to substantial savings on fuel spending. For LDVs, the cost and emissions reduction potential of these levers are shown in Exhibit 8.6.1. The additional cost is relative to the cost of a "base vehicle" which

Exhibit 8.6.1

LDVs – Comparison of abatement measures



* Assuming 66% electric share for Plug-in Hybrids
Source: Global GHG Abatement Cost Curve v2 0

is assumed to have a median or "typical traditional" powertrain for gasoline and diesel. For gasoline vehicles, which globally represent the vast majority of LDVs, a fuel consumption reduction of about 39 percent is possible with pure ICE improvements at an incremental cost of 10 percent of the vehicle base price. Full hybrids (including non-powertrain measures such as weight reduction) cost about 22 percent more than maximum ICE improvements, and can achieve a further 5 percentage points of fuel reduction. Substantially higher emission reductions of almost 100 percent are made possible by switching to plug-in hybrids and pure electric vehicles (if the local power sector has a very low emission intensity), at a substantially higher cost (of an additional 120 to 260 percent).

For biofuels, no extra cost to the vehicle is assumed, but there is a different cost structure and carbon-emission pattern of the fuel itself compared with fossil fuels.

Scenario analysis. The total road transport abatement opportunities are assessed using different scenarios, in a similar way to our analysis of the Power sector. The Road Transport sector exhibits a higher level of uncertainty than most other sectors for technology development and related cost, regulation, and consumer behavior and preferences. To develop scenarios, we applied different penetration shares of abatement options (ICE improvements, hybrids, electric, and CNG vehicles) for LDVs over time. These different penetration rates are used solely to illustrate the range of abatement potential and should not be considered a forecast or an endorsement of a specific technology. As an exception, the scenarios do consider levers with a cost in 2030 of below € 100 per tCO_2e, given the explicit knowledge of these technologies and the substantially higher regional cost range in the Transport sector. Biofuels are not affected by the scenario choices, as their potential is fully included in each scenario.

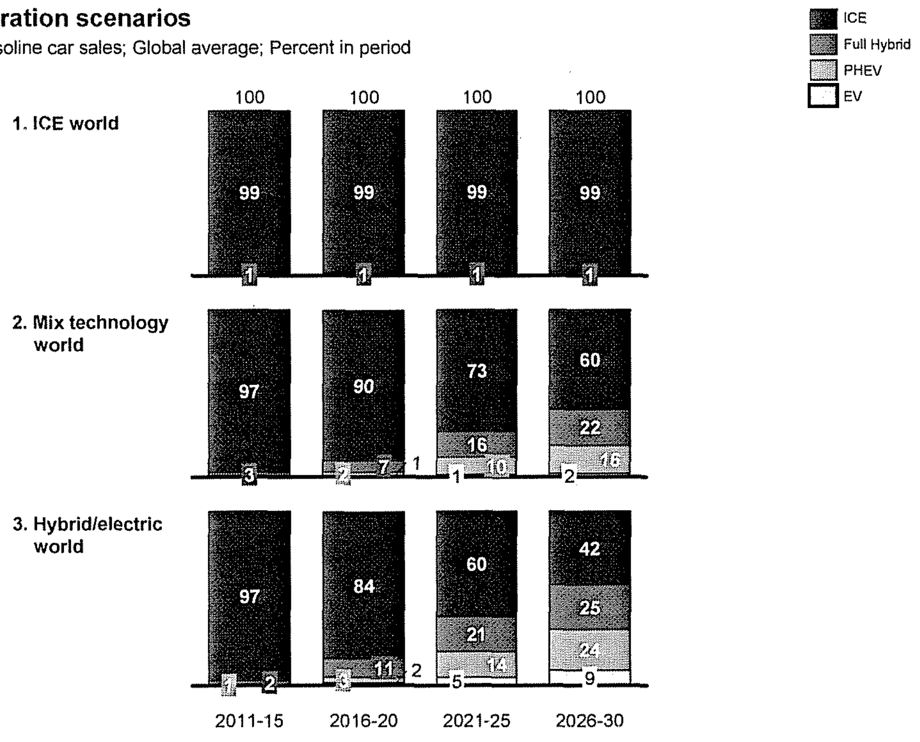
- **Scenario 1 – ICE World.** In this scenario, all new cars are ICE cars throughout the entire period. ICE improvement measures are implemented gradually, with all new cars equipped with the highest-efficiency measures starting in 2026.
- **Scenario 2 – Mix Technology World.** The vehicle-sales mix shifts from 90 percent ICE engines and 10 percent "other powertrains" in 2016–2020 to 40 percent "other powertrains" in the 2026–2030 period. In 2026–2030, full hybrids account for 22 percent of new sales and plug-in hybrids for 16 percent. In this scenario, electric vehicles are to replace 2 percent of gasoline vehicles. The penetration of new powertrains is based on consensus estimates.
- **Scenario 3 – Hybrid/Electric World.** The portion of hybrids and EVs in the sales mix ramps up from 16 percent in 2016–2020 to 58 percent in 2026–2030. In the final portion of the study period, 25 percent of sales are full hybrids, 24 percent are plug-in hybrids, and 9 percent are EVs. These rates represent expert expectations on maximum technical ramp-up potential for new powertrains.

The main uncertainty between the scenarios lies within the abatement-potential development for LDVs. Thus, the various scenarios reflect different penetrations for LDVs. All scenarios are designed to have a very high abatement potential. The mix of powertrains is the key difference (Exhibit 8.6.2). The shares of gasoline and diesel vehicles are held constant in each region, and penetration shares for new powertrains for diesel vehicles are similar to those of gasoline vehicles.

Exhibit 8.6.2

LDV – penetration scenarios

Share of new gasoline car sales; Global average; Percent in period



Source: Global GHG Abatement Cost Curve v2 0

MDV and HDV penetration rates are the same in all scenarios. Starting in 2016, almost all new MDVs and HDVs will either have improved ICE powertrains – including reduced rolling friction and mild hybrid features – or be hybrid vehicles. Even in the BAU case, a significant share of commercial vehicles are equipped with some fuel- reduction bundles, due to the increased importance of fuel costs as a buying-decision criterion when compared with passenger cars. MDV/HDV full hybrids and plug-in hybrids both exhibit an abatement cost that is significantly above the cost-curve cut-off, and have therefore not been included in this analysis. This is true also for niche MDV segments, such as waste-collection vehicles where driving patterns and extra equipment mean that hybrid technologies would be able to significant improve fuel economy. Unfortunately, the configurations that would exhibit the highest fuel-economy improvements typically also require additional investments on top of the "basic" hybrid equipment. Buses are outside the scope of the analysis, but there seems to be significant potential for fuel-economy improvement for a full-hybrid city bus, since it would be a showcase application for a start-stop system with regenerative braking. This could lead to an abatement cost of below €100 per tCO_2e.

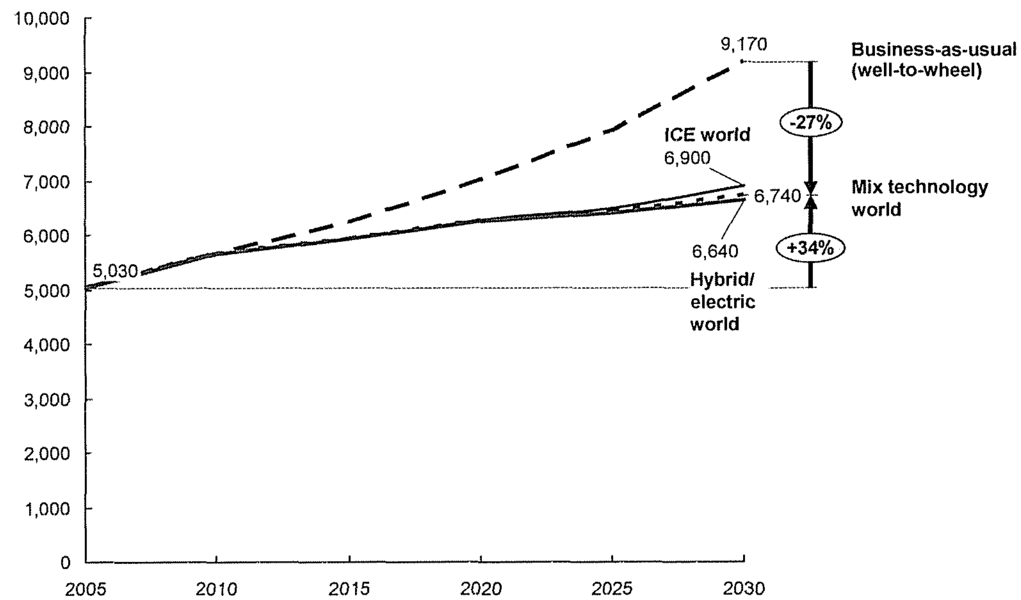
The three road transport scenarios lead to a 2030 abatement potential ranging from 25 to 28 percent (2.3 $GtCO_2e$ to 2.5 $GtCO_2e$ per year) for all vehicle types combined (Exhibit 8.6.3). For LDVs specifically, the ICE World scenario would lead to a 29 percent reduction in emissions (1.4 $GtCO_2e$ per year); the Mix Technology World offers a 33 percent reduction (1.6 $GtCO_2e$ per year); and 35 percent abatement (1.7 $GtCO_2e$ per year) can be achieved in the Hybrid/Electric World scenario. In all three scenarios, emissions for MDVs can be reduced by 8 percent from the BAU case, and by 9 percent in the case of HDVs. These abatement figures are lower than for LDVs, primarily because the possible further fuel-consumption reductions of ICE measures are substantially lower than for LDVs. Compared with 2005 levels (including refining emissions), emissions would increase by around 20 to 30 percent in all scenarios, driven by the significant growth of total distance travelled.

The biggest abatement potential is found in regions with the highest BAU case emissions, as one would expect. The United States and China account for the largest abatement potential, with 53 percent of total global emissions savings. After abatement, the United States and China together still account for 49 percent of emissions.

Exhibit 8.6.3

Emissions development for the Road Transport sector

$MtCO_2e$ per year



* Economic potential of technical measures

Note: This is an estimate of maximum economic potential of technical levers below € 60 per tCO_2e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play

Source: Global GHG Abatement Cost Curve v2 0

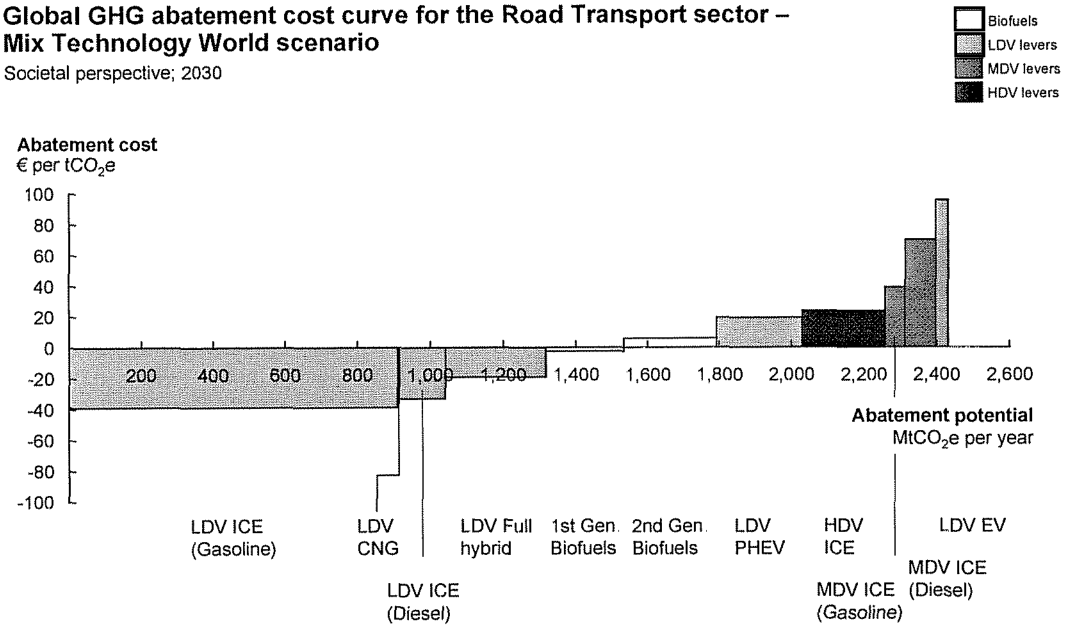
When comparing average cost of the scenarios, the range is minus € 17 to minus € 3 per tCO_2e for all measures. For LDVs only, the ICE World scenario would cost on average minus € 38 per tCO_2e, the Mix Technology World minus € 24 per tCO_2e, and Hybrid/Electric World minus € 13 per tCO_2e.

To illustrate the effects of the individual lever categories, we show the cost curve for the Mix Technology World scenario in Exhibit 8.6.4. The cost for a specific lever is the cost compared with the BAU case, i.e., what the abatement cost would be to replace a median 2005 vehicle with a new vehicle as specified.

Exhibit 8.6.4

Global GHG abatement cost curve for the Road Transport sector – Mix Technology World scenario

Societal perspective; 2030



Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €100 per tCO_2e in a penetration scenario if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play

Source: Global GHG Abatement Cost Curve v2.0

Most abatement levers, particularly those concerning conventional ICE improvements, come at a benefit to society – i.e., there is a positive payback over the lifetime of a vehicle when subtracting fuel-cost savings from the initial additional investment into more emission-efficient vehicle technology. The cost curve shows that the majority (60 percent) of LDV abatement, excluding biofuels effects, can be achieved with technical improvements to ICE vehicles for fuel efficiency. Gasoline fuel efficiency bundles for LDVs have an abatement potential of 0.9 $GtCO_2e$ per year. Similarly, the diesel-efficiency bundles for LDVs show a 0.1 $GtCO_2e$ per year abatement potential. In this scenario, full hybrids account for 0.3 $GtCO_2e$ per year abatement potential, plug-in hybrids for 0.2 $GtCO_2e$ per year, and electric vehicles for 0.03 $GtCO_2e$ per year. Given a reasonably clean power mix, plug-in hybrids and EVs have substantially higher emission-reduction potential per vehicle than hybrids or ICE improvements. As further emission reductions beyond 2030 are required, these technologies will likely be needed to achieve the targets.

Biofuels to replace gasoline have substantial abatement potential. First- and second-generation biofuels account for around 20 percent of total abatement in 2030. For modeling purposes, ethanol was chosen to represent biofuels. First-generation bioethanol are modeled on sugarcane, since other crops are not expected to offer cost-effective abatement opportunities. Second-generation LC ethanol is modeled on a weighted average of feedstock. The BAU case includes 38 billion liters of biodiesel production; there is no additional biodiesel in the abatement case.

As we have discussed, there are several interesting options that we have not modeled, most notably second-generation biodiesel from algae and gasification-based diesel substitutes. The share of the gasoline-equivalent fuel mix is assumed to increase to 25 percent of energy content through 2030. This (ambitious) level was chosen as a technical limit for 2030; it corresponds to the current ethanol concentration in Brazilian gasoline (all regular Brazilian cars can run on this mix) and annual growth of about 15 percent in biofuel production.

Taking the Mix Technology World scenario as illustration, the total investment for road transport abatement levers in 2011–2030 is approximately € 3,050 billion, which is partly offset by savings in operating expenditures of approximately € 1,870 billion in the same period. Investments jump in the 2016–2020 period – all ICE measures are rolled out only then due to OEM lead times. Due to the fact that new vehicle sales and the highest penetration of new powertrain concepts occur in this period, investments peak in the 2026–2030 period at € 270 billion annually.

Socioeconomic view	**Average cost** (€ per tCO_2e)	**CapEx** (€ billion per year)	**OpEx** (€ billion per year)
2015	10	33	-12
2020	4	107	-53
2025	-3	202	-119
2030	-10	269	-190

Abatement opportunities beyond technical vehicle improvements. Beyond ICE improvements, hybrid vehicles, electric vehicles, and biofuels, there are several abatement opportunities that require no technical change in vehicles but rather action by individuals, companies, or governments. We can group these into three categories:

- ***Behavioral changes by LDV consumers.*** First, consumers can choose to buy smaller cars or cars with smaller engines and consequently lower fuel consumption. Second, they can change driving behavior to a more fuel-efficient style, i.e., reducing maximum speeds (since fuel consumption grows exponentially with speed), reducing fast accelerations, and avoiding unnecessary braking. Technical support for "eco-driving" exists, for example in the form of eco-lamp indicators as well as eco-driving training, which can increase drivers' awareness. Third, driving less is a consumer choice. Alternative ways of transport (by foot, bicycle, or public transport) can be an option in many cases, as can car pooling.
- **Commercial transport improvements (MDVs, HDVs).** Emissions can be reduced through increased vehicle capacity, i.e., longer trucks, and increased utilization by better utilization planning. As illustration, if a segment of the long-haul general cargo HDV fleet were gradually replaced by longer trucks with a 50 percent higher load capacity (two vehicles replacing three), the abatement potential would be around 15 percent of emissions for that segment—in itself the same potential as all HDV ICE improvements together. If 35 percent of the global long-haul general cargo HDV fleet (long-haul general cargo assumed to account for 45 percent of all HDVs) were to be replaced, the abatement opportunity would be about 50 $MtCO_2e$ per year in 2030. Improved route planning, supported by IT systems, can help reduce distance driven. Choosing

the appropriate vehicles and engines for the commercial tasks would avoid "oversizing" of vehicles, leading to fewer emitting vehicles. Proper maintenance of vehicles would also have a positive effect on emissions and operating cost.

- **Traffic-system improvements for all vehicle types.** Governmental organizations have a wide range of options for influencing emission reductions. Intelligent transportation systems, such as Japan's Vehicle Information and Communication (VICS) System, improve traffic flow. Similarly, road design and construction has a substantial effect. Examples include improved crossing design, separate lanes for commercial vehicles, and electronic toll collection (ETC). Promoting modal shift from car to public transport and from road to rail for commercial purposes would boost emissions reductions. Especially in the developing world, where there are strong urbanization trends, urban planning with well-designed public transport has high potential. Lastly, regulatory levers such as lowering speed limits and introducing congestion charges (e.g., in London), can be introduced to achieve emissions reductions.

Implementation challenges

To achieve success in abating road transport emissions, both economic and technical challenges need to be addressed:

- **Consumer preferences and non-rational economics.** Many factors influence the decision to buy a new car, including driving performance, design, and durability. Fuel consumption, and consequently emissions, is only one dimension for consumers when comparing vehicles. In addition, consumers usually do not thoroughly calculate and compare the economics of different vehicles when making their purchasing decisions. When they do so, they often overestimate the upfront investment compared to later savings.
- **Principal-agent problem.** Especially for light-duty vehicles, a gap exists between the socioeconomic perspective, the perspective of the individual vehicle buyer, and the OEM. Given the non-rational economics of the consumer, it is not clear to OEMs that buyers would be willing to pay the extra price for fuel-savings bundles, even when the consumer has the benefits. Therefore, these fuel-reduction options may not be implemented or offered.
- **Technology advancement.** Battery capacity and cost are the key factors limiting broad use of hybrid and full electric vehicles. Current technology restricts the range and speed of vehicles running on batteries and electric motors.

AIR AND SEA TRANSPORT

Both Air Transport and Sea Transport are global sectors with the vast majority of emissions occurring in international territories. For this reason, we do not divide and attribute emissions to separate countries in this analysis (in accordance with established practice). Given their relatively small size, this study analyzed both sectors in a top-down manner for total emissions potential, cost, and investment, rather than a detailed bottom-up, lever-by-lever assessment.

Air Transport. Air Transport accounted for 0.7 $GtCO_2e$ per year emissions in 2005. Emissions are expected to grow by about 3 percent per annum to 1.5 $GtCO_2e$ per year in 2030. Ongoing efficiency improvements in fuel consumption mean that emissions will grow more slowly than air traffic, which is expected to increase by 5 percent annually. Measures costing less than € 60 per tCO_2e have an abatement potential of 0.36 $GtCO_2e$ per year, or 24 percent, in 2030, and can be grouped into three categories:

- **Technology solutions including alternative fuels.** These abatement measures comprise aerodynamic improvements, engine retrofit and upgrades, accelerated fleet replacement, and reduced speed design. Alternative fuels considered are biofuels, gas to liquid, and, to a lesser extent, hydrogen, which is not expected to be commercially available before 2050. These measures come at a medium to high cost on top of the BAU case improvements and account for about 50 percent of the total sector potential for emissions abatement.
- **Operations-efficiency improvements.** This category includes improved fuel management, optimized take-off and landing procedures, taxiing with shut-off engines, cabin-weight reductions, and increased load factors. Taken together, some 35 percent of the sector's potential can be attributed to operational savings for this category, which can be achieved at low to medium cost.
- **Infrastructure and air-traffic management.** Air-traffic management, redesigned airspace, the flexible use of military airspace, and improved flight tracks account for about 15 percent of the sector potential and are net-profit-positive or low cost.

Since substantial efficiency improvements are already captured in the BAU case, the total abatement cost for the Air Transport sector is positive throughout the entire study period, falling slightly from € 16 per tCO_2e in 2015 to € 13 per tCO_2e in 2030, mainly because of increasing fuel costs. The required investments are € 21 billion per year in 2030 and about € 280 billion over the entire 2010–2030 period in order to capture the full abatement potential.

Sea Transport. The Sea Transport sector is forecast to emit 1.8 $GtCO_2e$ per year in 2030, with emissions growing by 2 percent a year from the 2005 level of 1.1 $GtCO_2e$ per year. Global sea transport is expected to grow at a higher rate of 3 percent annually. The difference is explained by more efficient hydrodynamics and machinery and an expected improvement in the load factor of ships.

A further emissions reduction of 24 percent, or 0.43 $GtCO_2e$ per year, can be achieved in 2030 through the implementation of two types of measures:

- **Technology solutions including alternative fuels.** Improved hydrodynamics levers comprise optimized hull shape, tailor-made propeller design, coating systems, and stern flaps. Machinery improvements include engine optimization and upgrades, waste-heat recovery, and a plant concept with multiple engines. Alternative fuels – marine diesel oil and biofuels – are viable ways to replace bunker fuels.
- **Operations-efficiency improvements.** This category includes increased vessel size and speed reductions, which increase ships' load factor.

Further measures on the horizon, including sky sails and semi-submerged ships that use ocean currents to power intercontinental transports, are excluded from this analysis.
In contrast to the Air Transport sector, emissions abatement in Sea Transport is net-profit-positive, given a lower efficiency starting position. In 2015, the cost will be *minus* € 5 per tCO_2e, which will further decrease to *minus* € 7 per tCO_2e due to increasing fuel prices. About € 160 billion in investments is necessary in 2010–2030 to realize all abatement. Annual investments in 2030 are around € 10 billion.

8.7 Buildings

Buildings emitted 8.3 $GtCO_2e$ per year in 2005, accounting for about 18 percent of global GHG emissions and accounting for more than 30 percent of emissions in many developed nations. In the absence of abatement measures, global emissions from buildings are forecast to grow by 1.7 percent annually, increasing by 53 percent overall in 2005–2030. Carbon emissions in the Buildings sector can be substantially reduced, either with net economic benefits or at low cost, using a range of proven technologies centered on demand reduction and energy efficiency. Identified abatement measures would lower projected emissions in 2030 from 12.6 $GtCO_2e$ per year to 9.1 $GtCO_2e$ per year, with most developed countries reducing emissions to levels lower than those that prevailed in 2005. Currently, many of the abatement opportunities with net economic benefits are not realized due to misaligned incentives, high perceived consumer discount rates, information gaps, and program costs.

Energy usage in residential and commercial buildings is responsible for significant CO_2 emissions through a number of end uses: heating, ventilation, and air conditioning (HVAC); water heating; lighting; and appliances. Direct emissions from primary energy usage in buildings accounted for 3.5 $GtCO_2e$ per year in 2005, approximately 8 percent of global GHG emissions. Indirect emissions from buildings' power usage and district heat totaled 4.8 $GtCO_2e$ per year in 2005, or 10 percent of the global total.

Residential buildings, which include single-family homes and apartment buildings, account for 62 percent of the sector's overall emissions. Commercial and public buildings, which include a wide range of building types such as warehousing, food service, education, lodging, malls, and hospitals, are responsible for 38 percent of sector emissions. The overall lifespan of buildings is 35–70 years, depending on the type of building and geography, with 65–70 years being the average in developed countries. This long lifecycle leads to low or negative lifecycle costs for many abatement opportunities, but high upfront costs create a barrier to initial investments in energy efficiency. However, the long lifespan also means that decisions made during a building's construction (such as building orientation and insulation) have a strong lock-in effect for future emissions.

Business-as-usual emissions

Energy consumption and associated emissions in the Buildings sector will grow significantly from 2005 to 2030, driven by steady growth in developed countries and rapid growth in developing countries such as China and India, where GDP growth is projected to exceed 5 percent annually. Globally, total floor space will grow from 137 billion m^2 in 2005 to 240 billion m^2 in 2030, an increase of some 75 percent.[64] There will be corresponding growth in HVAC usage, along with ownership of appliances and lighting.

64 Commercial and residential floor space with modern heating.

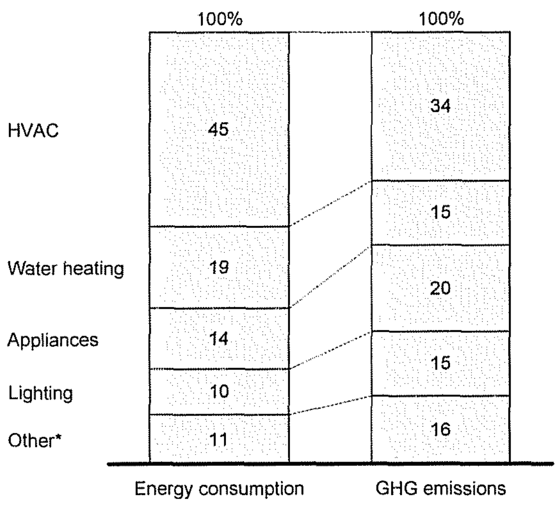
Our analysis assumes a BAU decarbonization effect in 2005–2030. For example, the share of high-efficiency gas/oil heater purchases in developed countries, at 29 percent in 2005, is expected to grow by around 2 percent annually under BAU to reach a 48 percent share by 2030. Direct and indirect emissions from buildings are expected to reach 12.6 $GtCO_2e$ per year in 2030.[65]

The analysis for technology-driven levers (e.g., appliances, lighting, and HVAC) considers items that have been proven in the market with predictable performance and cost. However, this analysis of the Buildings sector analysis excludes solar photovoltaics, which we capture in our analysis of the Power sector.

Combined heat and power (CHP) and district heating systems are also excluded as explicit abatement levers. A guiding principle in the Buildings sector analysis is to reduce overall heat and power demand through energy-efficiency levers (e.g., passive housing). Similarly, in the Power sector, the modelling approach is to maximize low-carbon solutions by using renewables, nuclear power, and CCS. After these levers are fully exploited in the Buildings and the Power sectors, our model does not show much additional abatement potential from CHP or district heating. While residential CHP is a viable interim solution to reduce emissions if favorable policy and regulatory incentives are in place, it shows limited potential in the long term when we consider the full spectrum of abatement opportunities.
The BAU case includes indirect energy because site energy alone disguises the carbon intensity of fuels. For example, HVAC accounted for 45 percent of global energy consumption in the Buildings sector in 2005 but only 34 percent of CO_2 emissions. This gap is due to the lower emissions intensity of direct fuels compared with electricity in many regions. In contrast, electricity-driven appliances and lighting account for a relatively large proportion of emissions due to the high amount of primary energy required for electricity generation (Exhibit 8.7.1).

Exhibit 8.7.1

End-use energy consumption and emissions in the Buildings sector, 2005



* *Other includes cooking* energy (such as stoves and small kitchen appliances), small devices (such as coolers and plug devices), and other mechanical / electrical equipment (such as elevators, escalators, and electronic key cards)
Source: Global GHG Abatement Cost Curve v2 0

65 Our growth assumption falls within IPCC range of scenarios for 2030, which project emissions ranging from 11.4 $GtCO_2e$ to 15.6 $GtCO_2e$ per year.

Potential abatement

We have identified 26 options for abatement in the Buildings sector, which we can group in six categories (Exhibit 8.7.2):

A. New building-efficiency packages (approximately 920 $MtCO_2e$ per year in 2030). Efficiency packages for new residential, commercial, and public buildings can reduce demand for energy consumption through improved design and orientation that take advantage of passive solar energy. The model assumes aggressive abatement measures to reach passive housing standards. Building insulation and air-tightness can be improved through use of better materials and construction of walls, roofs, floors, and windows. Furthermore, the use of high-quality mechanical ventilation with heat recovery minimizes the need for heating and cooling and ensures a high level of air quality. The "new buildings package" also assumes the use of high-efficiency water-heating technology. A new building-efficiency package for residential buildings can achieve energy consumption levels comparable to passive housing, which reduces HVAC and water heating energy consumption by up to 70 percent in developed countries, reducing site energy consumption from 115 kWh/m^2 to around 35 kWh/m^2.

B. Retrofit building envelope (about 740 $MtCO_2e$ per year). For existing residential, commercial, and public buildings, retrofit measures focused on improving building air-tightness can achieve significant reductions in heating and cooling demand. In the residential segment, we have designated two retrofit packages that include moderately aggressive assumptions. A "Level 1" retrofit of residential buildings includes weather-stripping of doors and windows; improving the air seal around baseboards, ducts, and other areas of leakage; insulation of attic and wall cavities; and the installation of basic mechanical ventilation systems to ensure air quality. These measures reduce the global average of site HVAC consumption from 70 kWh/m^2 to 54 kWh/m^2. A "Level 2" residential retrofit package is a major upgrade that could be performed in conjunction with building renovations typically occurring every 30 years or so. The Level 2 retrofit includes retrofitting windows with triple-paned models and high-efficiency glazing; adding outer wall, roof, and floor insulation; ensuring mechanical ventilation with a high level of heat recovery; and taking advantage of passive solar opportunities when these are cost-effective. These measures can further reduce site HVAC consumption to around 25 kWh/m^2.

C. HVAC for existing buildings (around 290 $MtCO_2e$ per year). For existing residential, commercial, and public buildings, HVAC systems can be replaced with high-efficiency systems when existing systems are retired. Existing gas and oil heaters should be replaced with models exceeding AFUE ratings of 95, leading to savings of around 20 percent[66]. Similarly, air-conditioning (AC) units could be replaced with models rated 16 SEER or above.[67] In appropriate climates, electric furnaces can be replaced with high-efficiency electric heat pumps, which would yield savings of 35–50 percent, depending on the climate. Improved maintenance can reduce energy consumption from HVAC and AC systems (e.g., correct level of refrigerant, regularly replaced air filters, and improved duct insulation to reduce air leakage and proper channeling of heated and cooled air). Finally, HVAC control systems in commercial and public buildings can be improved to adjust for building occupancy and minimize recooling of air. Our model includes moderate assumptions without early retirement of HVAC systems and fuel switching.

D. Water heating for existing buildings (around 350 $MtCO_2e$ per year). For existing residential, commercial, and public buildings, water heating systems can be retrofitted with high-efficiency systems. Replacing gas water heaters upon expiration of existing units with tankless or condensing

66 AFUE is annual fuel-utilization efficiency.

67 SEER is seasonal energy-efficiency ratio.

heaters would reduce energy consumption by around 30 percent, and replacement with solar water heaters could achieve savings of between 75 and 85 percent. Replacing standard electric water heaters with heat pumps upon expiration of existing units could save around 60 percent of energy use, while switching to solar water heaters could save between 65 and 80 percent. Our model includes moderate abatement assumptions in this category, without early retirement of systems and only a moderate penetration of solar-power systems in developed countries due to their high cost.

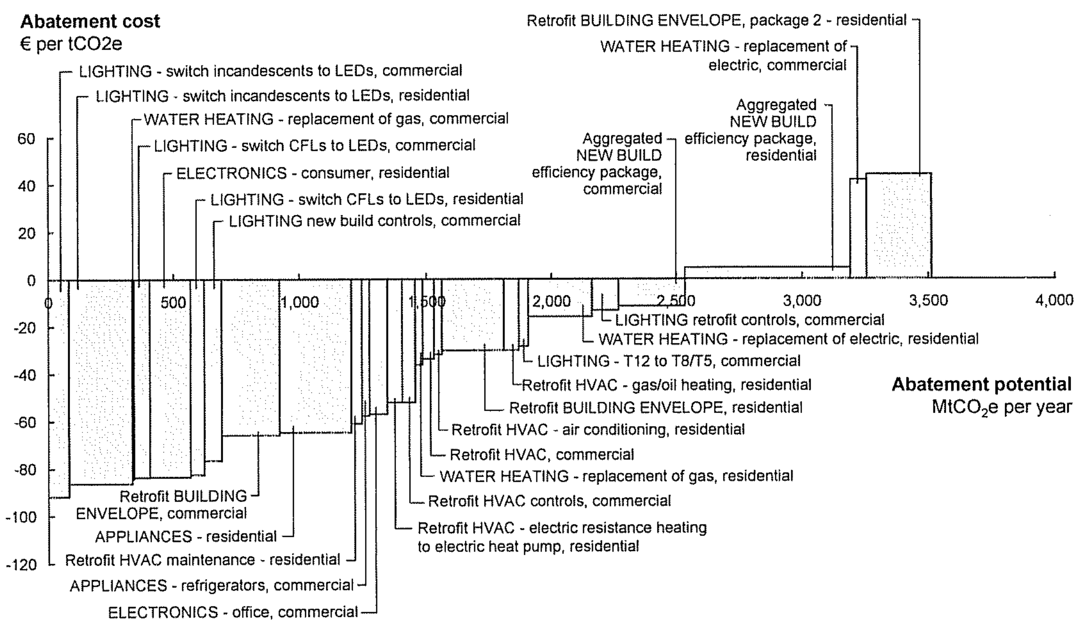
E. **Lighting (some 670 $MtCO_2e$ per year).** Existing incandescent and compact fluorescent lamp (CFL) bulbs in residential, commercial, and public buildings can be replaced with energy-efficient light-emitting diode (LED) bulbs. LEDs are estimated to provide 150 lumens per Watt (lm/Watt), compared with 60 lm/W for CFLs and 12 lm/W for incandescents.[68] In addition, existing T8 and T12 fluorescent tube bulbs in commercial and public buildings can be replaced with energy-efficient super T5s and super T8s. Lighting-control systems (controlling dimmable ballasts and photosensors to optimize light for room occupants) can be installed in new commercial and public buildings or retrofitted in existing buildings. Our model is aggressive for lighting levers, assuming nearly complete conversion to LEDs by 2030.

F. **Appliances and electronics (about 550 $MtCO_2e$ per year).** Energy-efficient electronics (e.g., consumer electronics and office electronics that reduce standby losses) can be purchased for residential, commercial, and public buildings. Energy-efficient residential appliances show 35 percent energy savings on average, with commercial refrigerators and freezers offering the potential of 15–20 percent savings. Our modelling assumptions are moderately aggressive for appliances, assuming a high level of decarbonization due to the high penetration of energy-efficient devices in the BAU case.

Exhibit 8.7.2

Global GHG abatement cost curve for the Buildings sector

Societal perspective; 2030



Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €60 per tCO_2e if each lever was pursued aggressively It is not a forecast of what role different abatement measures and technologies will play
Source: Global GHG Abatement Cost Curve v2 0

68 An 18 percent learning rate is assumed for LED bulbs. LEDs are expected to reach 75 lm/W by 2010 and 150 lm/W by 2015

Advanced computer programs for monitoring and controlling buildings' electricity usage could yield additional energy savings and emission reductions.[69]

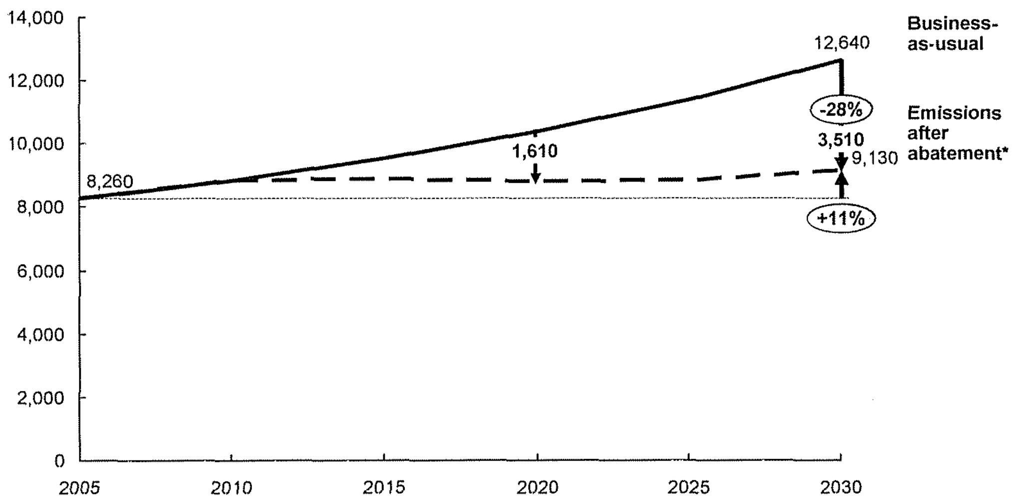
The abatement measures considered in this analysis do not assume lifestyle or behavior changes. Behavioral change from building occupants could reduce carbon emissions significantly beyond the abatement cost-curve model. The range of potential behavioral changes is broad, including reduced usage of hot water, lower home-heating temperatures, choosing homes closer to work, or even purchasing smaller homes. While behavioral changes are difficult to implement and monitor from a policy standpoint, such adjustments by building occupants could yield higher abatement potential, an issue that we address in chapter 3.

All major end-uses – HVAC, water heating, appliances, and lighting – have significant abatement potential. *The residential segment provides at 2.4 $GtCO_2e$ per year twice as much total abatement* opportunity as the commercial segment at 1.1 $GtCO_2e$ per year. This reflects the high proportion of emissions coming from the residential segment. The abatement potential of all levers grows consistently over time to 3.5 $GtCO_2e$ per year globally by 2030 (Exhibit 8.7.3), which results in emissions levels below the 2005 baseline in most developed countries.[70]

Exhibit 8.7.3

Overview of emissions pathways for the Buildings sector

$MtCO_2e$ per year



* Economic potential of technical measures

Note: This is an estimate of maximum economic potential of technical levers below € 60 per tCO_2e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play.

Source: Global GHG Abatement Cost Curve v2.0

Approximately 75 percent of the total abatement potential in the Buildings sector shows net economic benefits, with the remainder available at very low cost. Lighting options, particularly the introduction of LED bulbs, yield high net profits to society. The net economic benefits of the abatement potential in

69 These software applications are known as Energy Management Systems (EMS) and Building Management Systems (BMS).

70 The model does not include the abatement potential offered by cooking equipment and other very small appliances.

this sector overall is due to high energy savings over the full lifetime of investments. The average cost for the overall abatement potential is negative throughout the period of our analysis.

Despite the net economic benefits, new capital investments initially exceed immediate operational cost savings. Capital expenditures are projected to grow significantly through 2025 due to high requirements for purchasing initial goods. However, between 2026 and 2030, cost savings from energy efficiency will begin to outweigh new capital requirements. Operating expenditures will show immediate savings, which increase over time as energy-efficiency initiatives from earlier periods will continue to deliver energy savings.

Socioeconomic view	**Average cost** (€ per tCO_2e)	**CapEx** (€ billion per year)	**OpEx** (€ billion per year)
2015	-21	124	-24
2020	-25	169	-83
2025	-28	187	-156
2030	-32	198	-235

Geographical differences. Because of differences in climate and development levels, there is substantial variation in emissions (both current and predicted) across different geographies and regions in the Buildings sector, and therefore significant differences in opportunities for emissions abatement.

Developed countries can generally reduce energy consumption through retrofits of existing buildings and increased use of high-efficiency devices. Developing countries have an opportunity to design energy-efficient new construction, which is significant in light of building booms in several nations that are set to continue. China alone is expected to add nearly 2 billion square meters of floor space every year by 2020, and over 6 billion square meters of residential space in 2026–2030 – nearly six times the amount forecast for the United States in that period. In the United States, the relatively high cost of energy will improve the attractiveness of energy-efficient retrofits and new builds.

The abatement case shows a 25 percent reduction in emissions in China, compared with a 30 percent reduction in the United States. The two nations account for more than 40 percent of the total global abatement potential. However, even after abatement, China and the United States will remain the world's top emitters. The average reduction across all countries and regions is 28 percent, with generally higher potential for emissions abatement in colder climates as well as in those areas that currently have high energy consumption per square meter.

Implementation challenges

Much of the abatement potential in the Buildings sector would come from millions of small emitters, many of whom are individuals, rather than a limited number of large companies that are easier to influence and potentially to regulate. This fragmentation contributes to significant barriers to implementation of abatement levers:

- **Payback period.** Consumers have often been resistant to even small upfront costs, such as those required for energy-efficient appliances, if the payback period exceeds two years. Payback periods for more extensive retrofits, such as high-efficiency HVAC systems, are far longer.
- **Agency problems.** Incentives to improve buildings, whether through new builds or retrofits, are often misaligned. For example, building contractors typically will not build energy-efficient features into houses beyond minimum building-code requirements because buyers will be ultimately responsible for the operating costs of the buildings. Furthermore, builders are often constrained by upfront capital costs, which will affect a buyer's decision to purchase a building. Similarly, landlords have difficulty passing on costs of energy-efficiency improvements to tenants.
- **Visibility.** In many markets, customers do not see the real cost of power for heating, cooling, or electricity, which limits the potential for price signals to encourage changes in behavior.

These challenges have prevented energy-efficiency improvements to buildings in the past despite the high negative cost and ease of installation in many cases (e.g., lighting). Regulatory and market-based solutions are required to overcome the massive implementation challenges in the Buildings sector.[71] Technical norms and standards could be crucial in realizing the full abatement potential.

71 One example is Energy Saving Performance Contracts (ESPCs) in the United States, which help to address the upfront capital investments and monitoring issues in commercial buildings.

8.8 Waste

The Waste sector emitted 1.4 $GtCO_2e$ annually, or 3 percent of total global emissions in 2005. Without abatement measures, these emissions are projected to increase to 1.7 $GtCO_2e$ per year in 2030 as a result of an increased population and wealth worldwide. If captured, the full abatement potential in the sector would effectively eliminate waste emissions. About 60 percent of the abatement potential is achieved through recycling. While we account for this potential in the Waste sector, various industry sectors realize the abatement. The average cost for all abatement measures is negative at *minus* € 14 per tCO_2e, due to the avoidance of significant costs through the use of recycled goods in manufacturing processes and the use of mature, simple technologies for landfills. Achieving the potential abatement would require countries substantially to improve their recycling practices.

GHG emissions from waste derive mainly from solid waste and wastewater. Solid waste in landfills produces methane from the anaerobic decomposition of organic material. The main factors determining solid-waste emissions are the share of organic waste, the wetness of the system, weather conditions, and the design of the landfill. Wastewater produces methane through the anaerobic decomposition of the organic waste in the water. These emissions are particularly acute in developing countries that tend to have inadequate collection and treatment systems for wastewater. Another form of wastewater is sewage, which produces nitrous oxide (N_2O) from nitrogen. Industrial wastewater can also contain significant nitrogen loading.

Landfilling of solid waste and wastewater accounted for approximately 93 percent of waste emissions in 2005. Of this, 53 percent came from solid waste (totaling 750 $MtCO_2e$) and 40 percent from wastewater (560 $MtCO_2e$). Emissions from sewage account for the remaining 7 percent. All waste emissions are non-CO_2 in the form of methane and N_2O, both of which have much greater global warming potential than CO_2.[72] Landfill gas emits on average approximately 1 tCO_2e per tonne of waste. Recycling and composting reduce the volume of solid waste that must be landfilled. Landfills are maintained according to regulations as the final disposal site of solid waste.

72 Methane's global warming potential (GWP) is about 21 times that of CO_2 over a 100-year period, while the GWP of N_2O is about 296 times that of CO_2 over a 20-year period.

The scope of our waste analysis includes the pre-treatment (i.e., recycling and composting) and treatment (i.e., landfill-gas capture) of solid waste. Wastewater emissions abatement is not assessed due to lack of data. GHG emissions from the use of waste burned for energy are accounted for in the sectors using that waste, and emissions from waste collection are accounted for in the Transportation sector.[73]

Business-as-usual emissions

The BAU case reflects emissions resulting from operations in waste disposal worldwide – i.e., in the absence of significant abatement efforts. In BAU, waste emissions will grow at 0.9 percent per year, reaching 1.7 $GtCO_2e$ per year in 2030, an overall increase of 24 percent in 2005–2030. Growth in the global population and in wealth drives this increase, offset by an expansion of covered landfills in developed countries.

In 2005, waste generation ranges from an estimated 100 kg of waste per capita in India to 225 kg in China, 550 kg in European Union countries, and about 750 kg in the United States.[74] In BAU 2030, developing Asia and Africa account for just over half of emissions, with the United States representing another 10 percent of emissions.

The BAU incorporates a significant degree of emissions abatement by 2030, because of the strict landfill regulations already in place in developed countries and the fact that landfill gas can be used for energy generation. Just over half of the global potential for abatement from recycling and composting is included in the BAU case, while the percentage of implementation for landfill-gas levers in the BAU ranges from 11 percent for flaring to 25 percent for electricity generated from landfill gas. The average degree of implementation for all abatement options in the BAU is already 50 percent in 2030.

The proportion of emissions from solid waste decreases slightly in the BAU case, from 53 percent in 2005 to 51 percent in 2030, while the proportion from wastewater increases respectively.

We draw the BAU primarily from US EPA data and analysis, with additional inputs from the IPCC.[75]

Potential abatement

The abatement levers identified for the Waste sector can be aggregated into three groups (Exhibit 8.8.1):

A. Existing waste. The methane emitted by solid waste in landfills can be captured and used with a system of pipes and wells. Landfill gas then can be used to generate electricity, sold to a nearby industrial user, or burned (flared) to prevent methane from entering the atmosphere. It is technically difficult to collect all of the landfill gas produced and not all techniques can be applied at all landfills. The abatement case assumes that 75 percent of landfill gas can be captured over the lifetime of a landfill. Direct use of landfill gas is assumed to be limited to 30 percent of the

73 Incineration and gasification are excluded from this analysis. In many circumstances, these technologies could be useful in abating emissions.

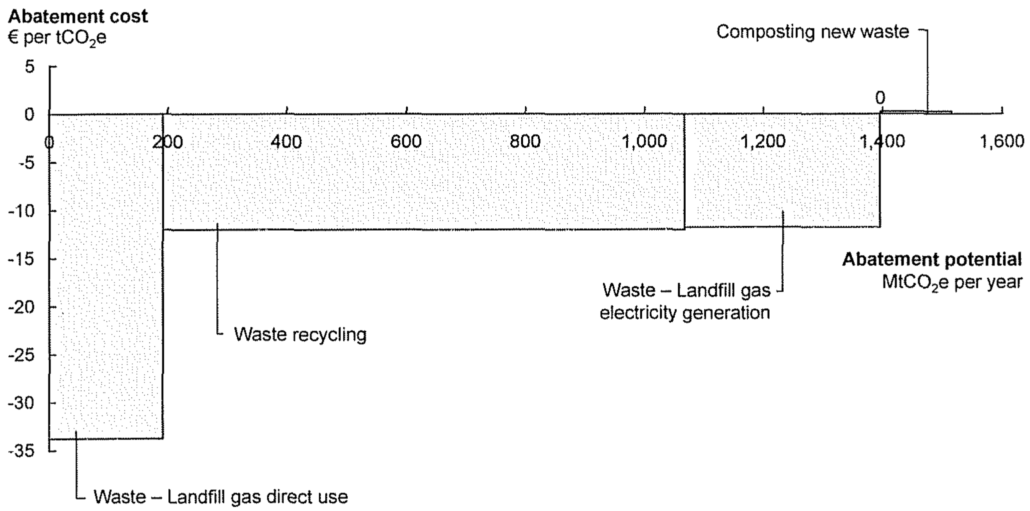
74 This is based on a UN database on waste generation by country.

75 McKinsey thanks the IPCC for contributing to the baseline data and the EPA for its collaboration.

Exhibit 8.8.1

Global GHG abatement cost curve for the Waste sector

Societal perspective; 2030



Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €60 per tCO_2e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play

Source: Global GHG Abatement Cost Curve v2.0

landfill sites, based on the availability of nearby industry that can leverage the energy. Electricity generation from landfill gas is assumed to be limited to 80 percent of the sites, based on the size of landfills where this option is economically attractive.[76] The abatement case assumes that any potential remaining site would apply landfill-gas flaring.[77] Taking the United States as an example, out of an estimated 1,800 landfills, landfill-gas levers would be implemented at about three-quarters in the reference case, with landfill gas captured at the remaining 450 landfills in the abatement case during 2010–2030. Direct use of landfill gas is highly net-profit-positive (€ -34 per tCO_2e) because of the savings from using it as a fuel for nearby industrial facilities. Similarly, landfill gas used to generate electricity also has a significantly negative cost.

B. New waste. Solid waste can be sorted for the recycling of glass, paper/cardboard, plastic, and metal waste, and the composting of organic waste. Recycling and composting reduce the introduction of new waste to landfills, thereby avoiding landfill and industry emissions. In recycling, energy savings from avoided production for new materials (e.g., metals and paper) drives emissions reductions. Recycling has a significant negative cost for the same reason. Recycling reduces emissions by 3.2 tCO_2e to 5.1 tCO_2e per tonne recycled, depending on the regional waste composition. Composting avoids methane emissions from new organic waste. Composting reduces emissions on average by 1.1 tCO_2e per tonne composted. (The overall abatement potential from composting is small because the abatement is accounted for over 35 years.) Composting has a slightly positive cost to society. The abatement case assumes that about 10 percent of solid waste that could be recycled or composted is irrecoverable in developed countries; in developing countries, the figure is up to 15 percent. It is assumed that 100 percent of that recoverable waste

76 We base this on estimates from IPCC experts.

77 The three landfill-gas abatement levers apply to the same sites; overall implementation equals 100 percent with the combined measures. We base the volume of abatement for the three levers applied to landfills on a merit order logic in which the least-expensive lever in 2030 is implemented first.

is recycled and composted by 2030. For recycling only, globally about 440 million tonnes of waste would be processed in the BAU and another 310 million tonnes in the abatement case, giving a total of about 750 million tonnes of recycled waste.

C. Wastewater. Improved treatment of wastewater at current facilities (e.g., better filtering) can reduce emissions. Wastewater treatment facilities can be built in countries with no available facilities, i.e., mainly developing countries. However, given the lack of reliable data on wastewater abatement, we have not estimated the potential in this analysis.

The abatement potential for solid waste is estimated at 1.5 $GtCO_2e$ per year in 2030. Full abatement would reduce emissions to 0.2 $GtCO_2e$ per year, due to the effect of recycling reductions on energy efficiency in various industry sectors. Importantly, recycling abatement is accounted for in the Waste sector but is achieved in relevant industry sectors. Of the abatement potential, approximately 60 percent comes from recycling.

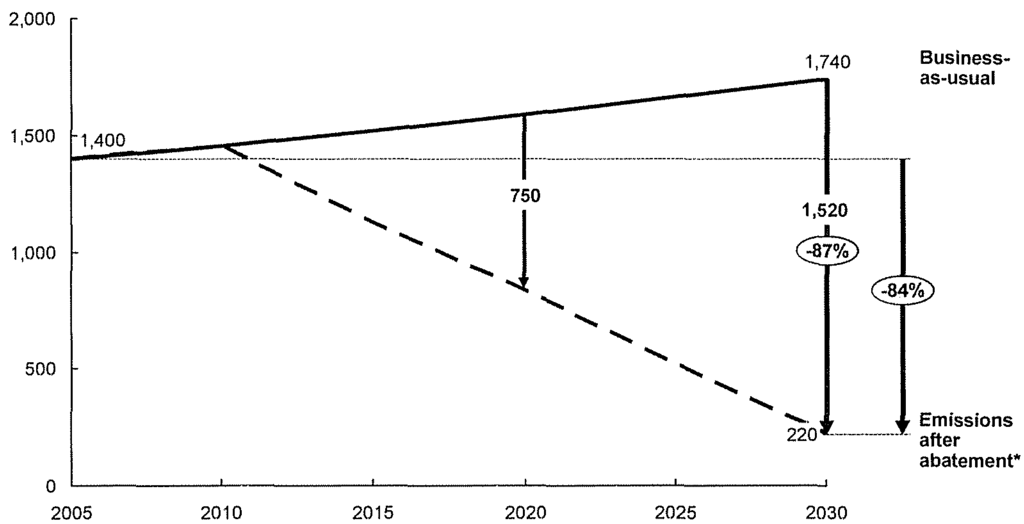
Asia and developing Africa account for 38 percent of the total abatement potential, The United States represents another 16 percent of abatement potential. India, which emits 9 percent of CO_2e in the reference case, accounts for only 1.5 percent of the potential abatement due to a very low proportion of waste collection and a small share of metal in the composition of the country's waste (a component with relatively high abatement potential).

The potential abatement volume increases over time due to gradual implementation of the levers up to 2030 (Exhibit 8.8.2). The average degree of implementation for all waste-abatement options in the abatement case is about 85 percent in 2030 as a certain share of the waste is assumed to be impossible to collect and sort.

Exhibit 8.8.2

Emissions development for the Waste sector

$MtCO_2e$ per year



* Economic potential of technical measures

Note: This is an estimate of maximum economic potential of technical levers below € 60 per tCO_2e if each lever was pursued aggressively It is not a forecast of what role different abatement measures and technologies will play

Source: Global GHG Abatement Cost Curve v2 0

Capital expenditures for waste emissions abatement total about € 210 billion for the full study period. However, operating expenditure savings of € -360 billion outweigh these investments, driven by high operating revenues (i.e., savings from avoided costs). In 2015 investments are still higher than savings and, beginning in 2020, society benefits financially as savings exceed new spending.

Socioeconomic view	**Average cost** (€ per tCO_2e)	**CapEx** (€ billion per year)	**OpEx** (€ billion per year)
2015	-13	9	-5
2020	-13	14	-14
2025	-13	11	-22
2030	-14	8	-30

Implementation challenges

Educational programs to change individual practices, such as recycling and composting habits, and appropriate enforcement of policies will be required to achieve the waste-abatement potential.

Technical constraints (e.g., engineering capacity) will exist for the rollout of the different abatement techniques in some regions, particularly for landfill-gas use. However, we assume that these challenges are resolved by 2030. For example, Germany has achieved very significant reductions in solid waste. Total waste volume declined by 68 percent between 1990 and 2004 and related emissions dropped from about 36 $MtCO_2e$ to 11 $MtCO_2e$ in the same period. These reductions are expected to continue, reaching about 5 percent of 2005 emissions by 2020. The main drivers are regulations requiring the elimination of methane emissions from waste landfilled after 2005, through thermal or mechanical biological pre-treatment, and stringent guidelines to collect gases from residuary landfills. Germany has also expanded incineration using energy recovery (electricity and heat).

8.9 Forestry

Land use, land-use change, and forestry are the fourth-largest source of global greenhouse gas emissions, accounting for 16 percent of global GHG emissions, or 7.4 $GtCO_2e$ per year in 2005.[78] Forestry sector emissions occur mainly thorough the deforestation of tropical forests and the drainage and burning of tropical peatlands. In the absence of abatement measures, we expect Forestry sector emissions to remain substantially unaltered to 2030, reaching 7.2 $GtCO_2e$. The main means of abatement is avoiding deforestation, and the estimated abatement potential for the Forestry sector is very large. Most of the abatement potential is at very low cost. It is difficult to implement the abatement measures identified due to the diffuse nature of the opportunity, the fragmentation of the potential actors, the complexity of implementing effective land-use policies in developing countries, and the need for substantial capacity-building.

Forestry includes land use and land use change. The sector is one of the largest sources of emissions globally – and the second largest source in the developing world. Deforestation emissions account for 73 percent of the total, the rest being due to the drainage and burning of peatlands. Full 88 percent of deforestation emissions result from the deforestation of tropical forests, which occurs because of clearance for agriculture (although tropical forest soil tends to be poor in nutrients) and a lack of clear land ownership. Brazil and Indonesia each account for one-third (1.7 $GtCO_2e$ per year) of 2005 deforestation emissions, with Africa also contributing a significant share (0.9 $GtCO_2e$ per year, or 16 percent).

Forest ecosystems draw down atmospheric CO_2 through photosynthesis and store it in biomass and other carbon stocks. While mature or primary ecosystems are generally in carbon balance (i.e., photosynthesis equals respiration), in young forests photosynthesis exceeds respiration and additional carbon is stored in the ecosystems. In other words, new and young forests display negative CO_2 emissions, and deforested or unsustainably logged forests release positive emissions.

Emissions from land use change can be substantial when mature forests are impacted. Deforestation and unsustainable forest harvesting remove carbon stocks from the forests and release them in the

78 Excluding negative emissions from forest regrowth in the northern hemisphere, and including emissions from peat drainage and fires; see section on BAU emissions below.

atmosphere. It is estimated that a single hectare of primary tropical forest can contain over 800 tCO_2e, nearly two-thirds in the form of above-ground biomass.

Conversion of tropical forest to palm-oil plantation can reduce carbon storage by two-thirds.[79] In 1980–2005, global deforestation removed 332 million hectares of forest – an area the size of India – with estimated cumulative emissions of 138 $GtCO_2e$.[80] The timing of carbon release from deforestation depends on many factors, including the mix of end-uses of the removed wood, the fate of the biomass and wood left on site, and the level of soil disturbance. These factors present potential levers for emissions abatement.

Reducing emissions from deforestation and forest degradation (REDD) is therefore a substantial opportunity for meeting GHG emissions reduction targets. Afforestation, reforestation, and forest management can also contribute to the reduction of GHG through the sequestration of CO_2 from the atmosphere into terrestrial carbon pools.

Although there is substantial consensus on the basic mechanisms of forest-based mitigation, large discrepancies still exist in the scientific community on the size and cost of the opportunity, as well as on the regulatory mechanisms that can be used to capture it. However, the majority of expert forecasts concur in showing a slight decrease in overall forest-based carbon emissions in the future.

The discrepancies are driven by basic uncertainty on actual deforestation rates (both current and future), on the carbon content of the deforested areas, on the rate of carbon loss from deforested areas (both past and current), and on the rate of re-growth of deforested and abandoned areas (both past and current), with different sources reporting base-case deforestation emissions ranging from 3 $GtCO_2e$ per year to more than 8 $GtCO_2e$ annually.

There is also uncertainty about the cost of implementing mitigation levers, mostly due to a lack of substantial experience in implementing the levers. The Kyoto Protocol mechanisms left out forest-based mitigation; as a consequence, until recently there has been limited experience of carbon-based afforestation and reforestation projects, and almost no experience with avoided deforestation. Most published estimates are based therefore on limited empirical evidence.

Business-as-usual emissions

Global deforestation emissions were estimated at 5.4 $GtCO_2e$ per year in 2005. This excludes the negative emissions (i.e., sequestration) from the Forestry sector reported by several industrialized countries. (The largest carbon-emitting nations, including the United States and OECD Europe, are in fact carbon sinks for land use and forestry, while the key sources of carbon emissions are tropical regions.) Peatland and drainage emissions have been estimated to be 2.0 $GtCO_2e$ per year on average over the last decade – 0.6 $GtCO_2e$ per year from decomposition and 1.4 $GtCO_2e$ per year from fires.[81] Following the IPCC'S Fourth Assessment Report, Working Group III, we have included these emissions in our BAU case. Given the high interannual variability in fire emissions and basic uncertainty on the future rate of peatland fires, we have maintained these emissions constant through the study period.

79 FAO data for Democratic Republic of Congo; team analysis based on palm oil plantations in Indonesia.

80 We base this on Houghton estimates of annual emissions from tropical forests in 1980–2005.

81 A. Hooijer, M. Silvius, H. Wösten, and S. Page, PEAT-CO_2, Assessment of CO_2 emissions from drained peatlands in SE Asia. WL Delft Hydraulics and Alterra Wageninger UR, Q3943, 2006.

The BAU case assumes that deforestation will continue at a pace consistent with historical levels – 13 million hectares per year (with deforestation rates of 3.1 million hectares per year in Brazil and 1.8 million hectares per year in Indonesia), corresponding to 0.32 percent of the remaining forest area globally.[82] Deforestation will remain constant globally through 2030 in the BAU, with the exception of a few African countries, where deforestation is assumed to stop when the total forested area reaches 15 percent of the land base.[83] Thus, total emissions from tropical regions are forecast to decline slightly. Developed country emissions or sequestration are assumed to remain at the 2000–2005 average through 2030. In sum, overall emissions in the BAU case are forecast to decline by 3 percent until 2030. There is substantial uncertainty around these baseline emissions, however, because of the uncertainty about the level of past deforestation. Overall, an uncertainty of plus or minus 2 $GtCO_2e$ per year is a reasonable estimate.[84]

Potential abatement

We have identified eight abatement levers in the Forestry sector, grouped into four categories:

1. ***Avoided deforestation* (REDD) (about 65 percent of total potential abatement, 5.1 $GtCO_2e$ per year in 2030).** REDD strategies seek to prevent emissions of terrestrial CO_2 by avoiding a net decrease in forest area or volume. REDD is pursued mostly by social and public-sector stakeholders (e.g., governments, NGOs, and charitable foundations). REDD requires an implementation strategy beyond the project base because of the risk of leakage – i.e., deforestation avoided in one area that causes an increase in deforestation in other areas. REDD measures are not currently integrated within existing compliance markets, although projects have been initiated to generate carbon credits for the voluntary markets. Our volume estimates are based on stopping all deforestation in Asia and Latin America and preventing 70 percent of deforestation in Africa by 2025, based on research indicating that a full cessation of deforestation in the Brazilian Amazon would be feasible within ten years.[85] Our estimates of the mitigation cost and volume from avoided deforestation are based on the following approaches:
   a. To reduce slash-and-burn and other forms of subsistence agriculture; compensation payments and income support to the rural poor and forest people;[86]
   b. To reduce conversion to pastureland and cattle ranching; compensation to landholders for the lost revenue from one-time timber extraction and future cash flow from ranching;[87]

82 Country-level figures are as reported by FAO Forest Resource Assessment 2005 for 2000–2005, which includes both Amazon deforestation, and deforestation in Cerrado and Mata Atlantica. According to INPE, the deforestation rate in the Brazilian Amazon was 2.2 million hectares per year for 2000–2005, declining to 1.2 million hectares a year in 2007.

83 We base deforestation emissions on Houghton's model estimates for tropical regions, and on UNFCCC estimates for developed regions. *Houghton's model is based on* deforestation rates contained in the FAO's Forest resource Assessment 2005, and reference carbon density. As such, it does not include the specific impact of peat decomposition or peat fires. A minimum limit of residual forest area of 15 percent follows Houghton's assumptions and, although somewhat arbitrary, it is not material to the BAU case, impacting only 5 percent of the emissions before the effect of sinks, very small when compared with the basic uncertainty around LULUCF emissions.

84 Estimates of deforestation in the pan-tropics based on remote sensing have been consistently lower than the rates reported by the FAO Forest Resource Assessment. Both the FAO and remote sensing studies are methodologically unable to capture the effect of land degradation and emissions from tropical peatlands.

85 Research conducted by Woods Hole Research Center.

86 Assuming payments of $1,200 annually to Brazilian households, with payments in other regions scaled to the annual income of the poorest 20 percent of the population.

87 Ranching profits are $15/hectare annually in Brazil. Timber extraction is calculated at 70 percent of standing merchantable volume.

c. To reduce conversion to intensive agriculture; compensation to landholders for the lost revenue from one-time timber extraction and future cash flow from agriculture;[88]

d. To reduce unsustainable timber extraction; compensation to landholders for lost timber revenue.[89]

2. **Afforestation of marginal pasturelands and croplands (around 13 percent of total potential abatement, 1.0 $GtCO_2e$ per year in 2030).** Afforestation is the plantation of forest carbon sinks over marginal pastureland and marginal cropland, and is a method of incremental biosequestration of CO_2. Carbon is sequestered in forest carbon pools. Because of the project-based approach of afforestation, private-sector stakeholders (e.g., corporations and asset managers) play an important role. Afforestation is partially integrated in existing compliance markets.[90] The estimated potential implies an incremental afforestation of 92 million hectares in 20 years, or 4.6 million hectares per year—an area larger than Denmark. The afforestation potential depends on the quantity of available marginal cropland and pastureland, which is limited by the need to supply food and feed to a growing population. We account for this limitation in the stated potential.

3. **Reforestation of degraded lands (about 18 percent of total potential abatement, 1.4 $GtCO_2e$ per year in 2030).** Reforestation of degraded lands is the plantation of forest carbon sinks over degraded land with no food or feed production value. We base our estimates of afforestation and reforestation mitigation potential and costs on a "carbon graveyard" forest case in which forests are not harvested. Reforestation projects are similar to afforestation. The two mitigation approaches are jointly referred to as A/R.[91] The estimated potential implies an incremental reforestation of 238 million hectares in 20 years, or 11.9 million hectares per year—about twice the size of Croatia. While the reforestation potential is limited in a few regions by the amount of available degraded lands, in most regions it is the estimated maximum annual reforestation rate.

4. **Forest management measures (about 4 percent of total potential abatement, 0.3 $GtCO_2e$ per year in 2030).** Forest management is the increase of the carbon stock of existing forests based on active or passive management options such as fertilization, fencing to restrict grazing, fire suppression, and improved forest regeneration. Thus, forest management is a method of incremental biosequestration of CO_2. Private-sector stakeholders play an important role in forest management because of the project-based approach to creating a net increase of standing stock. Most forest management measures are not integrated within existing compliance markets. The estimated potential is based on applying forest-management measures to the global forest area, including temperate and boreal forests, at a rate that is feasible for the forests of the United States.[92] While covering a very large area, the total abatement potential of forest management is limited by timber production and harvesting; i.e., they are purely efficiency improvements in managed forests.

REDD dominates the potential abatement of emissions, followed by A/R, with limited opportunities in forest management (Exhibit 8.9.1).

88 Reference crops are soybeans for South America and palm oil for Asia and Africa. Timber extraction is calculated at 100 percent of standing merchantable volume.

89 Timber extraction is calculated at 15 percent of standing merchantable volume.

90 Annual rental for crop and pasture lands is based on regional averages. One-time capital investment and annual management costs are based on US estimates. Payments are matched to carbon flux, assuming full repayment of capital investment and present value of annual expenditures over 50 years of constant sequestration.

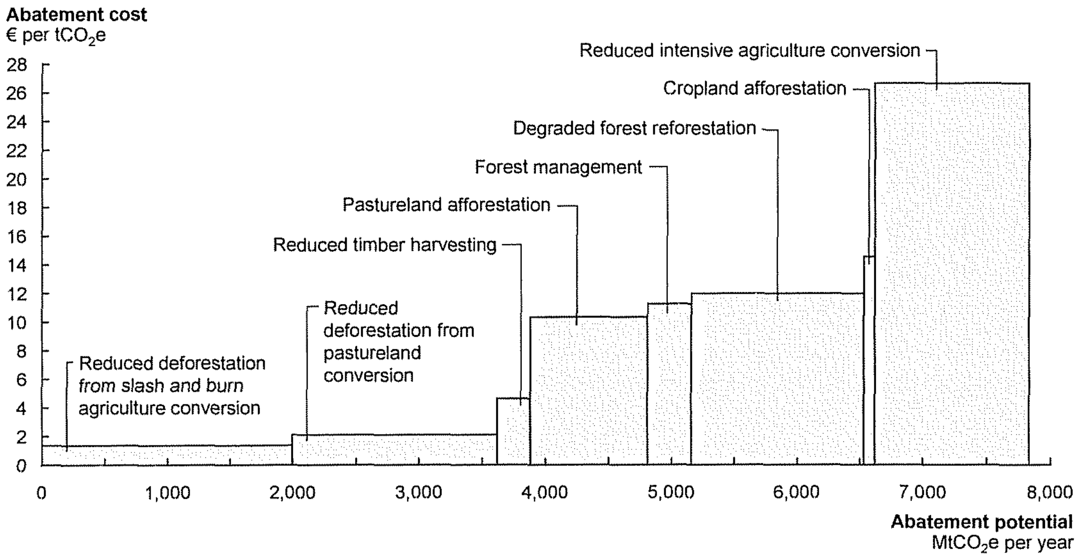
91 One-time capital investment and annual management costs are based on US and IPCC estimates.

92 Estimate by the US Forest Service.

Exhibit 8.9.1

Global GHG abatement cost curve for the Forestry sector

Societal perspective; 2030



Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €60 per tCO_2e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play.
Source: Global GHG Abatement Cost Curve v2 0

The study reveals three key observations:

- A large, low-cost amount of potential abatement from REDD (3.6 $GtCO_2e$ per year) derives from activities that yield little economic value, including slash-and-burn agriculture and conversion to pasture;
- A/R is generally less expensive than avoiding conversion of forests to high revenue-intensive agricultural options;
- Afforestation of marginal croplands has very limited potential due to competition with food, feed, and bioenergy demands.

In sum, the estimated abatement potential by 2030 for land use, land-use change, and forestry is very large, and most of the potential is at very low cost. Abatement in this sector could reduce total emissions to *negative* 0.7 $GtCO_2e$ per year in 2030 due to creating carbon sinks. This is an abatement of 7.8 $GtCO_2e$ per year compared with the BAU case, which corresponds to a 109 percent reduction in BAU emissions in 2030 (Exhibit 8.9.2).

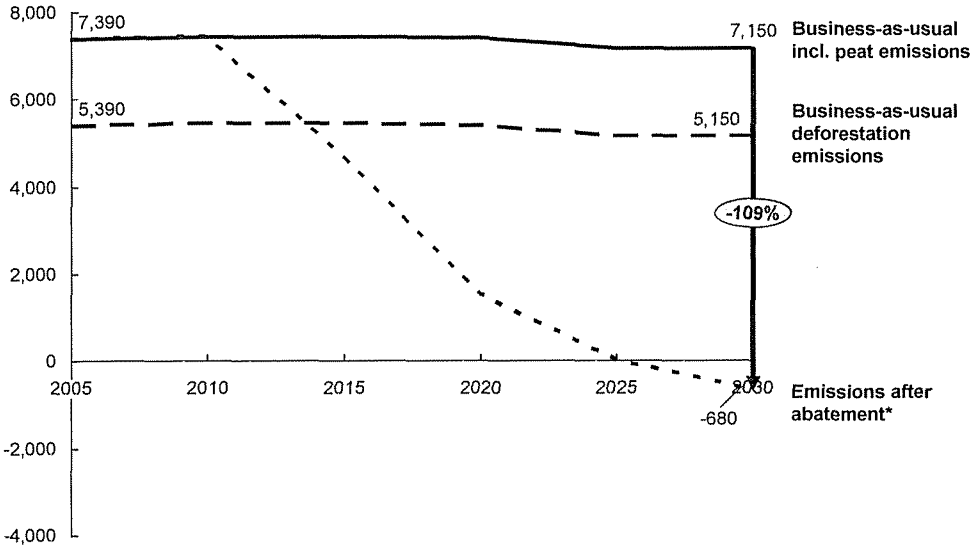
Nearly two-thirds of the overall abatement potential is based on mitigation of emissions of terrestrial carbon from deforestation activities, while the remaining 35 percent is based on offsets; i.e., on the absorption of CO_2 into terrestrial carbon pools.

The costs for forest-based abatement are relatively low. Nearly the entire potential identified would cost below € 30 per tCO_2e. In particular, avoided deforestation from slash-and-burn agriculture, and avoided deforestation from cattle ranching, offer high potential abatement at a very low average cost

Exhibit 8.9.2

Emissions development for the Forestry sector

$MtCO_2e$ per year



* Economic potential of technical measures

Note: This is an estimate of maximum economic potential of technical levers below € 60 per tCO_2e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play.

Source: Global GHG Abatement Cost Curve v2.0

of below € 2 per tCO_2e. We did not identify any net profit-positive potential in the forest sector – both avoided deforestation and the creation of incremental offsets compared with the baseline involve economic costs.

Socioeconomic view	**Average cost** (€ per tCO_2e)	**CapEx** (€ billion per year)	**OpEx** (€ billion per year)
2015	9	15	1
2020	9	31	2
2025	9	41	2
2030	9	43	3

There is broad agreement that forest-based mitigation is large and inexpensive, but estimates of size and cost are very uncertain. While the cost of abatement measures is not expected to increase through 2030, it should be noted that abatement-cost forecasts are based on current agricultural commodity and land rental prices. A steep increase in commodity prices or land rents would lift the abatement cost. All cost estimates are highly dependent on which mechanisms were implemented to pursue forest-carbon mitigation – e.g., national funds versus market-based solutions.

While these costs include ongoing the monitoring and management of preserved forests, they do not include transaction costs, the cost of building new infrastructure, or the capacity-building cost necessary to set up the monitoring and management infrastructure, which itself could account for a reasonably large portion of the total cost in tropical countries. Also, the costs of avoiding leakage and insuring the permanence of carbon stocks against natural disturbance events are not included.

The annual cash flow needed during 2010 to 2030 equals about 35 percent of the total value of the global timber industry. The capital expenditures during this period are equivalent to 20 times current foreign aid to the agriculture and forestry sectors globally.

Abatement cash flow is dominated by the investment in REDD, accounting for about 80 percent of the total in 2030.[93] We have also treated Initial investments in A/R as capital expenditures in this study. Part of the REDD investment potentially could be shifted by converting it from a one-time investment to annual payments, although the specifics would depend on the REDD mechanisms adopted.

Geographical differences. The great majority – 88 percent – of the overall abatement potential comes from tropical regions, all of which are located in the developing world. REDD opportunities are concentrated in Latin America, developing nations in Asia, and Africa. Opportunities for A/R and forest management can be found globally, but the bulk is again concentrated in the developing world.

Low-cost options for REDD are present in all tropical regions, while higher-cost options are found mostly in Africa and developing nations in Asia. Currently, slash-and-burn agriculture – whose mitigation is very inexpensive – accounts for a large percentage of deforestation emissions from Africa (53 percent), Asia (44 percent), and Latin America (31 percent). Pastureland and cattle ranching, which are also cheap mitigation options, account for the majority of deforestation emissions from Latin America (65 percent) but a much lesser proportion of emissions from Asia (6 percent) and Africa (1 percent). Timber extraction – which is more expensive to mitigate than the previous two categories but still relatively low cost – accounts for a small proportion of emissions from Africa (10 percent), Asia (6 percent), and Latin America (3 percent). Finally, intensive agriculture – the most expensive abatement lever in this sector at € 27 per tCO_2e – accounts for 44 percent of emissions in Asia, 35 percent in Africa, and only 1 percent in Latin America.

Implementation challenges

Practical, political, and ethical reasons are likely to disconnect compensation to potential deforesters from the opportunity cost. For example, transfers to forest people or the landless poor might need to exceed opportunity costs substantially, and illegal logging or conversion to pasture might not be compensated at all.

A "payment for ecosystems services" approach, in which landholders are compensated for avoiding deforestation, could have very high inefficiencies; i.e., compensation is likely to go to some who would have not deforested in any case, increasing payment by a factor of between 2 times and 100 times. These payments would be transfers and not true economic costs to global economies, but would generate a certain amount of true costs related to an increased administrative burden, and could therefore inflate the budget of an avoided deforestation scheme when compared with the costs reported here.

National infrastructure and capacity-building costs are almost never accounted for in published cost estimates. These values are dependent on current institutional capacities, which are highly variable between high deforestation countries, and the implementation approaches taken.

93 The investment in REDD is assumed to be fully capitalized upfront; i.e., full capitalization of future liabilities for avoided deforestation support programs

8.10 Agriculture

Agriculture accounts for about 14 percent of global GHG emissions, or 6.2 $GtCO_2e$ per year in 2005. Developing regions represent the largest share of these emissions, with Asia, Latin America, and Africa generating almost 80 percent of the total. About 70 percent of total emissions come from agricultural soil practices and enteric fermentation in livestock. In the absence of abatement measures, worldwide agricultural emissions are projected to grow by approximately 1.0 percent annually to about 8 $GtCO_2e$ per year, driven by increased population and meat consumption. The abatement potential in the Agriculture sector is very large at 4.6 $GtCO_2e$ per year identified by 2030, which is a little more than half of the emissions in the reference case. Three-quarters of the abatement potential is through carbon sequestration in soils. Most of the abatement levers come at a neutral cost or are net-profit-positive to society and require no substantial capital investment. However, we cannot understate the implementation challenges given the large complications caused by the high degree of fragmentation in agriculture in most parts of the world, especially in developing countries. The uncertainty around the abatement potential is significant, making the monitoring and the accounting of the measures even more challenging. Finally, most of the sequestration measures are estimated to be active for 20 to 40 years, which means that other levers will need to be phased in to replace these after 2030–2050.

Agriculture is comparable to the Road Transport and Forestry sectors in terms of the size of the sector's global emissions. Rather than carbon dioxide, agricultural emissions are in the form of nitrous oxide (N_2O) (46 percent of sector emissions) and methane (54 percent),[94] although the fact remains that carbon sequestration has a very large potential for GHG abatement in agriculture. We can divide emissions into five categories:

- **Agricultural soils** (nitrous oxide) – representing 37 percent of sector emissions (2.3 $GtCO_2e$ per year) as of 2005;
- **Livestock enteric fermentation** (methane) – 31 percent (1.9 $GtCO_2e$ per year);
- **Rice cultivation** (methane) – 13 percent (0.9 $GtCO_2e$ per year);
- **Livestock manure management** (methane and nitrous oxide) – 7 percent (0.4 $GtCO_2e$ per year);
- **Other agricultural practices**, such as open burning during agricultural activities (nitrous oxide and methane) – 12 percent (0.7 $GtCO_2e$ per year).

94 CO_2 releases from the conversion of forests to agricultural production are allocated to the Forestry sector in this analysis

Agriculture is a very diverse sector; crop and livestock practices range from subsistence farming to intensive and industrial agriculture. In most countries, agriculture is a key national industry. The sector is highly fragmented, particularly in developing countries where a large percentage of the abatement potential is located. Farmers are believed to represent about 35 percent of the global workforce in 2007 or approximately 1 billion workers. Agricultural consumption increases with increased population and increased wealth. China accounted for 20 percent of Agriculture-sector emissions in 2005, Latin America 19 percent, and Africa 16 percent. Together, Asia, Latin America, and Africa create 76 percent of agricultural emissions. This analysis encompasses the production of agricultural commodities, including crops and horticultural products, and livestock. However, we exclude the distribution of agricultural products and processing/ manufacturing, which other sectors capture.

Business-as-usual emissions

Without abatement measures, agricultural emissions are forecast to climb steadily from 6.2 $GtCO_2e$ in 2005 to 8.2 $GtCO_2e$ per year in 2030 – a growth rate of 1.1 percent per year or 31 percent increase in emissions over the whole period from 2005 to 2030. Three factors drive this increase: worldwide population growth (25 percent from 2005–2030); global development resulting in increased per capita GDP; and an expected worldwide shift in nutrition intake toward meat. The BAU case does not account for the consequences that climate change might have on agriculture (e.g., changes in rainfall and growing patterns), as the implications are unclear both in terms of the magnitude of the impact and the positive and negative aspects for different regions. The reference case includes the effect of carbon sequestration, which is estimated to bring GHG emissions down to 7.9 $GtCO_2e$ from 8.2 $GtCO_2e$ per year in 2030.[95]

The share of emissions from developing countries is expected to increase over time as a result of increasing population and GDP growth. Asia, Latin America, and Africa are projected to represent 79 percent of agricultural emissions in 2030 in the reference case (up from 76 percent in 2005).

We base the reference case on data from the US Environmental Protection Agency (EPA), the UN Food and Agriculture Organization (FAO), and the Intergovernmental Panel on Climate Change (IPCC). The US EPA baseline is widely recognized as the most accurate description of GHG emissions in agriculture.[96]

Potential abatement

The identified abatement measures for the Agriculture sector have a total potential of 4.6 $GtCO_2e$ per year worldwide by 2030, equivalent to nearly 60 percent of emissions (compared with the BAU case). The abatement case is some 50 percent lower than 2005 emissions. It is important to note that the uncertainty around the abatement potential is significant and will be dependent on the geographies and climate.[97]

We have modeled 11 abatement levers for the Agriculture sector, which we can aggregate into four categories (Exhibit 8.10.1):

95 The EPA baseline excludes carbon sequestration levers.

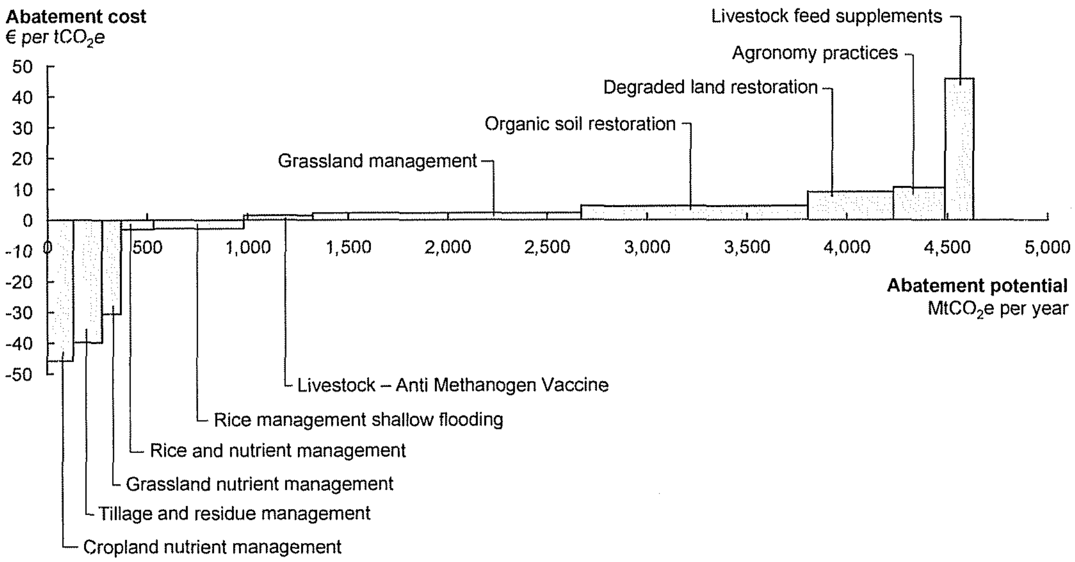
96 Global Mitigation of Non-CO_2 Greenhouse Gases, EPA, June 2006, has been used to define the baseline scenario through 2030.

97 Abatement figures are averages, which reflect higher reduction potential for some areas and lower or even potentially negative abatement (i.e., an increase in emissions) for other areas.

Exhibit 8.10.1

Global GHG abatement cost curve for the Agriculture sector

Societal perspective; 2030



Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €60 per tCO_2e if each lever was pursued aggressively It is not a forecast of what role different abatement measures and technologies will play

Source: Global GHG Abatement Cost Curve v2 0

A. Pastureland (29 percent of abatement potential, 1.3 $GtCO_2e$ per year by 2030). Improved grassland management is the single largest abatement lever, which consists of increased grazing intensity, increased productivity, irrigation of grasslands, fire management, and species introduction. Pastureland management can include the use of perennial and semi-perennial grasses as energy crops, which in turn can increase agricultural productivity. In addition, grassland nutrient-management practices can be improved through more accurate nutrient additions and better fertilization. Average abatement from this lever is around 0.4 tCO_2e per hectare out of a global total of about 3,250 million hectares of pastureland.

B. Land restoration (34 percent of abatement potential, 1.6 $GtCO_2e$ per year by 2030). Land degraded by excessive disturbance, erosion, organic matter loss, acidification, for instance, can be restored through revegetation, improved fertility, reduced tillage, and water conservation.[98] Reestablishing a high water table for organic soils in order to avoid decomposition is a large abatement lever.[99] Reaching the full annual 1.1 $GtCO_2e$ per year of abatement in organic soils requires 1.1 million hectares of land being restored annually between 2020 and 2030, an area almost the size of Northern Ireland. Restoration of degraded land has a potential of 0.5 $GtCO_2e$ per year and but would require a much higher amount of land restored of 6.1 million hectares annually.

C. Cropland management (27 percent of abatement potential, 1.2 $GtCO_2e$ per year by 2030). Management of cropland to reduce GHG emissions consists of improved agronomy practices (such as improved crop rotations, less-intensive cropping systems, and extended use of cover crops), reduced tillage of the soil, reduced residue removal (from burning, for instance), improved

98 Land restoration does not include reforestation measures, which are accounted for in the Forestry sector.

99 *Organic or peaty soils contain high densities of carbon accumulated over many centuries because decomposition is suppressed by absence of oxygen under flooded conditions. To be used for agriculture, these soils are drained, which aerates the soil, favoring decomposition and creating high CO_2 and N_2O fluxes. Draining organic soils usually suppresses methane emissions, but this effect is far outweighed by pronounced increases in N_2O and CO_2.*

nutrient management (such as slow-release fertilizer forms, nitrification inhibitors, and improved application rates and timing), and better rice management and rice-nutrient management practices (such as mid-season and shallow-flooding drainage to avoid anaerobic conditions, and use of sulfate fertilizer instead of traditional nitrogen fertilizer). Rice practices, which are mostly limited to developing Asia, are the largest single lever in this category.[100] Average abatement from cropland management is around 0.7 tCO_2e per hectare from the global total of about 1,750 million hectares of cropland.

D. Livestock management (10 percent of abatement potential, 0.5 $GtCO_2e$ per year by 2030). Dietary additives and feed supplements can reduce methane emissions from livestock. Livestock account for about one-third of global methane emissions. Additives that are currently available are relatively expensive but vaccines against methanogenic bacteria are being developed. This 0.5 $GtCO_2e$ per year corresponds to a 19 percent reduction in livestock emissions.

Although agricultural emissions today consist primarily of non-CO_2 GHGs, nearly three-quarters of the abatement potential is related to CO_2 through the avoidance of the release of carbon from soils or through additional carbon sequestration into soils.

Carbon sequestration levers include reduced tillage, grassland management, and degraded land restoration.[101] Organic-soils restoration accounts for one-third of carbon sequestration – and alone represents one-quarter of the total abatement potential in the Agriculture sector – as this effectively both stops the release of the carbon stock to the atmosphere and allows further build-up of carbon in the soil. Although there are only 25.2 million hectares worldwide of organic soils – 0.5 percent of total agricultural land – these soils have very high abatement potential per hectare.[102]

Organic-soils restoration often requires a switch from cropland back to swamps or peat soils, which implies a shift of food production to other areas. The impact of this shift can be very significant for countries and regions dominated by organic soils, such as Scandinavia and some Southeast Asian nations. This approach might meet resistance in favor of local food production, and therefore implementation of this lever might be limited in practice. On the other hand, global trade could make up for losses in local food production. For these reasons, the cost curve assumes implementation of organic soils restoration at 90 percent of the potential.

Nearly 90 percent of total abatement comes from measures related to soils.[103] After full abatement, emissions from soil would decline to 0.5 $GtCO_2e$ per year in 2030. Emissions from livestock increase slightly in the abatement case compared with 2005 to 2.7 $GtCO_2e$ per year in 2030.

Cropland and pastureland improvements correspond to a decrease in emissions from around 0.8 tCO_2e per hectare of land in 2005 to about 0.3 tCO_2e per hectare in 2030, an improvement of some 65 percent.

In sum, the estimated abatement potential by 2030 for agriculture is large relative to emissions, and most of the potential would come at a low cost (Exhibit 8.10.2). However, carbon sequestration declines in potential after 20 to 40 years as soils build up to their maximum carbon potential.

100 China already uses mid-season drainage in 80 percent of applications.

101 Other levers such as nutrient management can, in addition to reducing nitrous oxide emissions, also have a positive impact on the sequestration of carbon.

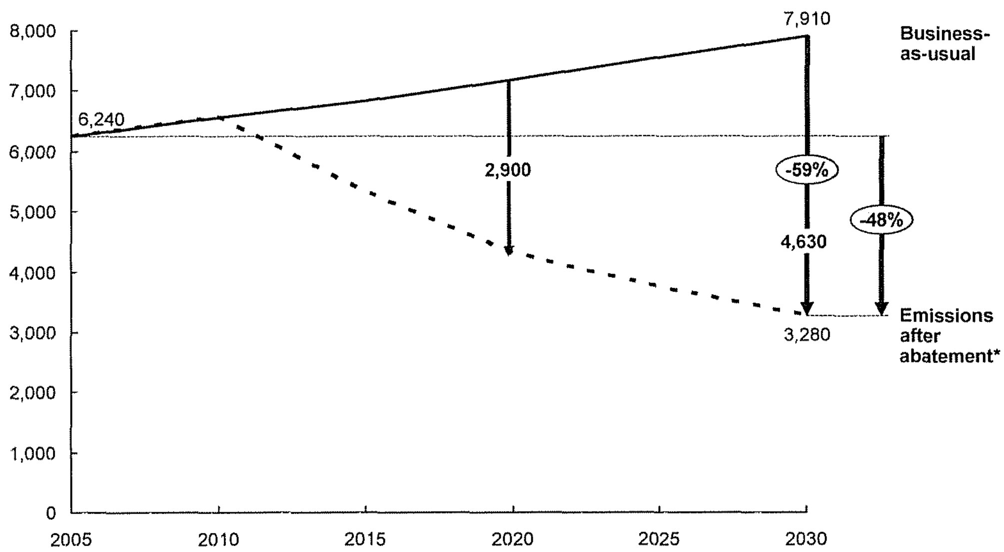
102 Organic or peaty soils contain high densities of carbon accumulated over many centuries because decomposition is suppressed by an absence of oxygen under flooded conditions as well as by soil build-up.

103 The volume of abatement for the levers on soils is based on potential per hectare estimated by the IPCC.

Exhibit 8.10.2

Emissions development for the Agriculture sector

$MtCO_2e$ per year



* *Economic potential of technical measures*
Note: This is an estimate of maximum economic potential of technical levers below € 60 per tCO_2e if each lever was pursued aggressively
It is not a forecast of what role different abatement measures and technologies will play
Source: Global GHG Abatement Cost Curve v2 0

Furthermore, for most of the levers involved in carbon sequestration, a return to previous agricultural practices including high tillage levels would not only immediately stop the intake of carbon but also return the sequestered CO_2 to the atmosphere.

The average cost of abatement for all measures is very low, at around € 1 per tCO_2e in 2030 and, within this average, most measures would be very inexpensive as they are assumed to imply small changes in agricultural practices and no significant capital investments. Soil restoration requires significant implementation and opportunity costs, but these are balanced by a large CO_2-abatement potential per hectare. For example, for organic soils, the implementation costs are about € 227 per hectare and the potential estimated at between 30 tCO_2e and 70 tCO_2e per hectare. Nutrient management is highly net-profit-positive on average, due to a reduction in fertilizer use. Tillage management also is net-profit-positive to society, since an increase in yield leads to a reduction in labor costs. Negative measures represent about 20 percent of the abatement potential. At the other end of the cost range, livestock feed supplements have a relatively high cost of abatement, since high doses are required per animal to achieve the abatement.

These cost calculations exclude program and transaction costs for two reasons. First, there are different routes to implementation, which have extremely different financial implications (e.g., through subsidies or taxes). Second, if implementation is accomplished through training programs and subsidies, exact costs are very hard to estimate. We investigated three categories of implementation costs: measurement and monitoring (estimated at € 0.2 per tCO_2e), capacity and infrastructure building (€ 0.7 per tCO_2e), and carbon-credit-monetization costs (€ 0.2 per tCO_2e). These categories add up to an estimate of € 1.1 per tCO_2e (in line with data from external sources), leading to a total implementation cost of about € 3.8 billion for the Agriculture sector in 2030. However, uncertainty is high (by a factor of two to three times) in all such cost estimates. Further investigation is warranted, given the magnitude of the implementation costs and the high uncertainty level of current best estimates.

Socioeconomic view	**Average cost**[64] (€ per tCO_2e)	**CapEx** (€ billion per year)	**OpEx** (€ billion per year)
2015	-0.5	0	-0.5
2020	-0.5	0	-1.1
2025	0.5	0	0.3
2030	1.2	0	3.8

The total expenditures for all abatement levers over 2010–2030 is € 13 billion and increase over this period as abatement levers are implemented, whether in terms of land or livestock, incurring costs (of savings) each year. Levers are assumed to not require any substantial capital investment; the cash flow required is for operational expenditures only.

Implementation challenges

The sheer size of land areas around the world and the number of farmers involved in measures such as reduced tillage or grassland management implies massive implementation challenges for all countries in abating GHG emissions from agriculture. Yet many of the abatement practices we have identified would have a net positive impact on farmers. They would allow much more sustainable agriculture in the long run; yields can be increased with reduced tillage and residue management; nutrient costs can be decreased with better nutrient application and reduced run-offs for cropland, rice and grassland; yields can be improved on degraded land by restoring them to their original state to reduce the risk of soil erosion; and the economics of cattle-raising can be improved with vaccines.

Agriculture is highly decentralized in most parts of the world and achieving the abatement potential requires a mix of government policies – appropriately enforced – and educational programs to change farming practices. Many experts argue that emissions abatement in agriculture is directly linked to the pace of economic development, making development policy particularly relevant given the high share of emissions in the developing world.

The complexity and the unpredictability of natural processes render measurement and monitoring of agricultural-emissions abatement extremely difficult. Furthermore, the fact that in most geographies farming often equates to living at the level of subsistence makes the assessment of pure climate-change issues insufficient. We note in particular:

- Agriculture, like the Forestry sector, faces several hurdles to effective abatement. These include "leakage" (e.g., organic soils restoration in one area leads to degradation of organic soils elsewhere); permanence (all carbon soil-enhancing measures such as reduced tillage face the risk of future disturbances releasing the carbon back to the atmosphere); additionality (proving that a project generates a reduction in emissions beyond that which would have occurred in its absence); and measurability/baselining (the complexity of measuring the impact, which can vary significantly from one region to the next);

104 The reason why the average cost of abatement rises to 2030 is that more expensive levers are implemented later in the period. For instance, we assume that livestock measures happen later on in the period as feed supplements are still in the development stage.

- Currently available measurement techniques generally fall short in assessing the interactions and interdependencies between the ecological, economic, and social impacts of agricultural-emissions abatement and the trade-offs in pursuing one measure at the expense of another;
- Many of the measurement techniques available today are not useful to farmers, being too time-consuming to implement in their day-to-day work and therefore making it difficult for them and their families to monitor progress on agricultural sustainability;
- Finally, many of the strategies relating to sustainable agriculture require 5–10 years of implementation (i.e., a full crop rotation) before they result in measurable evidence of payoff.

The challenge for successful GHG mitigation in the Agriculture sector will be to remove these barriers by implementing creative policies. Identifying policies that provide economic and social benefits as well as environmental sustainability will be critical for ensuring that effective GHG mitigation options are widely implemented in the future.

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Appendix

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Appendix II – Glossary

Abatement costs	*Additional costs (or net benefit) of replacing a technology in the reference/business-as-usual development by a low-carbon alternative.* Measured as € per tCO_2e abated emissions. Includes annualized CapEx repayments and Opex
Abatement cost curve	Compilation of abatement potentials and costs
Abatement lever	See "lever"
Abatement potential	Potential to reduce emissions of GHGs compared to the business-as-usual development by implementing an abatement lever. Measured in tCO_2e per year. Only limited by technical constraints (e.g., maximum industry capacity build-up). Potential is incremental to business-as-usual
Business-as-usual (BAU)	Baseline emissions scenario to which abatement potential refers. Based primarily on external forecasts, e.g., IEA and EPA projections
CapEx	Incremental capital expenditure (investment) required for an abatement lever compared with business-as-usual
CCS	Carbon capture and storage – technologies for capturing and storing GHGs, mostly underground
CDM (projects)	Clean development mechanism – mechanism in the framework of the Kyoto Protocol that gives emitters of signatory states the option of investing in projects in developing countries under specified conditions and receiving CO_2 certificates for this
CHP	Combined heat and power (plant)
CNG	Compressed natural gas
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent is the unit for emissions that, for a given mixture and amount of greenhouse gas, represents the amount of CO_2 that would have the same global warming potential (GWP) when measured over a specified timescale (generally, 100 years)
Decision maker	*The party that decides on making an investment, i.e., a company (e.g., as* owner of an industrial facility) or an individual (e.g., as owner of a car or home)
EAF	Electric arc furnace – for steel production, in contrast to the integrated route of blast furnace and oxygen steel converter

EU ETS	Emissions Trading Scheme of the European Union
€ or EUR	Real 2005 Euro
EV	(Battery) Electric vehicle
Frozen technology	Increase in emissions due to growth in production considering the current (2005) technology level fixed over time, thus no decarbonization of current technologies or from new emerging technologies
Greenhouse gas (GHG)	Greenhouse gas in the context of the Kyoto Protocol, i.e., CO_2 (carbon dioxide), CH_4 (methane), N_2O (nitrous oxide), HFC/PFC (hydrofluorocarbons), and SF_6 (sulfur hexafluoride)
Gt	Gigatonne(s), i.e., one billion (10^9) metric tonnes
GWP	Global warming potential. An index, based upon radioactive properties of well-mixed greenhouse gases, measuring the radioactive forcing of a unit mass of a given well mixed greenhouse gas in today's atmosphere integrated over a chosen time horizon, relative to that of CO_2. The GWP represents the combined effect of the differing lenghts of time that these gases remain in the atmosphere and their relative effectiveness in absorbing outgoing infrared radiation. The Kyoto Protocol is based on GWPs from pulse emissions over a 100-year time frame.
HDV	Heavy duty vehicle
ICE	Internal combustion engine
IGCC	Integrated gasification combined cycle – combined gas and steam turbine system with upstream coal gasification system
kWh	Kilowatt hour(s)
(Abatement) lever	Approach to reducing greenhouse gas emissions compared to the business-as-usual, e.g., use of more carbon-efficient processes or materials. Focus in this research has been on technical abatement levers, i.e., levers without a material impact on the lifestyle of consumers
LDV	Light duty vehicle
MDV	Medium duty vehicle
Mt	Megatonne(s), i.e., one million (1,000,000) metric tonnes
MWh	Megawatt hour(s), i.e., one million Watt hours
OpEx	Incremental operating cost required for the abatement lever compared to business-as-usual. Includes incremental operational and maintenance cost and incremental savings (e.g., from reduced energy consumption)
PHEV	Plug-in hybrid electric vehicle (see transport sector section for detailed definition)

Sector	Grouping of businesses or areas emitting GHGs, specifically: ***Power:*** Emissions from power and heat generation, including for local and district heating networks ***Industry:*** Direct emissions of all industrial branches with the exception of Power generation and the Transportation sectors. Indirect emissions are accounted for in the power sector ***Buildings:*** Direct emissions from private households and the tertiary sector (commercial, public buildings, buildings used in agriculture). Indirect emissions are accounted for in the power sector ***Transport:*** Emissions from road transport (passenger transportation, freight transportation), as well as sea and air transport ***Waste:*** Emissions from disposal and treatment of waste and sewage ***Forestry:*** Emissions from Land Use, Land Use Change and Forestry (LULUCF), mainly from deforestation, decay and peat ***Agriculture:*** Emissions from livestock farming and soil management
t	Metric tonne(s)
TWh	Terawatt-hour(s), i.e., one trillion (10^{12}) Wh
$ or USD	Real 2005 US Dollars

Appendix III – Methodology

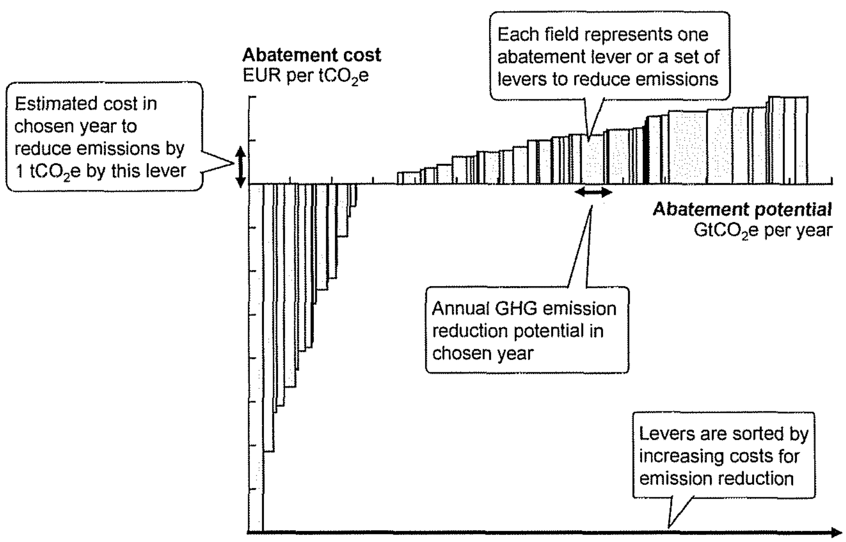
This section describes the methodological approach to the analysis of abatement (or mitigation) potentials, costs, and investments.

Development of the Abatement Cost Curve

The combined axes of an abatement cost curve depict the available technical measures, their relative impact (emission volume reduction potential) and cost in a specific year (Exhibit A.III.1). Each bar is examined independently to quantify both dimensions.

Exhibit A.III.1

Key cost curve dimensions



Source: Global GHG Abatement Cost Curve v2.0

The basic logic of the cost curve is that it displays the abatement potential and corresponding cost for abatement "levers" relative to a business-as-usual (sometimes referred to as "reference case") scenario in a given year.

The width of each bar represents the economic *potential* (not a forecast) to reduce annual GHG emissions from that opportunity. The volume potential assumes concerted global action starting in 2010 to capture each opportunity. The potential reflects the total active installed capacity of that abatement lever in the year of the analysis, irrespective of when this capacity has been built.

The height of each bar represents the average cost of avoiding one metric tonne of tCO_2e in the year of the analysis by each opportunity. The cost reflects the total active capacity of that opportunity, thus is a weighted average across sub-opportunities, regions, and years.

To ensure comparability across sectors and sources, all emissions and sinks have been measured in a common way, using CO_2 equivalents measured in metric tonnes (tCO_2e). The merit order of abatement levers is based on the lowest cost measures (in € per tCO_2e) as of 2030.

Viewed as a whole, the abatement cost curve illustrates the "supply" of abatement opportunities independently from a target (the possible "demand") for abatement. By definition, abatement potential is attributed to the sector in which the abatement lever is implemented. For example, if an abatement lever in a consuming sector (e.g., LEDs in buildings) reduces electricity consumption, the resulting emission reduction in the power sector is attributed to the consuming sector.

Therefore, the baseline for all consuming sectors includes indirect emissions from the power sector. The same relation as for electricity holds true for fossil fuel between the transport and petroleum and gas sectors. To avoid double counting of reductions, the production output in the producing sectors (power, petroleum and gas) is reduced accordingly before abatement measures in that sector are applied.

The uncertainty can be significant for both volume and cost estimates. There are two key sources of this uncertainty: what implementation is feasible to achieve in reality (highest in the Forestry and Agriculture sectors) and the cost development for key technologies.

Calculating Abatement Potential

Abatement potential is defined as the volume difference between the emissions baseline and the emissions after the lever has been applied. The emissions baseline is calculated from several driver values, such as carbon intensity of a specific fossil fuel, production volume of a basic material or fuel consumption of a vehicle. Each abatement lever changes (usually reduces) specific driver values, for which the quantification is determined by literature and expert discussions. An illustrative example would be that fuel consumption can be reduced to 70% by passenger car improvements. This leads to an abatement potential of 30% of initial fuel combustion emissions.

Due to merit order logic of levers adhering to "lowest cost first" principle, the lever with the next higher cost is applied on a new baseline after reductions from all previous levers. Each abatement lever is assessed independently in each region.

Calculating Abatement Costs

Abatement costs are defined as the incremental cost of a low-emission technology compared to the reference case, measured as € per tCO_2e abated emissions. Abatement costs include annualized repayments for capital expenditure and operating expenditure. The cost does therefore represent the pure "project cost" to install and operate the low-emission technology. Capital availability is not considered a constraint.

Abatement costs are calculated according to the formula in Exhibit A.III.2. The full cost of a CO_2e efficient alternative incorporates investment costs (calculated as annual repayment of a loan over the lifetime of the asset), operating costs (including personnel and materials costs), and possible cost savings generated by use of the alternative (especially energy savings). The full cost does not include transaction costs, communication/information costs, subsidies or explicit CO_2 costs, taxes, or the consequential impact on the economy (e.g., advantages from technology leadership).

Exhibit A.III.2

Abatement cost formula

$$\text{Abatement cost} = \frac{[\text{Full cost of } CO_2e \text{ efficient alternative}] - [\text{Full cost of reference solution}]}{[CO_2e \text{ emissions from reference solution}] - [CO_2e \text{ emissions from alternative}]}$$

Operating expenditure is assessed as a real amount to be expensed in each year.

Capital expenditure is accounted for as annualized repayments. The repayment period is the functional life of the equipment. The interest rate used is the real long-term government bond rate of 4 percent, based on historical averages for long-term bond rates.

The cost curve takes a societal perspective instead of that of a specific decision-maker, illustrating cost requirements to the society. Given country differences in taxes, subsidies, interest rates and other cost components a global decision-maker perspective does not exist. This societal perspective enables the usage of the abatement cost curve as a fact base for global discussions about what levers exist to reduce GHG emissions, how to compare reduction opportunities and costs between countries and sectors, and how to discuss what incentives (e.g., subsidies, taxes, and CO_2 pricing) to put in place. For example, with this analysis, the question can be asked and answered, "If a government wanted to make different abatement measures happen, how much would different measures reduce emissions and what is the minimum cost (to achieve this emission reduction from a societal perspective)?"

All costs in the model are based on current cost and estimated projections. Estimates are based on best available projection methods, such as models (if available), expert views, and educated extrapolation. Given the long time horizon of approximately 25 years, a certain estimation error is inherent in the approach. Macroeconomic variables such as lifetime of assets, interest rates, oil prices, and exchange rates have the highest impact on results and error margins. Individual cost estimates per lever are of lower significance and will not substantially distort overall results for each lever.

Transaction costs – costs incurred in making an economic exchange above and beyond the technical project costs (e.g., education, policing, and enforcement costs) – are not included in the cost curve. Implementation cost for abatement levers are considered part of the transaction costs, involving such aspects as information campaigns and training programs.

Behavioral changes are also excluded from the cost curve, although they do present additional abatement potential. Behavioral changes are driven by various price and non-price factors, such as public education, awareness campaign, social trend, or policy changes. For this reason, behavioral shifts are analyzed separately from the primary cost curve as "further potential" with no abatement cost attached.

Scope and parameters of the analysis

The analysis in this study covers all known anthropogenic GHG emissions globally.

The base year for the is 2005, with emissions and abatements projected for the years 2010, 2015, 2020, 2025 and 2030.

The cost curve model analyzes 10 sectors bottom-up in detail, 3 with top-down estimates and covers the entire world dividing it into 21 regions/countries. The bottom-up covered sectors are: power and heat, petroleum and gas, cement, iron and steel, chemicals, road transport, buildings, forestry, agriculture, and waste. The top-down assessed sectors are: other industry, sea transport, air transport. The breakdown for regions/countries is: Brazil, Canada, China, France, Germany, India, Italy, Japan, Mexico, Russia, South Africa, United Kingdom, United States, Middle East, Rest of Latin America, Rest of EU27, Rest of OECD Europe, Rest of Eastern Europe, Rest of Africa, Rest of developing Asia, Rest of OECD Pacific.

Following IPCC definitions, the abatement cost curve shows technical measures with economic potential under € 60 per tCO_2e.

Four criteria are applied to include a new technology in the cost curve:

- The technology is at least in the pilot stage.
- There is a widely shared point of view on the lever's technical and commercial viability in the medium term (starting by 2025 at the latest) and would therefore represent a significant contribution to reductions by 2030.
- Technological and economical challenges are well understood.
- There are compelling forces supporting the technology, such as policy or industry support, tangible benefits (e.g., energy security), or expected attractive economics.

Technologies excluded from the analysis include among others biodiesel from algae, biokerosene, CCS with Enhanced Gas Recovery, biomass gasification in power generation, wave and tidal power, and HCCI (Homogeneous Charge Compression Ignition) and camless valve actuation.

Key assumptions in this analysis include:

- Societal interest rate of 4 percent per annum
- Prices and costs are 2005 real values
- Oil price of $ 60 per barrel (IEA WEO 2007)
- Regional GDP and population compound growth rates shown in Exhibit A.III.3

These growth rates are the underlying drivers for the baseline from the IEA and are used to project GDP growth, which we then use as the basis for our financial comparisons. However, no demand elasticity has been modeled (e.g., GDP is not linked to changes in our assumptions on energy prices).

Exhibit A.III.3

Macroeconomic data: regional real GDP and population growth rates
Annual growth rates, Percent

	GDP development		Population growth	
	2005–15	2015–30	2005–15	2015–30
North America	2.6	2.2	1.0	0.7
Western Europe	2.3	1.8	0.1	0.0
Eastern Europe*	4.7	2.9	-0.2	-0.3
OECD Pacific	2.2	1.6	0.1	-0.2
Latin America	3.8	2.8	1.2	0.9
Rest of developing Asia**	6.9	4.8	1.1	0.8
Africa	4.5	3.6	2.2	1.9
China	7.7	4.9	0.6	0.3
India	7.2	5.8	1.4	1.0
Middle East	4.9	3.4	2.0	1.5

* IEA nomenclature "Transition Economies"
** IEA nomenclature "Developing Asia"
Source: IEA WEO 2007

Appendix IV – Comparison of results with IPCC AR4

Power

<table>
<tr><th>Power</th><th>BAU baseline 2030 ($GtCO_2e$)</th><th>Abatement potential 2030 ($GtCO_2e$)</th><th>Explanation of key differences</th></tr>
<tr><td>IPCC AR4</td><td>• 15.8
• Source: IEA WEO 2004</td><td>• 2.4 / 3.6 / 4.7 (L/M/H) (Figure TS.27)</td><td rowspan="2">• Abatement from rooftop solar PV included in the Buildings sector in IPCC AR4, but in the Power sector in Global 2.0 (0.8 $GtCO_2e$ difference)
• Higher 2030 business as usual emissions in Global v2.0 than in IPCC AR4 (3 $GtCO_2e$ difference) – driven by an updated IEA projection – leads to higher abatement opportunities
• Global 2.0 includes early retirement of existing power plants as an implicit abatement lever (2 $GtCO_2e$ difference)
• Global 2.0 has higher growth expectations for selected technologies (0.5–1.0 $GtCO_2e$ difference).
• Total IPCC potential of 3.6 $GtCO_2e$ lower than sum of maximum potentials per technology (IPCC chapter 4, rationale: consolidation of all supply technologies and accounting for demand reduction effect). Comparison of maximum IPCC potential per technology with Global v2.0 gives an indication for overall difference:
– Similar maximum values expected for nuclear, geothermal, and hydro
– Global v2.0: substantially higher potential due to higher growth expectations for Solar CSP and Solar PV, Wind, and CCS
– IPCC: higher values for bioenergy and coal to gas shift. Lower values in Global v2.0 driven by the maximum renewable/nuclear growth scenario with cost based merit order logic, limiting potentials of coal to gas and bioenergy.
• Carbon intensity of power sector only differs by about 6% (IPCC: 500 tCO_2e/GWh, Global: 527 tCO_2e/GWh). This is therefore not the driver of substantial differences.</td></tr>
<tr><td>Global v2.0</td><td>• 18.7
• Source: IEA WEO 2007</td><td>• 10.0</td></tr>
</table>

Industry

Industry	**BAU baseline 2030** ($GtCO_2e$)	**Abatement potential 2030** ($GtCO_2e$)	Explanation of key differences
IPCC AR4	• 22.3 (A1B) and 16.3 (B2), both incl. indirect emissions • Petroleum and Gas: 1.4–2.9 • Cement: 3.8–6.4 • Iron and Steel: 1.8–4.2 • Chemicals (Ethylene and Ammonia): 0.6–1.0	• 2.4 / 3.6 / 4.7 (L/M/H) (Figure TS.27)	• Relative mitigation potential of 25% very similar in both studies • Smaller business as usual 2030 in IPCC AR4 report driven by lower production volume figures in some sectors (e.g. Iron and Steel) and exclusion of some electricity consuming sectors (e.g., fabrics, IT data centers). IPCC focuses in their "Other Industries" section on high GWP gas emitting industries • Abatement potential from waste recycling allocated to each industry sector by the IPCC, whereas in Global v2.0 it is covered in the waste sector (0.9 $GtCO_2e$ in total) • Subsector comparison: – **Petroleum:** Lower potential in IPCC mainly driven by lower baseline, possibly only refining (downstream) included in IPCC. Global v2.0 includes downstream, midstream and upstream – **Chemicals:** Lower potential in IPCC due to lower baseline, driven by scope definition differences (IPCC only ethylene and ammonia), and by production volume differences – **Cement:** Slightly lower production forecast in Global v2.0 vs. IPCC AR4. Mitigation potential of Global v2.0 is at the lower range of the IPCC range, due to a) lower production forecast, b) lower relative abatement potential (Global 2.0 30%, IPCC AR4 40%) – **Iron and steel:** Big differences in 2030 *production volume forecasts* (~2,500 Mt compared to ~1,100 Mt), leading to higher baseline and consequently higher abatement potential – **Other industry:** Comparison not possible. In Global 2.0 this category includes light manufacturing, aluminum, pulp and paper.
Global v2.0	• 29.1 (incl. indirect emissions) • Petroleum and Gas: 3.9 • Cement: 3.9 • Iron and Steel: 5.5 • Chemicals: 5.3 • Other industry: 10.5	• 7.3 • Petroleum and Gas: 1.1 • Cement: 1.0 • Iron and Steel: 1.5 • Chemicals: 2.0 • Other Industry: 1.7	

Transport

Road transport	**BAU baseline 2030** ($GtCO_2e$)	**Abatement potential 2030** ($GtCO_2e$)	Explanation of key differences
IPCC AR4	• 6.6 (WBCSD)	• 0.7–0.8 for LDVs • 0.6–1.5 for biofuels	• Commercial transport (MDVs/HDVs) not addressed by IPCC • Global v2.0 baseline higher than IPCC/WBCSD as new research foresees higher LDV growth in the developing world. • Higher LDV abatement potential in Global v2.0 due largely to the higher LDV growth expectation
Global v2.0	• 8.1 (McKinsey)	• 2.4 (1.6 for LDVs, 0.3 for MDVs HDVs, 0.5 for biofuels)	

Sea transport	BAU baseline 2030 ($GtCO_2e$)	Abatement potential 2030 ($GtCO_2e$)	Explanation of key differences
IPCC AR4	• 0.9 (WBCSD)	• n/a	• Different baseline sources • Abatement potential in Sea transport not assessed by the IPCC
Global v2.0	• 1.8 (IMO)	• 0.4	

Air transport	BAU baseline 2030 ($GtCO_2e$)	Abatement potential 2030 ($GtCO_2e$)	Explanation of key differences
IPCC AR4	• 1.4 (WBCSD)	• 0.3	• No major differences
Global v2.0	• 1.5 (ICAO)	• 0.4	

Buildings – Residential and Commercial

Buildings	BAU baseline 2030 ($GtCO_2e$)	Abatement potential 2030 ($GtCO_2e$)	Explanation of key differences
IPCC AR4	• 14.3 (range 11.4 to 15.6)	• 5.4 / 6.0 / 6.7 (L/M/H)	• Reductions relative to business as usual are similar (IPCC 42%, Global v2.0 35%) • Different sources for the business as usual emissions growth • Abatement from rooftop solar PV included in the Buildings sector in IPCC AR4, but in the Power sector in Global 2.0 (0.8 $GtCO_2e$). If accounted for in Buildings, v2.0 indicates lower emissions after abatement than IPCC
Global v2.0	• 12.6	• 3.5 (4.3 if accounting for rooftop Solar PV in the buildings sector)	

Waste

Waste	BAU baseline 2030 ($GtCO_2e$)	Abatement potential 2030 ($GtCO_2e$)	Explanation of key differences
IPCC AR4	• 1.6	• 0.4 / 0.7 / 1.0 (L/M/H)	• Abatement potential from waste recycling allocated to industry sector by the IPCC, whereas in Global v2.0 it is covered in the waste sector (0.9 $GtCO_2e$) • Baseline and abatement potential very similar after taking this effect into account
Global v2.0	• 1.7	• 1.5 (0.6 without waste recycling)	

Forestry

Buildings	**BAU baseline 2030** ($GtCO_2e$)	**Abatement potential 2030** ($GtCO_2e$)	**Explanation of key differences**
IPCC AR4	• *n/a (but explained by IPCC authors)*	• 1.3 / 2.8 / 4.2 (L/M/H bottom-up studies) • 13.8 (top-down models)	• *Global v2.0 abatement potential is in the middle of* the range between IPCC AR4 estimates from global top-down models and from the collection regional models. In IPCC AR4 chapter 9 the bottom-up numbers were selected as more representative of the real situation, but it is admitted by IPCC authors that the numbers are probably lower than what the economic potential is, because implementation barriers are included. Compared to IPCC bottom-up models the Global v2.0 baseline is slightly lower. • Global v2.0 substantially more conservative in afforestation, reforestation and forest management (2.8 vs. 9.8 $GtCO_2$) than IPCC AR4 top-down models, mostly due to conservative assumptions on land availability for afforestation activities • Global v2.0 shows higher potential for avoided deforestation (5.0 vs 4.0 $GtCO_2$) than IPCC AR4 top-down models, in line with higher baseline assumptions on deforestation
Global v2.0	• 7.2 (5.2 deforestation (Houghton revised), 2 from peat (IPCC AR4)	• 7.8	

Agriculture

Waste	**BAU baseline 2030** ($GtCO_2e$)	**Abatement potential 2030** ($GtCO_2e$)	**Explanation of key differences**
IPCC AR4	• 8.0 to 8.4	• 2.3 / 4.3 / 6.4 (L/M/H)	• No major differences
Global v2.0	• 7.9	• 4.6	

Appendix V – Summary result for 21 regions

The baseline emissions and the abatement potential for all 21 modeled regions are shown in Exhibit A.V.1. The reader should keep in mind that a key purpose of this global study is to achieve comparability across regions. Consequently, the same global sources for business-as-usual emissions were used for all regions and the same uniform methodology for structuring and quantifying abatement opportunities (however with regionally differing values). National abatement studies – such as the ones McKinsey has published for several of the world's largest economies – provide a much deeper view of the specifics of each respective country, and to a much larger extent rely on national baseline data and other national statistics. Also, in national studies additional levers are included, which are particularly relevant in that country. Consequently, baseline data and abatement potential can slightly differ between this global study and the national studies previously published by McKinsey.

Exhibit A.V.1

Country/region split – BAU emissions and abatement potential

$GtCO_2e$ per year

Region Cluster	Country/region	BAU Emissions 2005	BAU Emissions 2020	BAU Emissions 2030	Abatement potential 2020	Abatement potential 2030
North America	Canada	0.6	0.8	0.9	0.2	0.4
	United States*	6.8	7.7	8.3	2.0	4.7
Western Europe	France	0.5	0.6	0.6	0.1	0.3
	Germany	1.0	1.1	1.1	0.2	0.4
	Italy	0.6	0.6	0.6	0.1	0.2
	United Kingdom	0.6	0.6	0.6	0.1	0.2
	Rest of EU27	2.2	2.4	2.6	0.7	1.6
	Rest of OECD Europe	0.4	0.5	0.6	0.1	0.3
Eastern Europe	Russia	2.4	2.9	3.0	0.7	1.5
	Rest of Eastern Europe	0.7	0.9	0.9	0.2	0.5
OECD Pacific	Japan	1.3	1.5	1.4	0.3	0.6
	Rest of OECD Pacific	1.1	1.3	1.4	0.4	0.8
Latin America	Brazil	2.7	3.1	3.3	1.9	2.4
	Mexico	0.5	0.7	0.8	0.2	0.4
	Rest of Latin America	1.7	2.3	2.7	0.8	1.7
Rest of developing Asia	Rest of developing Asia	6.8	7.9	8.6	3.9	5.7
Africa	South Africa	0.4	0.6	0.7	0.2	0.5
	Rest of Africa	2.7	3.2	3.5	1.3	2.4
China	China	7.6	13.9	16.5	3.5	8.4
India	India	1.8	3.3	5.0	1.0	2.7
Middle East	Middle East	1.6	2.6	3.2	0.6	1.4
Global Air & Sea Transport	Global Air & Sea Transport	1.8	2.6	3.3	0.3	0.8
	Total	**45.9**	**61.2**	**69.9**	**18.9**	**38.0**

* Difference of 0.4 $GtCO_2e$ to 2005 baseline value of 7 2 $GtCO_2e$ reported in McKinsey's US cost curve report is due to accounting of air and sea transport emissions (accounted for at the global level in this report). Other differences impacting also 2020 and 2030 numbers are due to the fact that carbon sink effects in Forestry are not accounted for in the baseline in this report according to international policy principles. Also, the external baseline used for this report (IEA WEO 2007) has somewhat lower emission forecasts than the US report sources (EIA, DOE).

Source: Global GHG Abatement Cost Curve v2 0

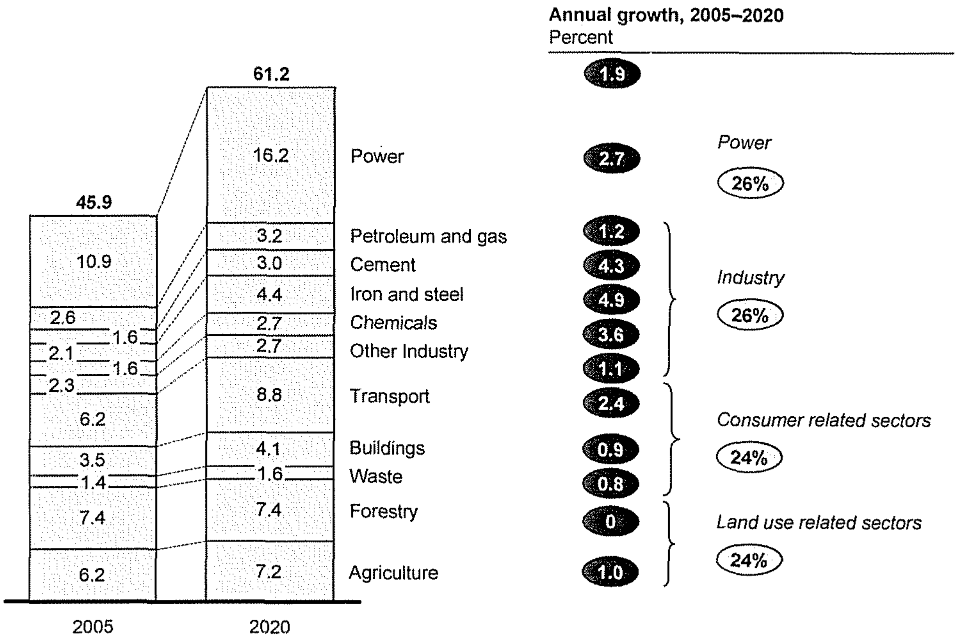
Appendix VI – Abatement results for 2020

For comprehensiveness, we included below the key results of our analysis for 2020. The business-as-usual developments per sector and region can be found on Exhibit A.VI.1 and Exhibit A.VI.2, respectively. The cost curve is shown on Exhibit A.VI.3. Abatement potentials per sector and region and the emissions per capita development are depicted on Exhibit A.VI.4, Exhibit A.VI.5, and Exhibit A.VI.6. Investment requirements per sector (Exhibit A.VI.7) and per region (Exhibit A.VI.8) complete the 2020 perspective

Exhibit A.VI.1

Business-as-usual emissions split by sector in 2005 and 2020

$GtCO_2e$ per year

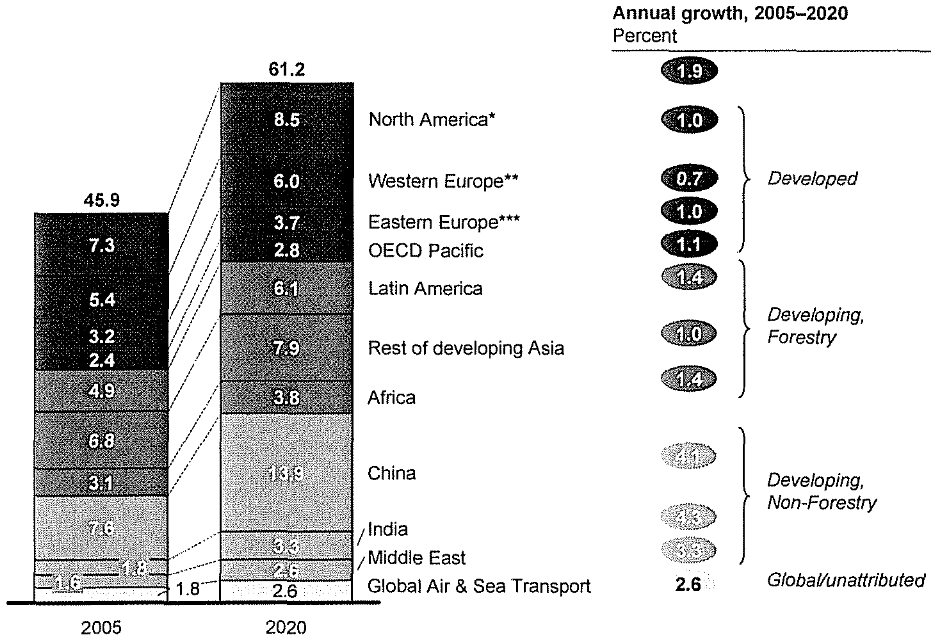


Source: Houghton; IEA; IPCC; UNFCCC; US EPA; Global GHG Abatement Cost Curve v2 0

Exhibit A.VI.2

Business-as-usual emissions split by region in 2005 and 2020

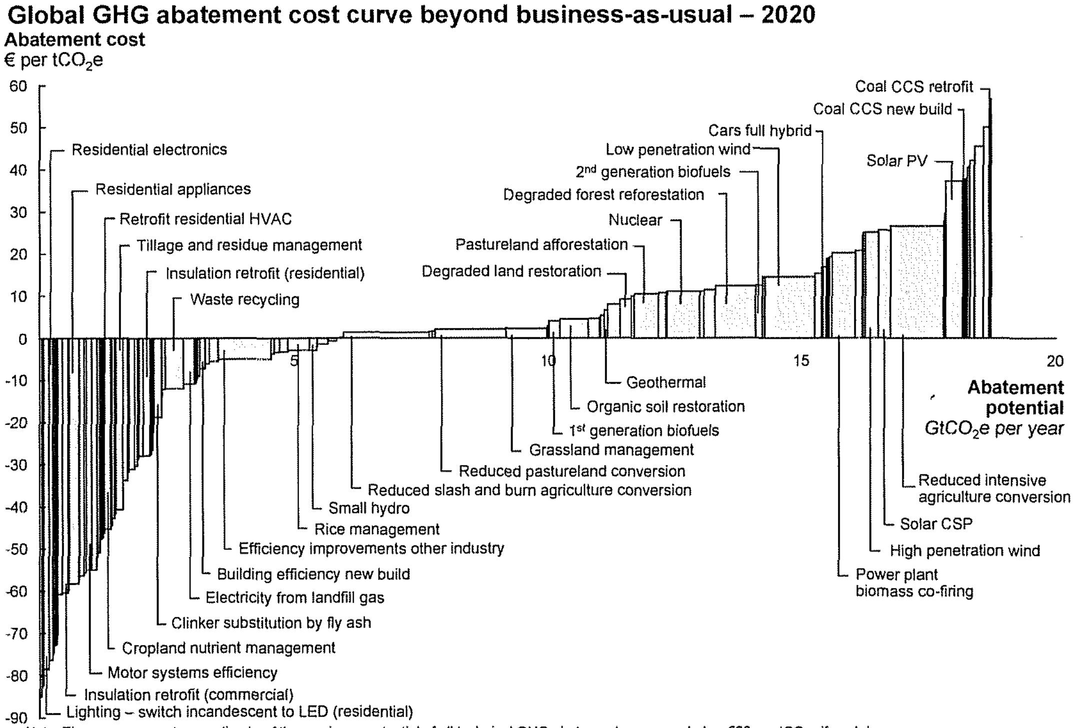
$GtCO_2e$ per year



* US and Canada
** EU27, Andorra, Iceland, Lichtenstein, Monaco, Norway, San Marino, and Switzerland
*** Non-OECD Eastern Europe and Russia.
Source: Houghton; IEA; IPCC; UNFCCC; US EPA; Global GHG Abatement Cost Curve v2.0

Exhibit A.VI.3

Global GHG abatement cost curve beyond business-as-usual – 2020



Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €60 per tCO_2e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play
Source: Global GHG Abatement Cost Curve v2.0

Exhibit A.VI.4

Sector split – BAU emissions and abatement potential

Indirect emissions and abatement potential

		2020 BAU $GtCO_2e$ per year		Abatement potential 2020 $GtCO_2e$ per year	Emissions reduction relative to 2020 BAU Percent	Emissions reduction relative to 2005 Percent
Power		16.2		3.4	-21	-6
Petroleum and gas	3.2	3.5	0.3	0.4	-12	2
Cement	3.0	3.4	0.5	0.5	-14	60
Iron and steel	4.4	5.1	0.1	0.5	-11	80
Chemicals	2.7	3.9	0.6	0.8	-20	30
Other industry	2.7	9.8	0.2	1.0	-11	34
Transport		8.8		1.1	-12	25
Buildings	4.1	12.1	0.6	1.6	-15	6
Waste		1.6		0.8	-47	-40
Forestry		7.4		5.9	-80	-80
Agriculture		7.2		2.9	-40	-31
Total		61		19	-31	-8

Power
~3 GtCO2e potential
-21% vs. 2030 BAU
-6% vs. 2005

Industrial sectors
~3 $GtCO_2e$ potential
-10 to -20% vs. 2030 BAU
+30 to +80% vs. 2005

Direct consumer related
~4 $GtCO_2e$ potential
-10 to -50% vs. 2030 BAU
-40 to +25% vs. 2005

Land use related
~9 $GtCO_2e$ potential
-40 to -80% vs. 2030 BAU
-30 to -80% vs. 2005

Source: Global GHG Abatement Cost Curve v2.0

Exhibit A.VI.5

Regional split – BAU emissions and abatement potential

	BAU emissions 2020 $GtCO_2e$ per year	Abatement potential 2020 $GtCO_2e$ per year	Emissions reduction relative to 2020 BAU Percent	Emissions reduction relative to 2005 Percent
North America*	8.5	2.1	-25	-13
Western Europe**	6.0	1.4	-24	-15
Eastern Europe***	3.7	0.9	-25	-13
OECD Pacific	2.8	0.7	-24	-11
Latin America	6.1	2.9	-47	-35
Rest of dev. Asia	7.9	3.9	-49	-41
Africa	3.8	1.5	-39	-25
China	13.9	3.5	-25	37
India	3.3	1.0	-31	31
Middle East	2.6	0.6	-22	26
Global air & sea travel	2.6	0.3	-12	29
Total	61	19	-31	-8

Developed regions
-20 to -25% vs. 2030 BAU
-10 to -15% vs. 2005

Developing regions, forestry
-35 to -50% vs. 2030 BAU
-25 to -45% vs. 2005

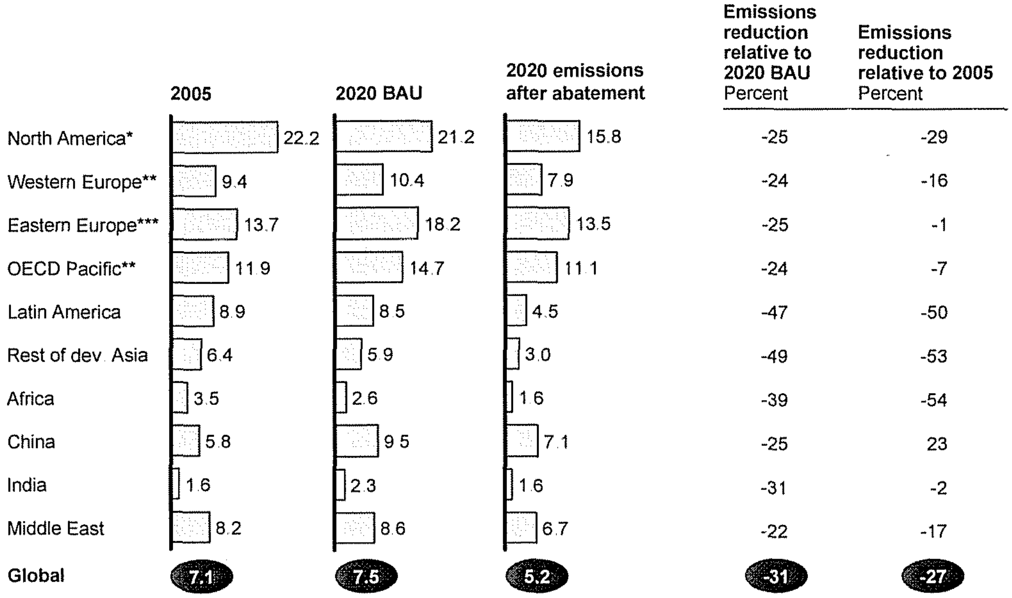
Developing regions, non forestry
-20 to -35% vs. 2030 BAU
+25 to +40% vs. 2005

* United States and Canada
** Includes EU27, Andorra, Iceland, Lichtenstein, Monaco, Norway, San Marino, Switzerland
*** Russia and non-OECD Eastern Europe
Source: Global GHG Abatement Cost Curve v2.0; Houghton; IEA; UNFCCC; US EPA

Exhibit A.VI.6

Emissions per capita development

tCO_2e per capita per year

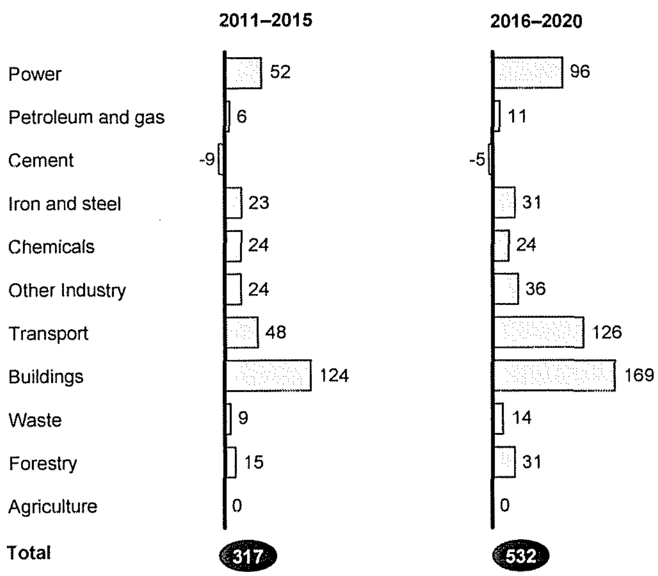


* United States and Canada
** Includes EU27, Andorra, Iceland, Lichtenstein, Monaco, Norway, San Marino, Switzerland
*** Russia and non-OECD Eastern Europe
Source: Global GHG Abatement Cost Curve v2.0; Houghton; IEA; UNFCCC; US EPA

Exhibit A.VI.7

Capital investment by sector incremental to business-as-usual for the abatement potential identified

€ billions per year; annual value in period

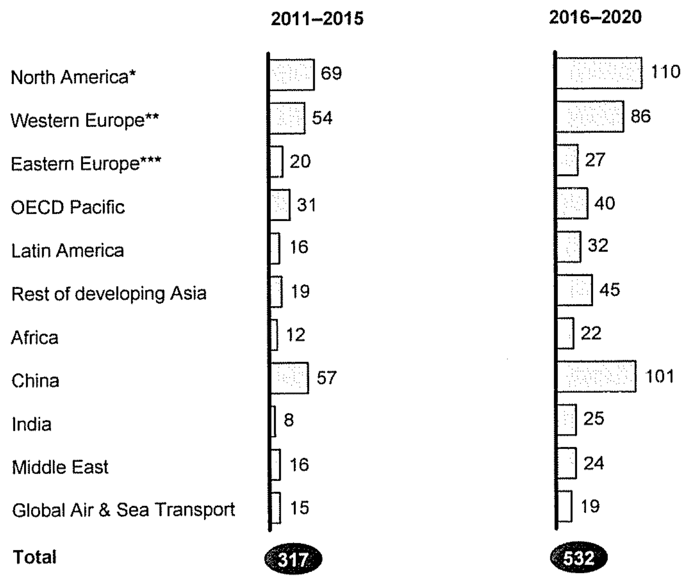


Source: Global GHG Abatement Cost Curve v2.0

Exhibit A.VI.8

Capital investment by region incremental to business-as-usual for the abatement potential identified

€ billions per year; annual value in period



* United States and Canada
** Includes EU27, Andorra, Iceland, Lichtenstein, Monaco, Norway, San Marino, Switzerland
*** Russia and non-OECD Eastern Europe
Source: Global GHG Abatement Cost Curve v2 0

Appendix VII – Assumptions by sector

For transparency, this appendix lists key assumptions for each abatement lever or group of abatement levers. For many assumptions, the uncertainty is considerable given the long time-lines involved, and the numbers quoted are the midpoint estimates used in our model.

Power

Lever	Key volume assumptions	Key cost and investment assumptions
Wind	• Volume growth constrained by two factors – Maximum wind production growth rate capped at 20% per year in any given region (few markets have consistently grown faster over 25 years) – Intermittent power sources (wind, solar PV) capped at 25% of production in any given region (wind 17–20%, solar 5–8%) • Wind energy natural potential assumed to not be a constraining factor	• Average 2005 capex of € 1,300 per kW • Overall cost per unit of electricity produced projected to decrease by ~5% with every doubling of cumulative installed capacity; these costs reductions reflect technology improvements but also decreasing resource quality with increasing penetration levels • Integration costs for low penetration case (<10% wind penetration) between € 2–3 per MWh depending on geography and power mix in balancing area. Integration cost for high penetration case includes additional load following, regulation reserves and grid extensions costs, increasing to € 3 to 5 per MWh at 20% penetration (based on recent NREL report)
Solar PV	• Global panel supply industry: Annual production capacity assumed at 28 GW in 2012; thereafter annual growth rates capped at 20% • Global production volume allocated to regions following radiation yield • Growth of regional installation markets capped at 20% per year (few markets have consistently grown faster over 25 years) • Intermittent power sources (wind, solar PV) capped at 25% of production in any given region (wind 17–20%, solar 5–8%)	• 2005 capex: € 3,500 per kW • Capacity driven learning rate at 18% for every doubling of cumulative installed capacity (>20% historically) • Capacity factor depending on region • Integration costs modelled at similar levels as for wind (no/very limited empirical data available)

Solar Concen-trated (CSP)	• Starting from very low installed base in 2005 to grow to a maximum potential 200 GW in 2030; industry growth 30% until 2015; 20% thereafter • Significant storage capabilities assumed; increasing to 16 hours after 2020 • All assumptions from DLR report (see reference section)	• Total capex at € 4,500–6,000 per kW in base configuration, decreasing with a learning rate of 10%. High costs for storage compensated by increase in full load hours and thus power production • Opex: decreasing from € 26.5 per MWh to € 14 per MWh in 2030 • Capacity factors depending on regional insolation and extent of storage facilities: 50—60% in 2020; increasing to 70–90% in 2030 with 16 hour storage (only deployed in regions with high insolation) • All assumptions from DLR report (see reference section)
Nuclear	• Maximum global installed base 750 GW in 2030, based on estimates by WNA, IAEA and McKinsey; growth limited by engineering, construction and supply chain capacity constraints • Regional split according to WNA assessment	• Due to limited experience with new construction and cost overruns in current projects, there is much uncertainty around capital costs for nuclear plants. Depending on the projects and the region, estimates range from € 1,500 to € 8,000 per kW. We assume a cost of € 3,000 per kW in 2005 in developed countries (€ 2,000 per kW is used for developing countries) • OpEx is estimated conservatively at € 22/kWh, including fuel costs and waste disposal, maintenance costs, insurance, liabilities and decommissioning costs
Geo-thermal	• Very high theoretical potential for power generation; arguably 500 GW (USGS) in US alone • US and developing Asia hold largest shares of current operating capacity, with about 30 percent each. Developing nations account for a large share of capacity planned or under construction • Potential 2030 capacity estimated at 60–80 GW, corresponding to IGA estimate for global potential of conventional geothermal energy (corresponds to 50 percent of potential of Enhanced Geothermal Systems (EGS))	• Capex: Average of € 3,000 per kW assumed (range from € 1,200 to 8,000 due to variations in local conditions) in 2005, with a capacity driven learning rate of 10% • Opex: € 13 per MWh (range from 8 to 18 due to variations in local conditions) • Capacity factor gradually increasing from 80% in 2005 to 90% in 2030 with technology improvements • Large uncertainty around cost development

CCS	• 50 plants assumed by 2020 (EU ambition of 12 plants extrapolated to global level) • After 2020, assumption that CCS technology has been proven on a large scale and that it will "take off": CCS manufacturing industry is assumed to be able to grow by 30 percent through 2030, potentially supplying up to 4.5 $GtCO_2e$ of abatement globally in the most aggressive case. Based on the model dynamics and the availability of plants, CCS ends up using 3.3–4.1 Gt of that potential across all sectors by 2030 (Power sector Scenario A and Scenario B respectively) • The Power sector shows the largest CCS potential (55 percent of the total) due to large point sources, availability of cheap fuel/electricity and suitable infrastructure	• High uncertainty on the cost side, as the technology has not yet been employed on such a large scale • Costs are assumed to decrease with different development stages; in an early stage in 2015, we assume €60–70/tonne from a "cost to society" perspective (i.e., a 4 percent interest rate). From a business perspective (e.g., a 15 percent interest rate), the corresponding costs are €70–80/tonne. In 2030, the cost for CCS in the Power sector is forecast at €30–45/tonne. Base capex for new-build coal-fired power plants equipped with CCS is €2,700–3,200/kW (assuming a 40-year lifespan) • Storage availability not assumed to be a significant bottleneck in the long term • CCS-equipped plants that can sell the CO_2 for enhanced oil recovery (EOR) have an additional revenue stream, assumed at €20/tonne
Biomass	• 10% biomass co-firing is assumed on 50% of coal plants • Volume of dedicated biomass plants in our model limited by total demand for new capacity in most geographic (as it is a higher cost option than many other low carbon technologies)	• Co-firing: biomass fuel cost and € 6 per kW in additional capex for minor modifications of fuel feed system • Dedicated biomass plants are with our methodology (looking up to € 60 per tonne CO_2e) most attractive when large scale and equipped with CCS (as CCS costs less than € 60 per tonne CO_2e) • Dedicated biomass capex: € 1,700 per kW (range from € 1,500 to 2,000 per kW) with learning rate of 5%; capacity factor is set to 80%, with a lifetime of 40 years
Small hydro	• Global 2030 potential of ~220 GW according to ESHA • Potential in developed countries largely exploited but still considerable potential in developing Asia (40–50% of total capacity in Asia by 2030)	• Large variation in capex due to natural preconditions. Average of € 2,000 per kW developed countries; € 1,250 per kW developing countries (ESHA) • Capacity factor is set to 35%
Shift of coal new builds to gas	• A share of the construction of new coal plants can be replaced by higher utilization of existing gas plants • We assume an increase to 50 percent utilization possible, to leave ample room for gas plants to act as peak plants and back-up capacity for intermittent energy sources	• Avoided capex cost for coal new builds assumed as savings; higher opex determined by spark spread in given period

Petroleum and Gas – Upstream Production and Processing

Lever	Description	Key volume assumptions	Key cost assumptions
Energy efficiency from improved behavior, maintenance and process control on retrofits	• Energy conservation awareness programs • Additional/improved maintenance that ensures equipment stays in optimal condition; i.e., monitoring and reduction of fouling (deposit build-up in the pipes) • Improved process control that reduces suboptimal performance i.e., due to undesired pressure drops across gas turbine air filters, an undesired turbine washout frequency, suboptimal well and separator pressures	• Due to low priority historically given to efficiency in upstream, abatement potential assumed equal to max. abatement in downstream (levers 1 & 2 combined) – EU: 9.0% – US: 10.6% – ROW: 9.4%	• Capex assumed equal to downstream in terms of cost per tCO_2e abated (16 M€ per $MtCO_2e$) • Savings based on (for all efficiency levers) – Reduced fuel consumption (natural gas and fuel oil) – Projected prices of fuels consumed
Energy efficiency from improved maintenance and process control	• Efficiency measures that involve replacement/ upgrades/additions that do not alter the process flow of an upstream production site • More efficient pump impeller • Replacement of boilers/ heaters/turbines/ motors	• Abatement potential assumed equal to minimum in downstream for lever 3 because of little opportunity for heat integration and more simple operations – EU: 4.1% – US: 6.5% – ROW: 5.9%	• Capex assumed equal to downstream in terms of M€ per $MtCO_2e$ abated (€495 million per $MtCO_2e$) • Opex estimated at 5% of total required Capex
More energy efficient new builds	• Program that ensures new built production sites use both process units with best-in-class energy efficiency as well as maintenance procedures and process controls that uphold the best-in-class energy efficiency	• Based on Energy Star Program and expert estimates, volume savings are estimated at – EU: 13.1% – US: 17.1% – ROW: 15.3%	• Capex assumed equal to 80% of total costs for levers 1 & 2 as improvements can be implemented 'first time right' (€ ~409 million per $MtCO_2e$) • Opex estimated at 5% of total required Capex
Reduction of continuous, remote flaring	• Measures to reduce continuous flaring by capturing the otherwise flared gas and bringing it to market, which will require – Gas recovery and treating units for oil associated gasses – Pipeline network to transport the gas	• Baseline flaring reduced by 72% between 2005–30 • Of remaining flares – 90% assumed to be large enough for a gathering system – 70% close enough for a transportation system • 95% of flaring is from continuous flaring	• Capex – € 320 million per BCM for the gathering system – 50 km pipe per flare @ $ 0.5 million per km • Average flare size of 2 mscf per day • Opex estimated at 15% of total required Capex • Savings result from reduced indirect electricity

Carbon Capture and Storage (CCS)	• Carbon capture and storage (CCS) is the sequestration of CO_2 from large emission *point sources*	• 80% of production sites assumed to be close enough to storage • CCS technically feasible in 80% of sites • 90% capture rate	• Capex € ~600 per tCO_2e annual abatement capacity decreasing to ~200 in 2030 • Energy cost dependent on fuel mix and electricity prices • Transport average 100 km @ 0.14 € per km decreasing to 0.10 in 2030 • € 11 per tCO_2e storage cost increasing to 12 by 2030 • Overhead cost 15 € per tCO_2e, decreasing to 6 € per tonne in 2030

Petroleum and Gas – Midstream Gas Transport and Storage

Lever	Description	Key volume assumptions	Key cost assumptions
Replace compressor seals	• Replacing traditional wet seals, which use high-pressure oil as a barrier against natural gas escaping from the compressor casing, with dry seals reduces methane leakage from compressors	• Based on Energy Star Program, Oil & Gas *Journal* and expert estimates, volume savings as percentage of total emissions are estimated at 82% of emissions from all dry seals which is – ~7% of transmission leakage emissions or – 2% of total emissions	• Capex – € 160,000/ compressor for dry seals – € 40,000/ compressor for wet seals • Opex – € 7,000/ compressor for dry seals – € 49,000/ compressor for wet seals
Improved maintenance on compressors	• A directed inspection and maintenance (DI&M) program is a means to detect, measure, prioritize, and repair equipment leaks to reduce methane emissions from compressors, valves, etc. – A DI&M program begins with a baseline survey to identify and quantify leaks. Repairs that are cost-effective to fix are then made to the leaking components – Subsequent surveys are based on data from previous surveys, allowing operators to concentrate on the components that are most likely to leak and are profitable to repair	• Also based on Energy Star – 15% leakage (not due to seals) worldwide is abated – This represents 3% of total emissions	• No Capex • Opex: € 133/ compressor

DIM on distribution network	• DIM program on the distribution network reduces leakage in a similar way as a DIM program on compressors but focuses on surface and metering stations	• Based on Energy Star Program and expert estimates – 80% of the gap between current practice and technical best practice can be reduced – Technical best practice is a 10% reduction of emissions in the region with current best practice – This represents 5% of total emissions	• No Capex • Opex: € 524,000/bcm (based on € 1,200 per kilometer of actively maintained pipe)
Improved planning	• Planning decreases emissions due to transmission combustion – Planning reduces unnecessary (de-) pressurization by actively matching compression needs with natural gas demand – In addition, emphasis is placed on running compressors at their most efficient point, called the working point	• Based on expert opinion – Assume 7% reduction in fuel consumption – This represents 2% of total emissions	• Capex: € 100,000/bcm • Opex: 15% of Capex

Petroleum and Gas – Downstream Refining

Lever	Description	Key volume assumptions	Key cost assumptions
Energy efficiency from behavioral changes	• Energy conservation awareness programs including – Energy and GHG awareness of personnel – A review energy and GHG management system including monitoring KPIs vs. targets – An energy management focus in all processes	• Based on Energy Star Program and expert estimates, abatement volume* is estimated at – EU: 2.5–3.0% – US: 2.9–3.5% – ROW: 2.6–3.1%	• No Opex or Capex required • Savings based on (for all efficiency levers) – Reduced fuel consumption – Projected prices of fuels consumed
Energy efficiency from improved maintenance and process control	• Additional/improved maintenance that ensures equipment stays in optimal condition; i.e., maintenance and monitoring of steam traps/steam distribution or monitoring and reduction of fouling (deposit build up in the pipes) • Improved process control that reduces suboptimal performance i.e., due to undesired pressure drops across gas turbine air filters, an undesired turbine washout frequency, suboptimal well and separator pressures	• Different abatement volume estimates depending on whether refineries have implemented major energy efficiency programs – EU: with 0.5–1.2%; without 2.5–6.0% – US: with 0.6–1.4%; without 2.9–7.1% – ROW: with 0.5–1.2%; without 2.6–6.2%	• Capex investment of USD 1 million required for a reference refinery (capacity of 180 MBBL/day) in a reference region (EU) • Capex scaled by volume and regional factors • Opex estimated at 15% of total required Capex
Energy efficiency requiring Capex at process unit level	• Efficiency measures that involve replacement/upgrades/additions that do not alter the process flow of a refinery – Waste heat recovery via heat integration – Replacement of boilers/heaters/turbines/motors	• Based on Energy Star Program and expert estimates, abatement volume* is estimated at – EU: 4.1–4.3% – US: 6.5–9.5% – ROW: 5.9%-9.7%	• Capex investment of USD 50 million required for a reference refinery (capacity of 180 MBBL/day) in a reference region (EU) • Capex scaled by volume and regional factors • Opex delta estimated at 5% of total required Capex

Co-generation	• Efficiency measure using Combined Heat and Power generation in which waste heat from power production is used in the refinery	• Co-generation capacity replaces 30% of thermal energy • 60% of refineries technically capable of installing cogeneration • Volume determined by the delta in carbon intensity between the of the power sector and co-generation	• Capex of 1 M€ per MW • Opex estimated at 5% of total required Capex • Co-generation assumed to run on natural gas • Savings result from reduced indirect electricity and reduced fuel consumption of standard fuels (e.g., fuel oil)
Carbon Capture and Storage (CCS)	• Applying Carbon Capture and Storage to – The exhaust emissions coming from direct energy use in the downstream refineries – The emissions coming from the hydrogen generation unit	• Refineries processing >100 MBBL per day are large enough • 80% of refineries assumed to be close enough to storage • CCS technically feasible in 80% of refineries • 90% capture rate	• Capex € ~600 per tCO_2e annual abatement capacity decreasing to ~200 in 2030 • Energy cost dependent on fuel mix and electricity prices • Transport average 100 km @ 0.14 € per km decreasing to 0.10 by 2030 • € 11 per t storage cost increasing to 12 by 2030 • Overhead cost € 15 per ton CO_2 abated, decreasing to € 6 per tonne in 2030

Cement

Lever	Description	Key volume assumptions	Key cost assumptions
Clinker replacement with fly ash	• Reducing the clinker content in cement, by substituting clinker with slag, fly ash, and other mineral industrial components, reduces process and fuel combustion emissions as well as electric power from clinker production, which together accounts for over 90% of total emissions from the Cement industry	• Max share of clinker replacement with fly ash assumed 25% • Used after all gypsum (5%) and available slag have been consumed	• Capex of 5 € per tonne for flyash handling capacity • Material cost of 4 € per tonne & 13.5 € per tonne freight • Minus avoided capex for clinker production capacity, electricity, fuel and clinker costs
Clinker replacement with slag	• As above	• Max share of clinker replacement with slag assumed 40% • Preferred filler to start with (after 5% gypsum have been subtracted as general share)	• Capex 70 € per tonne for slag granulation capacity and 75 € per tonne for slag grinding capacity • Material cost of 8 € per tonne and 13.5 € per tonne freight • Minus avoided clinker opex and capex
Clinker replacement with other MIC	• As above	• Max share of clinker replacement with other MIC assumed 10% • Unlimited availability assumed	• Capex of 60 € per tonne other MIC grinding capacity and 12 € per tonne handling capacity • Material costs of 1.5 € per tonne • Minus avoided clinker opex and capex
Increased share of waste as kiln fuel	• Burning alternative fuels, such as municipal or industrial fossil waste, or biomass instead of fossil fuels in the cement kiln to reduce average fuel combustion emissions of the clinker making process	• 2005 share set as RC, increased to 25% of energy required for clinker prod. 2030 globally • Combustion reduces CO_2e of alternative power use in incineration	• Capex of 200 € per tonne waste handling capacity • Fuel costs of 5 € per tonne waste & 7 € per tonne OH • Minus avoided costs for fossil fuels (differs by region based on fuel mix)
Increased share of biomass as kiln fuel	• Alternative fuels are assumed CO_2e neutral, based on a life-cycle perspective for biomass and alternative usage considerations for waste fuels	• 2005 share assumed as reference scenario • Increased to 8% of energy required for clinker production in 2030 globally	• Capex of 200 € per tonne waste handling capacity • Fuel costs of 20 € per tonne biomass & 7 € per tonne OH • Minus avoided costs for fossil fuels • (differs by region based on fuel mix)

<table>
<tr><td>Carbon Capture and Storage – newbuilds</td><td rowspan="2">• Carbon Capture and Storage (CCS) is the sequestration of CO_2 after it has been emitted due to fuel combustion and the clinker calcination process</td><td>• Implementation commencing in 2021
• Share of newbuild capacity 2021- 2025 assumed 13% and 2026–2030 assumed 37% on average per period</td><td rowspan="2">• Overhead cost € 15 per ton CO_2 abated, decreasing to € 6 per tonne in 2030
• Energy cost dependent on fuel mix and electricity prices
• CO_2 transport cost of 7 € per tonne CO_2 in 2030
• € 11 per tonne storage cost, increasing to € 12 per tonne in 2030
• Capex € ~600 per tonne new build CO_2 annual abatement capacity decreasing to € ~200 in 2030</td></tr>
<tr><td>Carbon Capture and Storage – retrofits</td><td>• Implementation commencing in 2026
• Share of retrofitted capacity assumed 4% for developing and 7% for developed countries on average between 2026–2030</td></tr>
<tr><td>Waste heat recovery</td><td>• Usage of excess heat from the clinker burning process for electricity generation using steam turbines driven by the flue gas exhaust stream</td><td>• 33% of clinker production capacity assumed to be equipped with waste heat recovery
• 15 KWh electricity generated per tonne clinker</td><td>• Capex of 12.9 € per tonne annual clinker capacity equipped
• Opex savings based on electricity cost</td></tr>
</table>

Additionally, it is important to note that we assume the *clinker share (clinker to cement ratio) in China to increase in the short term* due to changes in product mix from 74% in 2005 to 78% in 2030 – this has significant effect on the short term as China produces 46% of cement globally in 2005. In the abatement case China will reach a level of 62% in clinker share in 2030.

Iron and Steel

Lever	Description	Key volume assumptions	Key cost assumptions
Co-generation	• Blast Furnace/Basic Oxygen Furnace (BF/BOF) steel-manufacturing process generates gas as a by-product • This gas can be recovered, cleaned and used for power generation • Cogeneration can be integrated in the BF/BOF steel-manufacturing process to reduce the total energy demand	• All indirect energy in BF/BOF plants can be generated internally, allowing them to literally cut the power cord	• Capex of € ~70 per tonne steel production capacity • 4 % interest rate (all levers) • No opex cost delta • Savings based on indirect energy prices (Power)
Direct casting	• Direct casting is a technique that integrates the casting and hot rolling of steel into one step, thereby reducing the need for reheat before rolling • Near net-shape casting and strip casting are two newly developed direct casting techniques	• ~18% reduction in after treatment energy intensity • Only applicable to new build	• Capex of € ~80 per tonne steel annual after treatment capacity, no opex cost delta • Savings based on direct energy prices for fuel mix used in steel after treatment
Smelt reduction	• Smelt reduction is a technique that avoids the coking process by combining upstream hot metal production processes in one step • The emission savings are achieved as less direct fuel is used when integrating preparation of coke with iron-ore reduction	• ~8% reduction of BF/BOF direct energy intensity	• Capex of € ~100 per tonne steel annual production capacity, no opex cost delta • Savings based on direct energy cost for fuel mix used in direct BF/BOF plants

Energy efficiency	• Annual improvement in direct energy efficiency above reference case, caused by a number *of individual levers:* Structural shift from BF/ BOF to EAF production, better preventative maintenance, Improved process flow (management, logistics, IT-systems), motor systems, New efficient burners, Pumping systems, Capacity utilization management, Heat recovery, Sinter plant heat recovery, Coal moisture control, Pulverized coal injection	• 0.2–0.4% p.a. general energy efficiency increase above reference case (EE I), 0.2 % *efficiency* increase (EE II) • Different improvement rates in EE I due to converging energy efficiencies globally	• Modeled as a net capex delta of € 25 or € 45 per tonne, respectively, abated CO_2e, no opex cost
CCS	• Carbon capture and storage (CCS) is the sequestration of CO_2 from large emission point sources • Capture is modeled as post combustion, with chemical reactions “cleaning” the exhaust gases of CO_2	• 90% capture rate, 90% of plants reaching enough scale • 80% within reach of storage sites • 0.24 MWh energy increase per tonne CO_2 separated in 2030 • 80% of old plants retrofittable due to technical constraints • Implementation commencing in 2021	• Overhead cost € 15 per tonne CO_2 abated, decreasing to € 6/ tonne in 2030 (€ 19 and € 8 per tonne for retrofit) • Transport average € 7 per tonne in 2030 • € 11 per tonne storage cost, increasing to € 12 per tonne 2030 • Capex € ~600 per tonne new build CO_2 annual abatement capacity decreasing to € ~200 in 2030
Coke substitution	• Substituting coke used in BF/BOF furnaces with fuel based on biomass, with zero carbon intensity	• ~10% of coke possible to substitute • ~100% carbon intensity decrease from carbon neutral biomass • No substitution in reference case • 100 % *implementation* by 2030	• No capex required for fuel shift • Savings based on indirect fuel price deltas for BF/BOF mills
BF/BOF to EAF-DRI shift	• Increased share of EAF-DRI relative BF/BOF in future steel making • Direct Reduced Iron can be produced with natural gas as ore reducing agent. This DRI is used in EAF, replacing scrap. This replaces the reduction of iron ore with coke in BF/ BOF process.	• Delta of BF/BOF and EAF-DRI carbon intensities driving abatement volume • 10 % of BF/BOF steel production volume • shifted by 2030 • No technology shift in reference case	• Capex difference of € ~200 per tonne steel annual production capacity • No opex cost delta • Opex savings or cost based on indirect energy prices

Chemicals

Lever	Description	Key volume assumptions	Key cost assumptions
Motor systems	• Introduction of energy saving measures in motor systems, such as adjustable speed drive, more energy efficient motors, and mechanical system optimization	• ~25% savings in indirect energy compared to standard systems • 30 % implementation in RC, 100 % in AS by 2030	• Capex of € ~50 per MWh installed base* • No overhead cost delta • Opex based on energy savings
Adipic acid	• Decomposition of the green house gas N_2O (produced in the process of making adipic acid) into oxygen and nitrogen through the use of catalysts	• ~80–90% capture rate of N_2O without lever (regional) • 98 % capture with lever • 10% in RC, 100% in AS by 2030	• Capex of € ~10 per tonne acid (new build) • Opex of € ~20 per tonne acid • No significant energy delta
Nitric acid	• Applying filtering measures in order to decompose N_2O from the tailgas of nitric acid production, where N_2O is produced as a process emission	• ~7–9 tonne of N_2O per Mtonne acid without lever (regional) • ~1 ton of N_2O per Mton acid with lever • Not implemented in reference case, 100% in AS by 2030	• Capex of € ~10 per ton acid • Opex of € ~10 per ton acid • No significant energy delta
Fuel shift	• Shifting direct energy use from coal powered systems to biomass powered systems, and oil powered systems to gas power, thereby lowering the carbon intensity per MWh energy produced given the lower carbon intensity of gas and biomass	• Biomass not part of RC, 80 % in AS new build, 50 % retrofit • Gas not part of RC, 80 % in AS new build, 50% retrofit • CO_2e abatement based on combustion emissions by fuel	• Capex of € ~5 per MWh installed • Opex based on difference of fuel prices • No significant overhead costs assumed
CCS Ammonia	• Introduction of Carbon Capture and Storage to the $CO2_2$ emitted as a process emission from Ammonia production	• 90% capture rate, 90% of plants reaching enough scale • 80% within reach of storage sites • 0.24 MWh energy increase per ton CO_2 separated in 2030 (0.15 for ammonia separation) • 80% of old plants retrofittable • Implementation commencing in 2021	• Overhead cost € 15 per ton CO_2 abated, decreasing to € 6 per tonne in 2030 (€ 19 and € 8 per tonne for retrofit) • Transport average € 7 per tonne in 2030 • € 11 per tonne storage cost, increasing to € 12 per tonne in 2030 • Capex € ~600 per tonne new build CO_2 annual abatement capacity decreasing to € ~200 in 2030
CCS Direct	• Applying Carbon Capture and Storage to the exhaust emissions coming from direct energy use in the chemical plants		

Process intensification	• Process intensification in chemical processes, leading to an annual emission decrease. The improvements are caused by a number of individual levers, including continuous processes, improved process control, preventative maintenance, more efficient burners and heaters and logistical improvements	• 0.1–0.25% p.a. process intensification and catalyst optimization above RC • Different improvement rates regionally due to converging energy efficiencies globally • Modeled in three steps, with increasing costs • Both levers split in two buckets: "process "and "energy", affecting the corresponding emission type in baseline	• Capex modeled as the net delta per tCO$_2$e annual abatement potential in three steps, € 0, ~200, and ~400 per tonne • Opex modeled as net opex delta per abated tCO$_2$e in similar steps @ € 0, 10, and 20 per tCO$_2$e
Catalyst optimization	• Catalyst optimization in chemical processes, leading to an annual process and direct energy emissions decrease above the reference case. The improvements are caused by a number of individual levers, including improved chemical structure of catalysts, design to lower reaction temperatures, and chain reaction improvements		
CHP	• CHP, combined heat and power, is a technique to involve the energy losses in power production to generate heat for processes, in order to increase system efficiency and decrease the amount of fuel needed for power generation	• 15% savings in direct power (regional) compared to heating systems without CHP • 0% implementation in RC, 100 % in abatement case by 2030	• Capex of € ~55 per MWh existing direct power in a given plant • Opex based on fuel savings
Ethylene cracking	• Ethylene Cracking improvement includes furnace upgrades, better cracking tube materials and improved separation and compression techniques that lowers the direct energy used in the cracking process	• ~1.1 MWh savings per ton Ethylene compared to standard cracking processes • 0% implementation in RC, 100 % in abatement case by 2030	• Capex of € ~50 per tonne Ethylene production • Overhead cost of € ~25 per tonne Ethylene • Opex largely driven by energy savings (1.1 MWh per tonne)

Transport/LDVs: gasoline, diesel

Lever		Description	Key volume assumptions	Key cost assumptions Initial cost	Reduced cost 2030
ICE fuel efficiency improvments – gasoline	**Bundle G1**	• Variable valve control • Engine friction reduction (mild) • Low rolling resistance tires • Tire pressure monitoring system • Mild weight reduction	• ICE World scenario: 21% in 2011–2015, 21% in 2016–2020, 2% in 2021–2025 • Mixed Tech scenario: 20% in 2011–2015, 20% in 2016–2020, 1% in 2021–2025 • Hybrid/Electric World scenario: 20% in 2011–2015, 20% in 2016–2020, 1% in 2021–2025	€ 307 (2010)	€ 185
	Bundle G2	• Bundle G1+ • Medium displacement reduction ("downsizing") • Medium weight reduction • Electrification (steering, pumps) • Optimized gearbox ratio • Improved aerodynamic efficiency • Start-stop	• ICE World scenario: 18% in 2011–2015, 24% in 2016–2020, 9% 2021–2025, 3% 2026–2030 • Mixed Tech scenario: 17% in 2011–2015, 22% in 2016–2020, 7% 2021–2025, 2% 2026–2030 • Hybrid/Electric World scenario: 17% in 2011–2015, 21% in 2016–2020, 6% 2021–2025, 1% 2026–2030	€ 1,116 (2010)	€ 673
	Bundle G3	• Bundle G2+ • Strong displacement reduction ("downsizing") • Air conditioning modification • Improved aerodynamic efficiency • Start-stop system with regenerative braking	• ICE World scenario: 8% in 2011–2015, 35% in 2016–2020, 35% 2021–2025, 6% 2026–2030 • Mixed Tech scenario: 7% in 2011–2015, 30% in 2016–2020,27% 2021–2025, 4% 2026–2030 • Hybrid/Electric scenario: 7% in 2011–2015, 22% in 2016–2020, 24% 2021–2025, 3% 2026–2030	€ 1,794 (2010)	€ 1,081
	Bundle G4	• Bundle G3+ • Direct injection (homogeneous) • Strong weight reduction (9%) • Optimized transmission (including dual clutch, piloted gearbox)	• ICE World scenario: 0% in 2011–2015, 14% in 2016–2020, 54% 2021–2025, 90% 2026–2030 • Mixed Tech scenario: 0% in 2011–2015, 12% in 2016–2020, 37% 2021–2025, 54% 2026–2030 • Hybrid/Electric scenario: 0% in 2011–2015, 10% in 2016–2020, 29% 2021–2025, 38% 2026–2030	€ 2,593 (2010)	€ 1,563
Gasoline – Full hybrid		• Bundle G4 + Full hybrid	• ICE World scenario: 1% in 2011–2030 • Mixed Tech scenario: 3% in 2011–2015, 8% in 2016–2020, 16% 2021–2025, 22% 2026–2030 • Hybrid/Electric scenario: 1% in 2011–2015, 11% in 2016–2020, 21% 2021–2025, 25% 2026–2030	€ 3,498 (2010)	€ 1,848

Gasoline – Plug-in hybrid		• 60 km range – 66% electric share; • Energy demand electric drive 250 Wh per km	• ICE World scenario: 0% in 2011–2030 • Mixed Tech scenario: 0% in 2011–2015, 3% in 2016–2020, 11% 2021–2025, 17% 2026–2030 • Hybrid/Electric scenario: 1% in 2011–2015, 4% in 2016–2020, 15% 2021–2025, 24% 2026-	€ 12,217 (2010)	€ 3,530
Electric vehicle		• 200 km range • Energy demand 250 Wh/km	• ICE World scenario: 0% in 2011–2030 • Mixed Tech scenario: 0% in 2011–2015, 1% in 2016–2020, 1% 2021–2025, 2% 2026–2030 • Hybrid/Electric scenario: 1% in 2011–2015, 2% in 2016–2020, 5% 2021–2025, 9% 2026-	€ 26,336 (2010)	€ 5,764
ICE fuel efficiency improvement – Diesel	**Bundle D1**	• Medium downsizing • Engine friction reduction • Low rolling resistance tires • Tire pressure monitoring system • Mild weight reduction (1.0%)	• ICE World scenario: 21% in 2011–2015, 20% in 2016–2020, 3% 2021–2025 • Mixed Tech scenario: 20% in 2011–2015, 19% in 2016–2020, 3% 2021–2025 • Hybrid/Electric World scenario: 23% in 2011–2015, 19% in 2016–2020, 3% 2021–2025	€ 1,084 (2006)	€ 899
	Bundle D2	• Bundle D1 + • Piezo injectors • Medium downsizing • Medium weight reduction • Electrification (steering, pumps) • Optimized gearbox ratio • Improved aerodynamic efficiency	• ICE World scenario: 21% in 2011–2015, 29% in 2016-2020, 14% in 2021–2025, 5% in 2026–2030 • Mixed Tech scenario: 20% in 2011–2015, 27% in 2016–2020, 11% 2021–2025, 4% 2025–2030 • Hybrid/Electric World scenario: 22% in 2011–2015, 27% in 2016–2020, 10% 2021-2025, 4% 2025–2030	€ 1,396 (2006)	€ 1,087
	Bundle D3	• Bundle D2 + • Torque oriented boost • Air conditioning modification • Improved aerodynamic efficiency • Start-stop system with regenerative braking	• ICE World scenario: 8% in 2011–2015, 29% in 2016–2020, 34% in 2021–2025, 13% in 2026–2030 • Mixed Tech scenario: 7% in 2011–2015, 25% in 2016–2020, 27% in 2021–2025, 9% in 2026–2030 • Hybrid/Electric scenario: 7% in 2011–2015, 23% in 2016–2020, 24% 2021–2025, 9% in 2026-	€ 1,984 (2006)	€ 1,441
	Bundle D4	• Bundle D3 + • Increase injection pressure • Strong downsizing (instead of medium downsizing) • Strong weight reduction	• ICE World scenario: 0% in 2011–2015, 16% in 2016–2020, 46% 2021–2025, 80% in 2026–2030 • Mixed Tech scenario: 0% in 2011–2015, 13% in 2016–2020, 34% in 2021–2025, 56% in 2026–2030 • Hybrid/Electric scenario: 0% in 2011–2015, 11% 2016–2020, 31% 2021–2025, 46% in 2026–2030	€ 2,349 (2006)	€ 1,661

Diesel – Full hybrid	• Bundle D4 + Full hybrid	• ICE World scenario: 0% in 2011–2030 • Mixed Tech scenario: 3% in 2011–2015, 8% in 2016–2020, 15% in 2021–2025, 20% in 2025–2030 • Hybrid/Electric scenario: 0% in 2011–2015, 8% 2016–2020, 18% in 2021–2025, 23% 2026-	€ 4,962 (2010)	€ 2,512
Diesel – Plug-in hybrid	• 60 km range – 66% electric share • Energy demand electric drive 250 Wh per km	• ICE World scenario: 0% in 2011–2030 • Mixed Tech scenario: 0% in 2011–2015, 3% in 2016–2020, 8% 2021–2025, 10% 2025–2030 • Hybrid/Electric scenario: 0% in 2011–2015, 5% in 2016–2020, 13% 2021–2025, 18% 2026–2030	€ 12,217 (2010)	€ 3,530
CNG vehicle	• Fuel economy 2.92–4.43 litres natural gas per 100 km • Combustion emissions 1,740 g CO_2e per l natural gas • Energy content 31.6 MJ per l natural gas	• ICE World scenario: 0% in 2011–2030 • Mixed Tech scenario: 0% in 2011–2030 • Hybrid/Electric scenario: 0% in 2011–2015, 0% 2016–2020, 1% in 2021–2025, 1% 2026–2030	€ 4,274 (2010)	€ 2,576

Transport/MDVs

Lever		Description	Key volume assumptions	Key cost assumptions Initial cost	Reduced cost 2030
MDV ICE fuel efficiency improvements	**Bundle 1**	• Rolling resistance reduction	• 30% in 2011–2015 • 10% in 2016–2020 • 0% in 2030-	€ 637 (2008)	€ 637
	Bundle 2	• Rolling resistance reduction • Aerodynamics improvement	• 30% in 2011–2015 • 10% in 2016–2020 • 0% in 2021–2030	€ 637 (2008)	€ 1,273
	Bundle 3	• Rolling resistance reduction • Conventional ICE improvement incl. mild hybrid	• 20% in 2011–2015 • 40% in 2016–2020 • 50% in 2021–2030	€ 5,943 (2008)	€ 2,759
	Bundle 4	• Rolling resistance reduction • Aerodynamics improvement • Conventional ICE improvement incl. mild hybrid	• 20% in 2011–2015 • 40% in 2016–2020 • 50% in 2021–2030	€ 5,943 (2008)	€ 3,396
Full hybrid (not in cost curve)		• Rolling resistance reduction • Aerodynamics improvement • Conventional ICE improvement incl. mild hybrid • Full hybrid technology	• Not in cost curve	€ 48,391 (2008)	€ 24,620
Plug-in hybrid (not in cost curve)		• Rolling resistance reduction • Aerodynamics improvement • Conventional ICE improvement incl. mild hybrid • Full hybrid technology • Plug-in hybrid technology	• Not in cost curve	€ 68,281 (2008)	€ 44,510

Transport/HDVs

Lever		Description	Key volume assumptions	Key cost assumptions Initial cost	Reduced cost 2030
HDV ICE fuel efficiency improvements	**Bundle 1**	• Rolling resistance reduction	• 30% in 2011–2015 • 6% in 2016–2020 • 0% in 2021–2030	€ 2,122 (2010)	€ 2,122
	Bundle 2	• Rolling resistance reduction • Aerodynamics improvement	• 30% in 2011–2015 • 14% in 2016–2020 • 0% in 2021–2030	€ 2,441 (2010)	€ 3,714
	Bundle 3	• Rolling resistance reduction • Conventional ICE improvement incl. mild hybrid	• 20% in 2011–2015 • 24% in 2016–2020 • 25% in 2021–2025 • 20% in 2026–2030	€ 12,734 (2010)	€ 7,428
	Bundle 4	• Rolling resistance reduction • Aerodynamics improvement • Conventional ICE improvement incl. mild hybrid	• 20% in 2011–2015 • 56% in 2016–2020 • 75% in 2021–2025 • 80% in 2026–2030	€ 13,053 (2010)	€ 9,020
Full hybrid (not in cost curve)		• Rolling resistance reduction • Aerodynamics improvement • Conventional ICE improvement incl. .mild hybrid • Full hybrid technology	• Not in cost curve	€ 55,501 (2010)	€ 40,856

Transport Biofuels

1st Gen. Biofuels	• Modeled as sugarcane ethanol (26 gCO_2e per MJ)	• Gasoline biofuel volume: 5.75% in BAU, 25% in abatement case (14.5% 1st generation biofuels (4% corn/maize, 10.5% sugarcane), 10.5% 2nd generation biofuels (lignocellulosic)) • Diesel: 3.3% in BAU, 3.3% in abatement case	$ 1.30 per gallon	$ 1.30 per gallon
2nd Gen. Biofuels	• Modeled as ligno-cellulosic ethanol (25 gCO_2e per MJ)		–	$ 1.38 per gallon

Buildings – Residential

Lever	Description	Key volume assumptions	Key cost assumptions
New build efficiency package (incl. insulation)	• Achieve energy consumption levels comparable to passive housing – Reduce demand for energy consumption through improved building design and orientation – Improve building insulation and airtightness; improve materials and construction of walls, roof, floor, and windows – Ensure usage of high efficiency HVAC and water heating systems	• Assume that maximum site energy consumption for HVAC and water heating in new builds is 132 kWh per m^2 • New technology results in 20 kWh per m^2 in developing warm countries, 30 kWh per m^2 in developing cold countries, and 35 kWh per m^2 in developed countries (SITE energy)	• In 2005, 6-7% cost premium on new builds • By 2020: – Developing regions 5% cost premium on new builds with "high efficiency package." – 4% premium in developed regions • US initial construction costs validated with experts, and scaled to global regions
Insulation retrofit building package, level 1 and level 2	• Level 1 retrofit - "basic retrofit" package – Improve building airtightness by sealing baseboards and other areas of air leakage – Weather strip doors and windows – Insulate attic and wall cavities – Add basic mechanical ventilation system to ensure air quality • Level 2 retrofit – Retrofit to "passive" standard, in conjunction with regular building renovations – Install high efficiency windows and doors; increase outer wall, roof, and basement ceiling insulation; mechanical ventilation with heat recovery, basic passive solar principles	• Level 1 retrofit based on 15-25% heating savings potential and up to 10% cooling savings potential, adjusted by income and climate • Level 2 retrofit can reach heating/cooling consumption of 20-35 kWh per m^2 (SITE energy)	• Level 1 retrofit based on 6.26 € per m^2 in W. Europe / Japan. Scaled down to other countries by GDP • Cost of level 2 retrofit is 78 € per m^2 in 2005 and 50 € per m^2 in 2030 in Europe, scaled down by geography

Retrofit HVAC, residential	• When current gas/ oil furnaces or boilers expire, replace with the highest efficiency model, with AFUE (annual fuel utilization efficiency) rating above 95 • In appropriate climates, replace electric furnace with high efficiency electric heat pump • When current air conditioning unit expires, replace with highest efficiency model (16 SEER or above) • Reduce energy consumption from HVAC and AC through improved maintenance – Improve duct insulation to reduce air leakage and proper channeling of heated and cooled air – Ensure HVAC system is properly maintained, with correct level of refrigerant and new air filters	• For standard gas/ oil heaters, assume up to 19% savings potential from improved technology and proper sizing • For electric heat pump, assume up to 50% savings potential compared to electric resistance heating. Savings is slightly lower in extreme climates • For HVAC maintenance, assume total 15% savings from proper duct insulation and proper maintenance	• Assume 500 € premium for high efficiency gas/ oil model that covers 150 m^2 house; assume 2000 € premium for HE heat pump model that covers 150 m^2 house • Assume 500 € premium for HE AC system • Assume duct insulation/ maintenance job costs 635 € (aggressive cost estimate) to cover 150 m^2 house
Retrofit water heating systems	• When existing standard gas water heaters expire, replace with solar water heater, or with tankless/ condensing models • When existing electric water heater expires, replace with solar water heater or electric heat pumps	• In developing countries, maximum solar capacity is installed by 2030. In developed countries, aim for 10% solar penetration, with remainder using most efficient technology (heat pump or HE gas)	• Solar water prices drop at 2.3% CAGR, based on historic improvement form 1984-2004
New and retrofit lighting systems	• Replace incandescent bulbs with LEDs • Replace CFLs with LEDs	• lumen/W varies by technology: – Incandescent: 12 – CFL: 60 – LED: 75 in 2010; 150 by 2015 • In abatement case, assume full remaining share of incandescents switch to LEDs, and full remaining share of CFLs switch to LEDs	• Learning rate for LEDs based on historic 18% improvement in solar cell technology

New and "*retrofit*" appliances and electronics	• Purchase high-efficiency consumer electronics (e.g., PC, TV, VCR/ DVD, home audio, set-top box, external power, charging supplies) instead of standard items • When refrigerator/ freezer, washer / dryer, dishwasher, and fan expires, replace with high efficiency model	• HE consumer electronics use up to 38% less energy • Package of certified appliances in developed countries consume ~35% less energy	• Electronics: 34 € price premium for small devices • Appliances: price differential is 3-10% for HE devices

Buildings – Commercial

Lever	Description	Key volume assumptions	Key cost assumptions
New build efficiency package (incl. insulation)	• Reduce demand for energy consumption through improved building design and orientation • Improve building insulation and airtightness; improve materials and construction of walls, roof, floor, and windows • Ensure usage of high efficiency HVAC and water heating systems	• 61% savings potential on HVAC and water heating for new builds using "maximum technology"	• In developing regions, 5% cost premium on new builds with "high efficiency package." 4% premium in developed regions
Insulation retrofit building envelope	• Level 1 retrofit - "basic retrofit" package – Improve building airtightness by sealing areas of potential air leakage – Weather strip doors and windows	• Assume 48% savings potential in cold areas, and 11% savings potential in warm areas	• Level 1 retrofit is 4.10 € per m^2 in W. Europe/ Japan. Scaled down to other countries based on GDP
Retrofit HVAC and HVAC controls	• When HVAC system expires, install highest efficiency system • Improve HVAC control systems to adjust for building occupancy and minimize re-cooling of air	• HVAC system retrofit: assume similar savings potential compared to residential (~15%) • HVAC controls: 10-20% savings potential	• 500 € premium for every 5 tonnes (~17,000 W) of capacity installed • 5,000 € cost for retrofit control system in 1,700 m^2 building in developed countries
Retrofit water heating systems	• When existing standard gas water heaters expire, replace with tankless gas, condensing gas, or solar water heater • When existing electric water heater expires, replace with heat pump or solar water heater	• Assume that maximum solar capacity is installed by 2030 • No fuel shift, but shift to most efficient technology within fuel type (condensing gas or electric heat pump)	• Solar water heater learning rate based on 18% improvement in solar technology from 1950-2000

New and retrofit lighting systems	• Replace incandescent bulbs with LEDs • Replace CFLs with LEDs • Replace inefficient T12s/ T8s with new super T8s and T5s • New build – install lighting control systems (dimmable ballasts, photo-sensors to optimize light for occupants in room) • Retrofit – install lighting control systems (dimmable ballasts, photo-sensors to optimize light for occupants in room)	• In abatement case, assume full remaining share of incandescents switch to LEDS, and full remaining share of CFLs switch to LEDs • Assume maximum switch from old T12 and T8s to new T8/T5s • For lighting control systems – Achieve 50% savings potential in new build – Assume 29% savings potential in retrofit	• Learning rate for LEDs based on historic 18% improvement in solar cell technology • Cost of labor and materials for new build 3.42 € per m^2. Cost for retrofit is 10.93 € per m^2
New and "retrofit" appliances and electronics	• When existing standard gas water heaters expire, replace with tankless gas, condensing gas, or solar water heater • When existing electric water heater expires, replace with heat pump or solar water heater	• 48% savings potential in office electronics • 17% savings potential in commercial refrigerators	• 1.5 € price premium per item for high efficiency charging devices and reduction in standby loss • 19 € premium for every 0.65 m^2 of high-efficiency refrigeration area

Waste

Lever	Description	Key volume assumptions	Key cost assumptions
Flaring of landfill gas	• Burn captured landfill gas to prevent methane from entering the atmosphere	• Flaring is assumed to cover the landfills remaining after the implementation of all other cheaper landfill gas reduction lever • Capture rates over the lifetime of the landfill is assumed to be 75%	• Capex: € 50 to 71 per tCO_2e of abatement capacity • Opex: range from € 0.3 to 11 per tCO_2e
Electricity generation from landfill gas	• Capture landfill gas to generate electricity	• LFG electricity generation is limited to a technical potential of 80% of all sites • Capture rates over the lifetime of the landfill is assumed to be 75%	• Capex: € 281 to 402 per tCO_2e of abatement capacity • Opex: range from € 1 to 26 per tCO_2e • Revenues from energy sales: range from € 42 to 55 per tCO_2e
Direct gas use of landfill gas	• Capture landfill gas and sell to a captive player	• LFG direct use is limited to a technical potential of 30% of all sites • Capture rates over the lifetime of the landfill is assumed to be 75%	• Capex: € 84 to 120 per tCO_2e of abatement capacity • Opex: range from € 0.2 to 10 per tCO_2e • Revenues from energy sales: range from € 37 to 51 per tCO_2e
Composting	• Produce compost through biological process where organic waste biodegrades	• Food: 1.0 tCO_2e per ton • Yard trimming: 1.3 CO2e per ton • Paper: 1.9 CO_2e per ton • Wood: 1.5 CO_2e per ton • Textiles: 1.2 CO_2e per ton	• Capex for composting per tonne of organic waste processed: € 34 to 49 per tCO_2e • Opex for composting per tonne of organic waste : € 13 per tCO_2e • Revenue from composting per tonne of organic waste : € 16 per tCO_2e
Recycling	• Recycle raw materials (e.g., metals, paper) for use as inputs in new production	• Paper: 2.9 tCO_2e per ton • Cardboard: 3.7 tCO_2e per ton • Plastic: 1.8 tCO_2e per ton • Glass: 0.4 tCO_2e per ton • Steel: 1.8 tCO_2e per ton • Aluminium: 13.6 tCO_2e per ton	• Capex for Recycling per tonne of waste processed: € 9 to 13 per tCO_2e • Opex for recycling per tonne of waste : € 5 per tCO_2e • Revenues from recycling : – Paper: € 33 per tCO_2e – Cardboard: € 67 per tCO_2e – Plastic: € 67 per tCO_2e – Glass: € 7 per tCO_2e – Steel: € 13 per tCO_2e – Aluminium: € 133 per tCO_2e

Forestry

Lever	Description	Key volume assumptions	Key cost assumptions
Avoided deforestation from slash and burn agriculture	• Reduction of emissions due to deforestation from slash and burn and other from of subsistence agriculture through compensation payments and income support to the rural poor and forest people	• Allocation of total deforestation emissions to Slash and Burn is 44% in Asia, 53% in Africa, 31% in Latin America • Emissions per ha are 70% of biomass and dead wood pools and 15% of soil carbon	• Households deforest 2 ha per yr in Latin America and Asia, 1.5 ha per yr in Africa • Payment to household $ 1,200 per yr for Brazil (WHRC study) – payments in other regions scaled on annual income of bottom 20% of population
Avoided deforestation from cattle ranching	• Reduction of emissions due deforestation from conversion to pastureland and cattle ranching through compensation of landholders for the lost revenue from one-time timber extraction and future cashflow from ranching	• Allocation of total deforestation emissions to Cattle Ranching is: 6% in Asia, 1% in Africa, 65% in Latin America • Emissions per ha are 100% of biomass and dead wood pools and 15% of soil carbon	• Ranching profits are $ 15 per ha yr in Brazil, other regions assumed at constant margin • Timber extraction is 70% of standing merchantable volume
Avoided deforestation from intensive agriculture	• Reduction of emissions due to deforestation from conversion to intensive agriculture through compensation of landholders for the lost revenue from one time timber extraction and future cashflow from agriculture • Reference crops are soybean for South America and palm oil for Asia and Africa	• Allocation of total deforestation emissions to Intensive Agriculture is: 44% in Asia, 35% in Africa, 1% in Latin America • Emissions per ha are 100% of biomass and dead wood pools and 50% of soil carbon	• Intensive agriculture PVs at 4% discount rate are $ 3–5,000 per ha per yr for soy, $15–17,000 per ha for palm oil • Timber extraction is 100% of standing merchantable volume
Avoided deforestation from timber extraction	• Reduction of emissions from deforestation due to unsustainable timber extraction through compensation to landholders for lost timber revenue	• Allocation of total deforestation emissions to timber • Extraction is: 6% in Asia, 10% in Africa, 3% in Latin America • Emissions per ha are 30% of biomass pools, 10% of deadwood and litter pool, and 0% of soil carbon	• Timber extraction removes 15% of standing merchantable volume

Aforestation of marginal croplands and pastureland	• Plantation of forest carbon sinks over marginal pastureland and marginal cropland • Carbon is sequestered in the forest carbon pools • Based on a "carbon graveyard" forest case, where forests are not harvested	• Available area excludes released or fallow croplands allocated to bioenergy • Sequestration rates per ha are based on Moulton and Richards US estimates scaled on regional MAI for long range forestation	• Annual rental for crop and pasture lands is based on regional averages – degraded land is assumed not needing rental • One-time capex and annual management costs are based on US estimates • Payments are matched to carbon flux assuming full repayment of capex and PV of annual expenditure over 50 years of constant sequestration
Reforestation of degraded land	• Plantation of forest carbon sinks over degraded land with no food or feed production value • Carbon is sequestered in the forest carbon pools • Based on a "carbon graveyard" forest case, where forests are not harvested		
Forest management	• Increase of the carbon stock of existing forests based on active or passive management options such as fertilization, fencing to restrict grazing, fire suppression, and improved forest regeneration	• Total opportunity based on Moulton and Richard US estimate and scaled on total forest area • Sequestration rates per ha are based on Moulton and Richards US estimates scaled on regional MAI for long range forestation	• One-time and annual costs based on • US estimates[1]

1 Except that for Canada, where it is based on volume estimates from Chen et al. and IPCC estimates of fertilization costs at $ 20 per tCO_2

Agriculture

	Lever	Description	Key volume assumptions	Key cost assumptions
Cropland management	1. Conservation tillage/residue management	• Reduced tillage of the ground and reduced residue removal/ burning	0.2 to 0.7 tCO_2e/ha/yr	€ -116 to -1/ ha/yr
	2. Improved agronomy practices	• Improved productivity and crop varieties; extended crop rotations and reduced unplanted fallow; less intensive cropping systems; extended use of cover crops	0.4 to 1.0 tCO_2e/ha/yr	€ 8 to 17/ ha/yr
	3. Improved nutrient management	• Adjusting application rates, using slow-release fertilizer forms or nitrification inhibitors, improved timing, placing the nitrogen more precisely	0.3 to 0.6 tCO_2e/ha/yr	€ -146 to -17/ha/yr
	4.1. Improved rice management practices	• Mid-season and shallow flooding drainage to avoid anaerobic conditions	4.0 to 4.9 tCO_2e/ha/yr	€ -5 to 8/ ha/yr
	4.2. Improved rice nutrient management practices	• Use of sulfate fertilizer instead of traditional nitrogen fertilizer	1.2 to 1.5 tCO_2e/ha/yr	€ -122 to 19/ha/yr
Grassland	5. Improved grassland management practices	• Increased grazing intensity, increased productivity (excluding fertilization), irrigating grasslands, fire management and species introduction	0.1 to 0.8 tCO_2e/ha/yr	€ 2 to 4/ ha/yr
	6. Improved grassland nutrient management practices	• More accurate nutrient additions: practices that tailor nutrient additions to plant uptake, such as for croplands • Increased productivity (through better fertilization) For instance, alleviating nutrient deficiencies by fertilizer or organic amendments increases plant litter returns and, hence, soil carbon storage	0.3 to 0.6 tCO_2e/ha/yr	€ -146 to -17/ha/yr

Land restoration	7.	Organic soils restoration	• To be used for agriculture, these soils with high organic content are drained, which favors decomposition and therefore, high CO_2 and N_2O fluxes. The most important mitigation practice is to avoid the drainage of these soils or to re-establish a high water table	33.5 to 70.2 tCO_2e/ha/yr	€ 227/ha/yr
	8.	Degraded land restoration	• Land degraded by excessive disturbance, erosion, organic matter loss, Stalinization, acidification, etc. Abatement practices include re-vegetation (e.g., planting grasses); improving fertility by nutrient *amendments; applying organic* substrates such as manures, biosolids, and composts; reducing tillage and retaining crop residues; and conserving water	3.4 to 4.4 tCO_2e/ha/yr	€ 33/ha/yr
Livestock management	9.	Increased use of livestock feed supplements	• Livestock are important sources of methane, accounting for about one-third of emissions mostly through enteric fermentation	8% to 15%	€ 14 to 79 per tCO_2e
	10.	Use of livestock enteric fermentation vaccines	• The key lever is the potential use of wide range of specific agents or dietary additives, mostly aimed at suppressing methanogenesis. The ones modeled are • Propionate precursors which reduce methane formation by acting as alternative hydrogen acceptors. But as response is elicited only at high doses, propionate precursors are, therefore, quite expensive – Vaccines against methanogenic bacteria which are being developed although not yet available commercially	10% to 15%	€ -128 to 65 per tCO_2e

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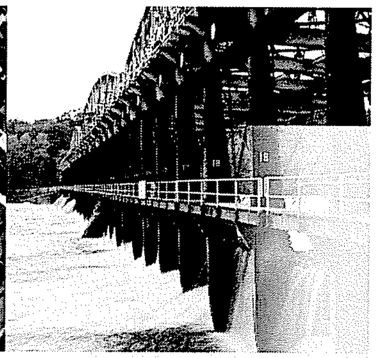

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