James S. Angell (WY Bar No. 6-4086)
Robin Cooley (admitted *pro hac vice*)
Andrea L. Zaccardi (admitted *pro hac vice*)
Earthjustice
1400 Glenarm Place, Suite 300
Denver, CO 80202
Tel: (303) 623-9466
Fax: (303) 623-8083

Attorneys for Protestants

BEFORE THE ENVIRONMENTAL QUALITY COUNCIL
OF THE STATE OF WYOMING

IN THE MATTER OF:	)	
BASIN ELECTRIC POWER COOPERATIVE	)	Docket No. 07-2801
DRY FORK STATION,	)	Presiding Officer, F. David Searle
AIR PERMIT CT–4631	)	
______________________________	)	

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EXHIBIT 1

Intergovernmental Panel on Climate Change
Fourth Assessment Report

Climate Change 2007: Synthesis Report

Summary for Policymakers

NOTE: Un-edited copy prepared for COP-13. The entire report is subject to final copy-edit prior to its final publication.

Based on a draft prepared by:
Lenny Bernstein, Peter Bosch, Osvaldo Canziani, Zhenlin Chen, Renate Christ, Ogunlade Davidson, William Hare, Saleemul Huq, David Karoly, Vladimir Kattsov, Zbigniew Kundzewicz, Jian Liu, Ulrike Lohmann, Martin Manning, Taroh Matsuno, Bettina Menne, Bert Metz, Monirul Mirza, Neville Nicholls, Leonard Nurse, Rajendra Pachauri, Jean Palutikof, Martin Parry, Dahe Qin, Nijavalli Ravindranath, Andy Reisinger, Jiawen Ren, Keywan Riahi, Cynthia Rosenzweig, Matilde Rusticucci, Stephen Schneider, Youba Sokona, Susan Solomon, Peter Stott, Ronald Stouffer, Taishi Sugiyama, Rob Swart, Dennis Tirpak, Coleen Vogel, Gary Yohe

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References in curly brackets { } in this Summary for Policymakers refer to sections, tables and figures in the longer report of this Synthesis Report.

Introduction

This Synthesis Report is based on the assessment carried out by the three Working Groups of the IPCC. It provides an integrated view of climate change as the final part of the IPCC's Fourth Assessment Report.

A complete elaboration of the Topics covered in this summary can be found in this Synthesis Report and in the underlying reports of the three Working Groups.

1. Observed changes in climate and their effects

Warming of the climate system is unequivocal, as is now evident from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice, and rising global average sea level (Figure SPM.1). {1.1}

Eleven of the last twelve years (1995-2006) rank among the twelve warmest years in the instrumental record of global surface temperature (since 1850). The 100-year linear trend (1906-2005) of 0.74 [0.56 to 0.92]°C [1] is larger than the corresponding trend of 0.6 [0.4 to 0.8]°C (1901-2000) given in the Third Assessment Report (TAR) (Figure SPM.1). The temperature increase is widespread over the globe, and is greater at higher northern latitudes. Land regions have warmed faster than the oceans (Figures SPM.2, SPM.4). {1.1, 1.2}

Rising sea level is consistent with warming (Figure SPM.1). Global average sea level has risen since 1961 at an average rate of 1.8 [1.3 to 2.3]mm/yr and since 1993 at 3.1 [2.4 to 3.8]mm/yr, with contributions from thermal expansion, melting glaciers and ice caps, and the polar ice sheets. Whether the faster rate for 1993 to 2003 reflects decadal variation or an increase in the longer-term trend is unclear. {1.1}

Observed decreases in snow and ice extent are also consistent with warming (Figure SPM.1). Satellite data since 1978 show that annual average Arctic sea ice extent has shrunk by 2.7 [2.1 to 3.3]% per decade, with larger decreases in summer of 7.4 [5.0 to 9.8]% per decade. Mountain glaciers and snow cover on average have declined in both hemispheres. {1.1}

From 1900 to 2005, precipitation increased significantly in eastern parts of North and South America, northern Europe and northern and central Asia but declined in the Sahel, the Mediterranean, southern Africa and parts of southern Asia. Globally, the area affected by drought has *likely*[2] increased since the 1970s. {1.1}

It is *very likely* that over the past 50 years: cold days, cold nights and frosts have become less frequent over most land areas, and hot days and hot nights have become more frequent. It is *likely* that: heat waves have become more frequent over most land areas, the frequency of heavy precipitation events has increased over most areas, and since 1975 the incidence of extreme high sea level[3] has increased worldwide. {1.1}

There is observational evidence of an increase in intense tropical cyclone activity in the North Atlantic since about 1970, with limited evidence of increases elsewhere. There is no clear trend in the annual numbers of tropical cyclones. It is difficult to ascertain longer-term trends in cyclone activity, particularly prior to 1970. {1.1}

Average Northern Hemisphere temperatures during the second half of the 20th century were *very likely* higher than during any other 50-year period in the last 500 years and *likely* the highest in at least the past 1300 years. {1.1}

---

[1] Numbers in square brackets indicate a 90% uncertainty interval around a best estimate, i.e. there is an estimated 5% likelihood that the value could be above the range given in square brackets and 5% likelihood that the value could be below that range. Uncertainty intervals are not necessarily symmetric around the corresponding best estimate.

[2] Words in italics represent calibrated expressions of uncertainty and confidence. Relevant terms are explained in the Box 'Treatment of uncertainty' in the Introduction of this Synthesis Report.

[3] Excluding tsunamis, which are not due to climate change. Extreme high sea level depends on average sea level and on regional weather systems. It is defined here as the highest 1% of hourly values of observed sea level at a station for a given reference period.

Changes in temperature, sea level and Northern Hemisphere snow cover

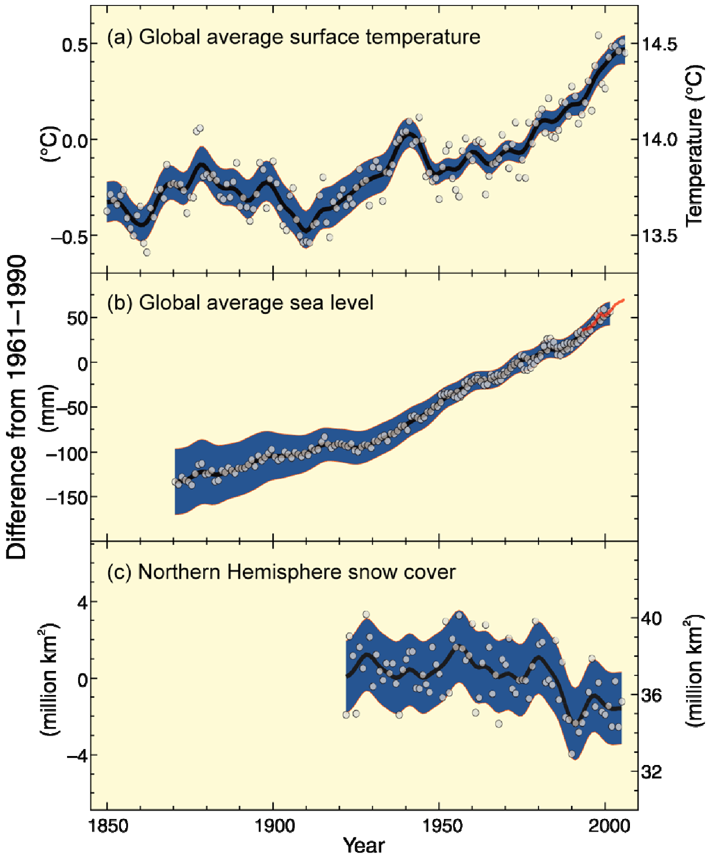

Figure SPM.1. Observed changes in (a) global average surface temperature; (b) global average sea level from tide gauge (blue) and satellite (red) data and (c) Northern Hemisphere snow cover for March-April. All differences are relative to corresponding averages for the period 1961-1990. Smoothed curves represent decadal averaged values while circles show yearly values. The shaded areas are the uncertainty intervals estimated from a comprehensive analysis of known uncertainties (a and b) and from the time series (c). {Figure 1.1}

Observational evidence[4] from all continents and most oceans shows that many natural systems are being affected by regional climate changes, particularly temperature increases. {1.2}

Changes in snow, ice and frozen ground have with *high confidence* increased the number and size of glacial lakes, increased ground instability in mountain and other permafrost regions, and led to changes in some Arctic and Antarctic ecosystems. {1.2}

There is *high confidence* that some hydrological systems have also been affected through increased runoff and earlier spring peak discharge in many glacier- and snow-fed rivers, and effects on thermal structure and water quality of warming rivers and lakes. {1.2}

In terrestrial ecosystems, earlier timing of spring events and poleward and upward shifts in plant and animal ranges are with *very high confidence* linked to recent warming. In some marine and freshwater systems, shifts in ranges and changes in algal, plankton and fish abundance are with *high confidence* associated with rising water temperatures, as well as related changes in ice cover, salinity, oxygen levels and circulation. {1.2}

[4] Based largely on data sets that cover the period since 1970.

Of the more than 29,000 observational data series, from 75 studies, that show significant change in many physical and biological systems, more than 89% are consistent with the direction of change expected as a response to warming (Figure SPM.2). However, there is a notable lack of geographic balance in data and literature on observed changes, with marked scarcity in developing countries. {1.2, 1.3}

Changes in physical and biological systems and surface temperature 1970-2004

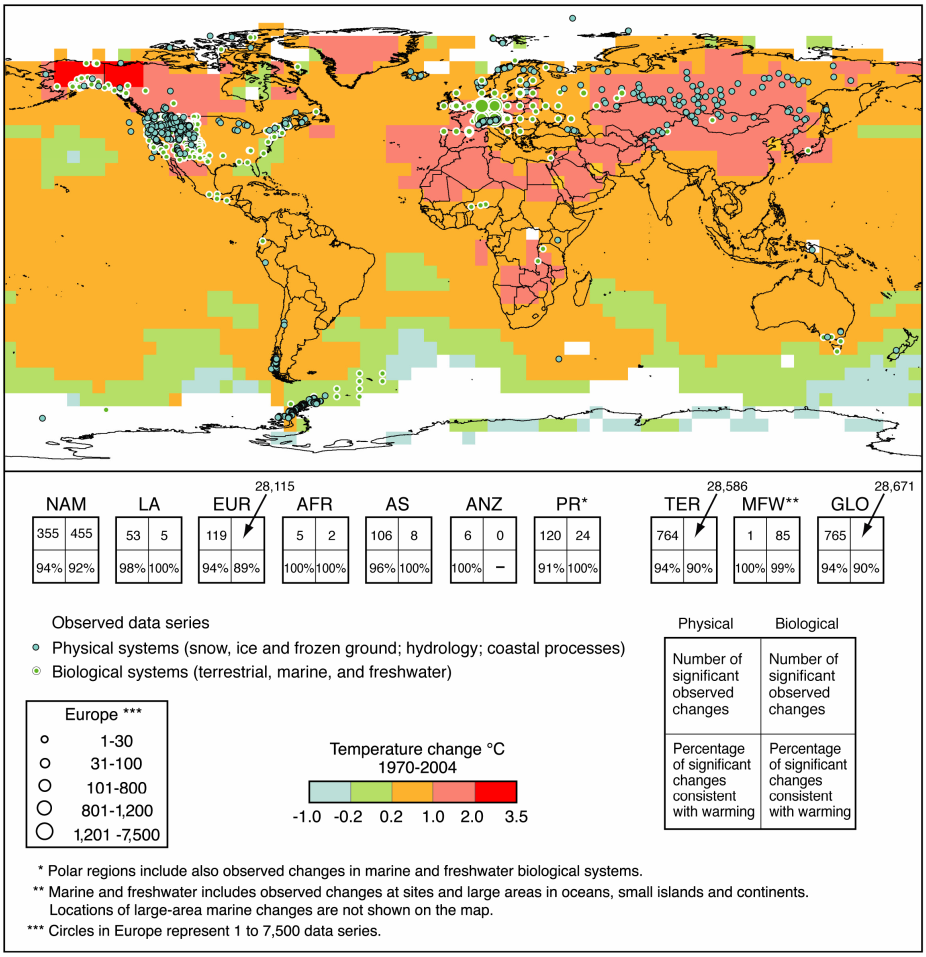

Figure SPM.2. Locations of significant changes in data series of physical systems (snow, ice and frozen ground; hydrology; and coastal processes) and biological systems (terrestrial, marine, and freshwater biological systems), are shown together with surface air temperature changes over the period 1970-2004. A subset of about 29,000 data series was selected from about 80,000 data series from 577 studies. These met the following criteria: (1) ending in 1990 or later; (2) spanning a period of at least 20 years; and (3) showing a significant change in either direction, as assessed in individual studies. These data series are from about 75 studies (of which about 70 are new since the Third Assessment) and contain about 29,000 data series, of which about 28,000 are from European studies. White areas do not contain sufficient observational climate data to estimate a temperature trend. The 2 x 2 boxes show the total number of data series with significant changes (top row) and the percentage of those consistent with warming (bottom row) for (i) continental regions: North America (NAM), Latin America (LA), Europe (EUR), Africa (AFR), Asia (AS), Australia and New Zealand (ANZ), and Polar Regions (PR) and (ii) global-scale: Terrestrial (TER), Marine and Freshwater (MFW), and Global (GLO). The numbers of studies from the seven regional boxes (NAM, EUR, AFR, AS, ANZ, PR) do not add up to the global (GLO) totals because numbers from regions except Polar do not include the numbers related to Marine and Freshwater (MFW) systems. Locations of large-area marine changes are not shown on the map. {Figure 1.2}

There is *medium confidence* that other effects of regional climate change on natural and human environments are emerging, although many are difficult to discern due to adaptation and non-climatic drivers.

They include effects of temperature increases on: {1.2}

- agricultural and forestry management at Northern Hemisphere higher latitudes, such as earlier spring planting of crops, and alterations in disturbance regimes of forests due to fires and pests

- some aspects of human health, such as heat-related mortality in Europe, changes in infectious disease vectors in some areas, and allergenic pollen in Northern Hemisphere high and mid-latitudes
- some human activities in the Arctic (e.g. hunting and travel over snow and ice) and in lower-elevation alpine areas (such as mountain sports).

2. Causes of change

Changes in atmospheric concentrations of greenhouse gases (GHGs) and aerosols, land-cover and solar radiation alter the energy balance of the climate system.

Global GHG emissions due to human activities have grown since pre-industrial times, with an increase of 70% between 1970 and 2004 (Figure SPM.3).[5] {2.1}

Carbon dioxide (CO_2) is the most important anthropogenic GHG. Its annual emissions grew by about 80% between 1970 and 2004. The long-term trend of declining CO_2 emissions per unit of energy supplied reversed after 2000. {2.1}

Global anthropogenic GHG emissions

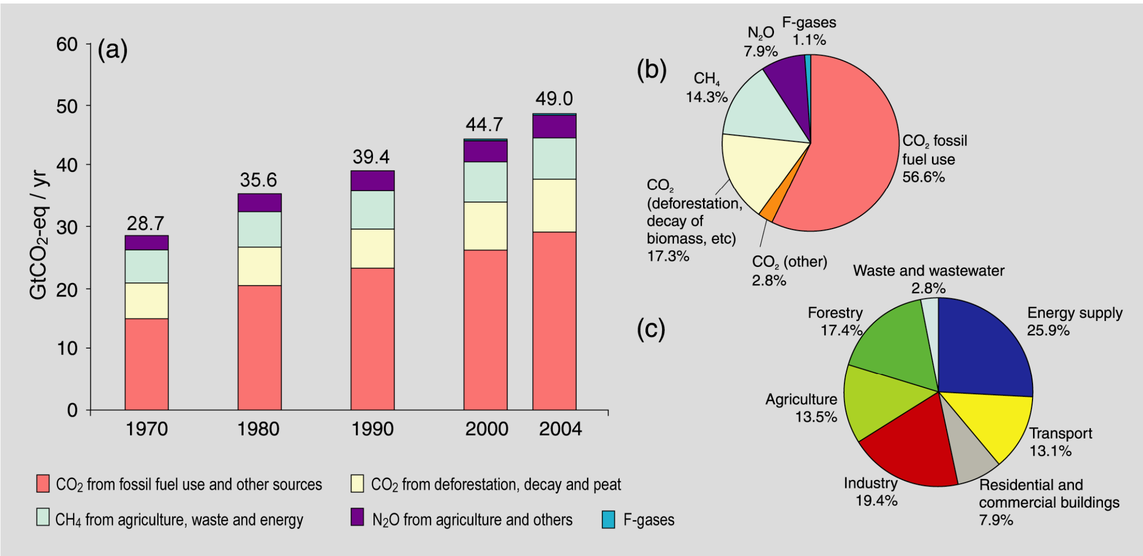

Figure SPM.3. (a) Global annual emissions of anthropogenic GHGs from 1970 to 2004.[5] (b) Share of different anthropogenic GHGs in total emissions in 2004 in terms of CO_2-eq. (c) Share of different sectors in total anthropogenic GHG emissions in 2004 in terms of CO_2-eq. (Forestry includes deforestation). {Figure 2.1}

Global atmospheric concentrations of CO_2, methane (CH_4) and nitrous oxide (N_2O) have increased markedly as a result of human activities since 1750 and now far exceed pre-industrial values determined from ice cores spanning many thousands of years. {2.2}

Atmospheric concentrations of CO_2 (379ppm) and CH_4 (1774 ppb) in 2005 exceed by far the natural range over the last 650,000 years. Global increases in CO_2 concentrations are due primarily to fossil fuel use, with land-use change providing another significant but smaller contribution. It is *very likely* that the observed increase in CH_4 concentration is predominantly due to agriculture and fossil fuel use. Methane growth rates have declined since the early 1990s, consistent with total emissions (sum of anthropogenic and natural sources) being nearly constant during this period. The increase in N_2O concentration is primarily due to agriculture. {2.2}

There is *very high confidence* that the net effect of human activities since 1750 has been one of warming.[6] {2.2}

---

[5] Includes only CO_2, CH_4, N_2O, HFCs, PFCs and SF_6 whose emissions are covered by the UNFCCC. These GHGs are weighted by their 100-year Global Warming Potentials, using values consistent with reporting under the UNFCCC.

[6] Increases in GHGs tend to warm the surface while the net effect of increases in aerosols tends to cool it. The net effect due to human activities since the pre-industrial era is one of warming (+1.6 [+0.6 to +2.4]W/m^2). In comparison, changes in solar irradiance are estimated to have caused a small warming effect (+0.12 [+0.06 to +0.30]W/m^2).

Most of the observed increase in globally-averaged temperatures since the mid-20th century is *very likely* due to the observed increase in anthropogenic GHG concentrations.[7] It is *likely* there has been significant anthropogenic warming over the past 50 years averaged over each continent (except Antarctica) (Figure SPM.4). {2.4}

During the past 50 years, the sum of solar and volcanic forcings would *likely* have produced cooling. Observed patterns of warming and their changes are simulated only by models that include anthropogenic forcings. Difficulties remain in simulating and attributing observed temperature changes at smaller than continental scales. {2.4}

Global and continental temperature change

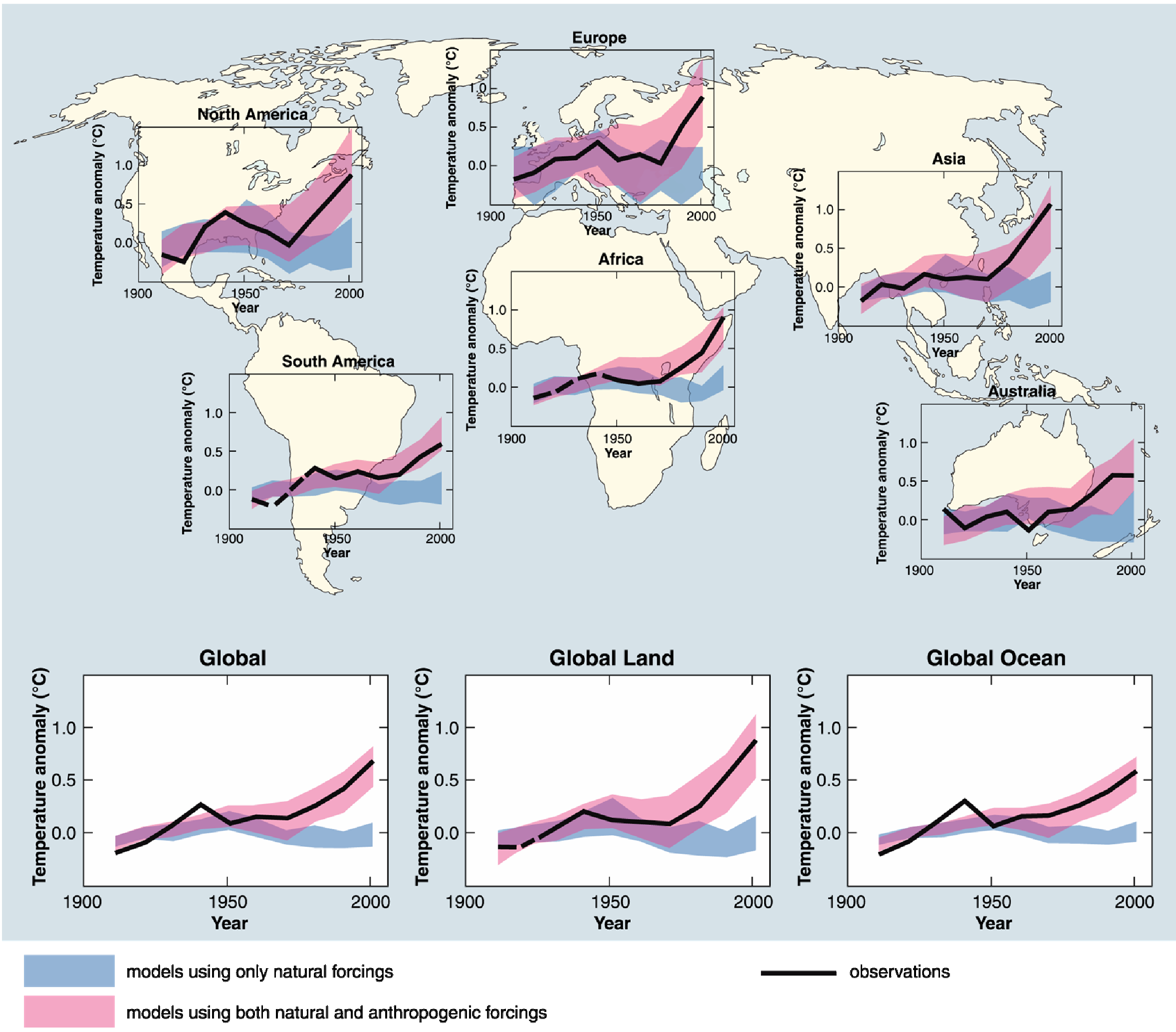

Figure SPM.4. Comparison of observed continental- and global-scale changes in surface temperature with results simulated by climate models using either natural or both natural and anthropogenic forcings. Decadal averages of observations are shown for the period 1906-2005 (black line) plotted against the centre of the decade and relative to the corresponding average for the period 1901-1950. Lines are dashed where spatial coverage is less than 50%. Blue shaded bands show the 5-95% range for 19 simulations from 5 climate models using only the natural forcings due to solar activity and volcanoes. Red shaded bands show the 5-95% range for 58 simulations from 14 climate models using both natural and anthropogenic forcings. {Figure 2.5}

[7] Consideration of remaining uncertainty is based on current methodologies.

Advances since the TAR show that discernible human influences extend beyond average temperature to other aspects of climate. {2.4}

Human influences have: {2.4}

- *very likely* contributed to sea level rise during the latter half of the 20th century
- *likely* contributed to changes in wind patterns, affecting extra-tropical storm tracks and temperature patterns
- *likely* increased temperatures of extreme hot nights, cold nights and cold days
- *more likely than not* increased risk of heat waves, area affected by drought since the 1970s and frequency of heavy precipitation events.

Anthropogenic warming over the last three decades has *likely* had a discernible influence at the global scale on observed changes in many physical and biological systems. {2.4}

Spatial agreement between regions of significant warming across the globe and locations of significant observed changes in many systems consistent with warming is *very unlikely* to be due solely to natural variability. Several modelling studies have linked some specific responses in physical and biological systems to anthropogenic warming. {2.4}

More complete attribution of observed natural system responses to anthropogenic warming is currently prevented by the short time scales of many impact studies, greater natural climate variability at regional scales, contributions of non-climate factors and limited spatial coverage of studies. {2.4}

3. Projected climate change and its impacts

There is *high agreement* and *much evidence* that with current climate change mitigation policies and related sustainable development practices, global GHG emissions will continue to grow over the next few decades. {3.1}

The IPCC Special Report on Emission Scenarios (SRES, 2000) projects an increase of global GHG emissions by 25-90% (CO_2-eq) between 2000 and 2030 (Figure SPM.5), with fossil fuels maintaining their dominant position in the global energy mix to 2030 and beyond. More recent scenarios without additional emissions mitigation are comparable in range. [8, 9] {3.1}

Continued GHG emissions at or above current rates would cause further warming and induce many changes in the global climate system during the 21st century that would *very likely* be larger than those observed during the 20th century (Table SPM.1, Figure SPM.5). {3.2.1}

For the next two decades a warming of about 0.2°C per decade is projected for a range of SRES emission scenarios. Even if the concentrations of all GHGs and aerosols had been kept constant at year 2000 levels, a further warming of about 0.1°C per decade would be expected. Afterwards, temperature projections increasingly depend on specific emission scenarios. {3.2}

[8] For an explanation of SRES emission scenarios, see Box 'SRES scenarios' in Topic 3 of this Synthesis Report. These scenarios do not include additional climate policy above current ones; more recent studies differ with respect to UNFCCC and Kyoto Protocol inclusion.

[9] Emission pathways of mitigation scenarios are discussed in Section 5.

Scenarios for GHG emissions from 2000 to 2100 (in the absence of additional climate policies) and projections of surface temperatures

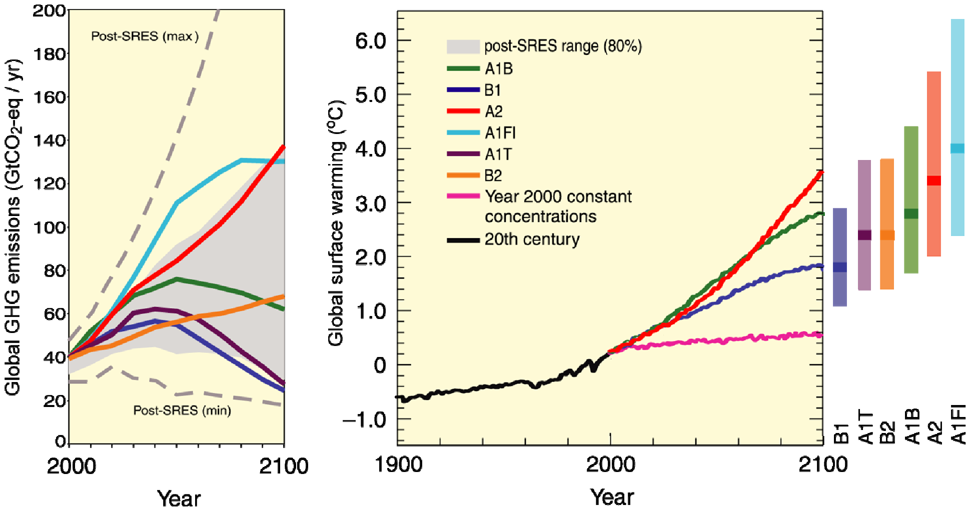

Figure SPM.5. Left Panel: Global GHG emissions (in CO_2-eq) in the absence of climate policies: six illustrative SRES marker scenarios (coloured lines) and the 80th percentile range of recent scenarios published since SRES (post-SRES) (gray shaded area). Dashed lines show the full range of post-SRES scenarios. The emissions cover CO_2, CH_4, N_2O, and F-gases. Right Panel: Solid lines are multi-model global averages of surface warming for scenarios A2, A1B and B1, shown as continuations of the 20th-century simulations. These projections also take into account emissions of short-lived GHGs and aerosols. The pink line is not a scenario, but is for Atmosphere-Ocean General Circulation Model (AOGCM) simulations where atmospheric concentrations are held constant at year 2000 values. The bars at the right of the figure indicate the best estimate (solid line within each bar) and the *likely* range assessed for the six SRES marker scenarios at 2090-2099. All temperatures are relative to the period 1980-1999. {Figures 3.1 and 3.2}

Table SPM.1. Projected global averaged surface warming and sea level rise at the end of the 21st century. {Table 3.1}

	Temperature change (°C at 2090-2099 relative to 1980-1999) [a, d]		Sea level rise (m at 2090-2099 relative to 1980-1999)
Case	Best estimate	*Likely* range	Model-based range excluding future rapid dynamical changes in ice flow
Constant year 2000 concentrations [b]	0.6	0.3 – 0.9	Not available
B1 scenario	1.8	1.1 – 2.9	0.18 – 0.38
A1T scenario	2.4	1.4 – 3.8	0.20 – 0.45
B2 scenario	2.4	1.4 – 3.8	0.20 – 0.43
A1B scenario	2.8	1.7 – 4.4	0.21 – 0.48
A2 scenario	3.4	2.0 – 5.4	0.23 – 0.51
A1FI scenario	4.0	2.4 – 6.4	0.26 – 0.59

Notes:
a) Temperatures are assessed best estimates and likely uncertainty ranges from a hierarchy of models of varying complexity as well as observational constraints.
b) Year 2000 constant composition is derived from Atmosphere-Ocean General Circulation Models (AOGCMs) only.
c) All scenarios above are six SRES marker scenarios. Approximate CO_2-eq concentrations corresponding to the computed radiative forcing due to anthropogenic GHGs and aerosols in 2100 (see p. 823 of the WGI TAR) for the SRES B1, AIT, B2, A1B, A2 and A1FI illustrative marker scenarios are about 600, 700, 800, 850, 1250 and 1550 ppm, respectively.
d) Temperature changes are expressed as the difference from the period 1980-1999. To express the change relative to the period 1850-1899 add 0.5 °C.

The range of projections (Table SPM.1) is broadly consistent with the TAR, but uncertainties and upper ranges for temperature are larger mainly because the broader range of available models suggests stronger climate-carbon cycle feedbacks. Warming reduces terrestrial and ocean uptake of atmospheric CO_2, increasing the fraction of anthropogenic emissions remaining in the atmosphere. The strength of this feedback effect varies markedly among models. {2.3, 3.2.1}

Because understanding of some important effects driving sea level rise is too limited, this report does not assess the likelihood, nor provide a best estimate or an upper bound for sea level rise. Table SPM.1 shows model-based projections of global average sea level rise for 2090-2099.[10] The projections do not include uncertainties in climate-carbon cycle feedbacks nor the full effects of changes in ice sheet flow, therefore the upper values of the ranges are not to be considered upper bounds for sea level rise. They include a contribution from increased Greenland and Antarctic ice flow at the rates observed for 1993-2003, but this could increase or decrease in the future.[11] {3.2.1}

There is now higher confidence than in the TAR in projected patterns of warming and other regional-scale features, including changes in wind patterns, precipitation, and some aspects of extremes and sea ice. {3.2.2}

Regional-scale changes include: {3.2.2}

- warming greatest over land and at most high northern latitudes and least over Southern Ocean and parts of the North Atlantic Ocean, continuing recent observed trends (Figure SPM.6)
- contraction of snow cover area, increases in thaw depth over most permafrost regions, and decrease in sea ice extent; in some projections using SRES scenarios, Arctic late-summer sea ice disappears almost entirely by the latter part of the 21st century
- *very likely* increase in frequency of hot extremes, heat waves, and heavy precipitation
- *likely* increase in tropical cyclone intensity; less confidence in global decrease of tropical cyclone numbers
- poleward shift of extra-tropical storm tracks with consequent changes in wind, precipitation, and temperature patterns
- *very likely* precipitation increases in high latitudes and *likely* decreases in most subtropical land regions, continuing observed recent trends.

There is *high confidence* that by mid-century, annual river runoff and water availability are projected to increase at high latitudes (and in some tropical wet areas) and decrease in some dry regions in the mid-latitudes and tropics. There is also *high confidence* that many semi-arid areas (e.g. Mediterranean basin, western United States, southern Africa and northeast Brazil) will suffer a decrease in water resources due to climate change. {3.3.1; Figure 3.5}

Geographical pattern of surface warming

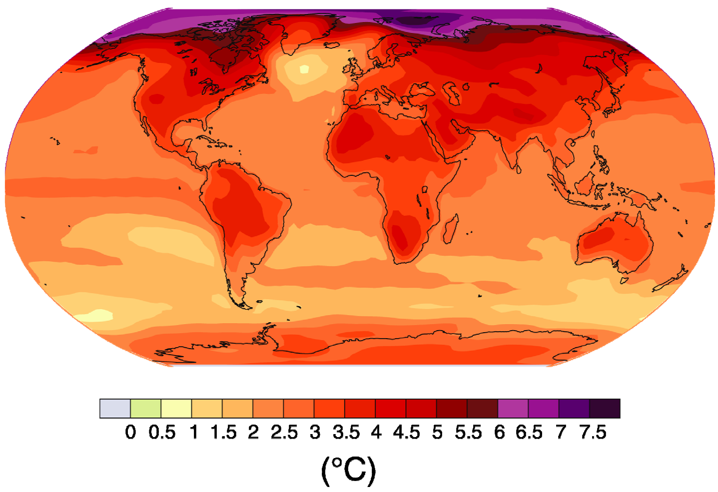

Figure SPM. 6. Projected surface temperature changes for the late 21st century (2090-2099). The map shows the multi-AOGCM average projection for the A1B SRES scenario. All temperatures are relative to the period 1980-1999. {Figure 3.2}

[10] TAR projections were made for 2100, whereas the projections for this report are for 2090-2099. The TAR would have had similar ranges to those in Table SPM.1 if it had treated uncertainties in the same way.

[11] For discussion of the longer term see material below.

Studies since the TAR have enabled more systematic understanding of the timing and magnitude of impacts related to differing amounts and rates of climate change. {3.3.1, 3.3.2}

Figure SPM.7 presents examples of this new information for systems and sectors. The top panel shows impacts increasing with increasing temperature change. Their estimated magnitude and timing is also affected by development pathway (lower panel). {3.3.1}

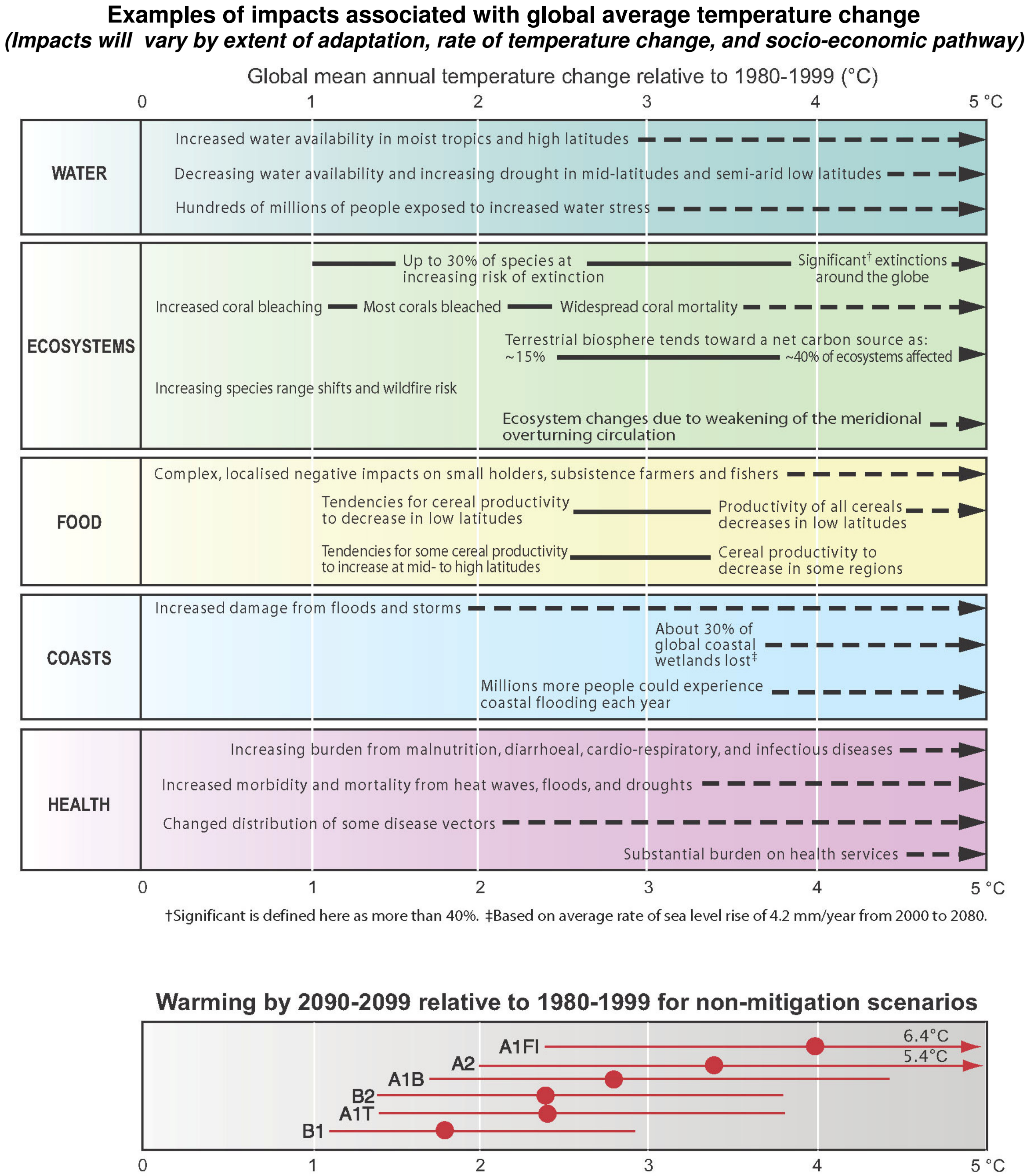

Figure SPM.7. Examples of impacts associated with projected global average surface warming. Upper panel: Illustrative examples of global impacts projected for climate changes (and sea level and atmospheric CO_2 where relevant) associated with different amounts of increase in global average surface temperature in the 21st century. The black lines link impacts; broken-line arrows indicate impacts continuing with increasing temperature. Entries are placed so that the left hand side of text indicates the approximate level of warming that is associated with the onset of a given impact. Quantitative entries for water scarcity and flooding represent the additional impacts of climate change relative to the conditions projected across the range of SRES scenarios A1FI, A2, B1 and B2. Adaptation to climate change is not included in these estimations. Confidence levels for all statements are *high*. Lower panel: Dots and bars indicate the best estimate and *likely* ranges of warming assessed for the six SRES marker scenarios for 2090-2099 relative to 1980-1999. {Figure 3.6}

Examples of some projected impacts for different regions are given in Table SPM.2.

Table SPM.2. Examples of some projected regional impacts. {3.3.2}

Africa	• By 2020, between 75 and 250 million of people are projected to be exposed to increased water stress due to climate change • By 2020, in some countries, yields from rain-fed agriculture could be reduced by up to 50%. Agricultural production, including access to food, in many African countries is projected to be severely compromised. This would further adversely affect food security and exacerbate malnutrition • Towards the end of the 21st century, projected sea-level rise will affect low-lying coastal areas with large populations. The cost of adaptation could amount to at least 5-10% of Gross Domestic Product (GDP) • By 2080, an increase of 5-8% of arid and semi-arid land in Africa is projected under a range of climate scenarios (TS)
Asia	• By the 2050s, freshwater availability in Central, South, East and South-EastAsia, particularly in large river basins, is projected to decrease • Coastal areas, especially heavily-populated megadelta regions in South, East and South-East Asia, will be at greatest risk due to increased flooding from the sea and, in some megadeltas, flooding from the rivers • Climate change is projected to compound the pressures on natural resources and the environment, associated with rapid urbanization, industrialization and economic development • Endemic morbidity and mortality due to diarrhoeal disease primarily associated with floods and droughts are expected to rise in East, South and South-East Asia due to projected changes in the hydrological cycle
Australia and New Zealand	• By 2020, significant loss of biodiversity is projected to occur in some ecologically rich sites including the Great Barrier Reef and Queensland Wet Tropics • By 2030, water security problems are projected to intensify in southern and eastern Australia and, in New Zealand, in Northland and some eastern regions • By 2030, production from agriculture and forestry is projected to decline over much of southern and eastern Australia, and over parts of eastern New Zealand, due to increased drought and fire. However, in New Zealand, initial benefits are projected in some other regions • By 2050, ongoing coastal development and population growth in some areas of Australia and New Zealand are projected to exacerbate risks from sea level rise and increases in the severity and frequency of storms and coastal flooding
Europe	• Climate change is expected to magnify regional differences in Europe's natural resources and assets. Negative impacts will include increased risk of inland flash floods, and more frequent coastal flooding and increased erosion (due to storminess and sea-level rise) • Mountainous areas will face glacier retreat, reduced snow cover and winter tourism, and extensive species losses (in some areas up to 60% under high emissions scenarios by 2080) • In Southern Europe, climate change is projected to worsen conditions (high temperatures and drought) in a region already vulnerable to climate variability, and to reduce water availability, hydropower potential, summer tourism and, in general, crop productivity • Climate change is also projected to increase the health risks due to heat-waves, and the frequency of wildfires
Latin America	• By mid century, increases in temperature and associated decreases in soil water are projected to lead to gradual replacement of tropical forest by savanna in eastern Amazonia. Semi-arid vegetation will tend to be replaced by arid-land vegetation • There is a risk of significant biodiversity loss through species extinction in many areas of tropical Latin America • Productivity of some important crops is projected to decrease and livestock productivity to decline, with adverse consequences for food security. In temperate zones soybean yields are projected to increase. Overall, the number of people at risk of hunger is projected to increase (TS; *medium confidence*) • Changes in precipitation patterns and the disappearance of glaciers are projected to significantly affect water availability for human consumption, agriculture and energy generation
North America	• Warming in western mountains is projected to cause decreased snowpack, more winter flooding, and reduced summer flows, exacerbating competition for over-allocated water resources • In the early decades of the century, moderate climate change is projected to increase aggregate yields of rain-fed agriculture by 5-20%, but with important variability among regions. Major challenges are projected for crops that are near the warm end of their suitable range or which depend on highly utilized water resources • During the course of this century, cities that currently experience heatwaves are expected to be further challenged by an increased number, intensity and duration of heatwaves during the course of the century, with potential for adverse health impacts • Coastal communities and habitats will be increasingly stressed by climate change impacts interacting with development and pollution
Polar Regions	• The main projected biophysical effects are reductions in thickness and extent of glaciers and ice sheets and sea ice, and changes in natural ecosystems with detrimental effects on many organisms including migratory birds, mammals and higher predators • For human communities in the Arctic, impacts, particularly those resulting from changing snow and ice conditions are projected to be mixed • Detrimental impacts would include those on infrastructure and traditional indigenous ways of life • In both polar regions, specific ecosystems and habitats are projected to be vulnerable, as climatic barriers to species invasions are lowered

Table SPM.2. (cont.)

Small Islands	• Sea-level rise is expected to exacerbate inundation, storm surge, erosion and other coastal hazards, thus threatening vital infrastructure, settlements and facilities that support the livelihood of island communities • Deterioration in coastal conditions, for example through erosion of beaches and coral bleaching is expected to affect local resources • By mid-century, climate change is expected to reduce water resources in many small islands, e.g. in the Caribbean and Pacific, to the point where they become insufficient to meet demand during low-rainfall periods • With higher temperatures, increased invasion by non-native species is expected to occur, particularly on mid- and high-latitude islands

Note: Unless stated explicitly, all entries are from WGII SPM text, and are either very high confidence or high confidence statements, reflecting different sectors (Agriculture, Ecosystems, Water, Coasts, Health, Industry and Settlements). The WGII SPM refers to the source of the statements, timelines and temperatures. The magnitude and timing of impacts that will ultimately be realized will vary with the amount and rate of climate change, emission scenarios, development pathways and adaptation.

Some systems, sectors and regions are *likely* to be especially affected by climate change.[12] {3.3.3}

Systems and sectors: {3.3.3}

- particular ecosystems:
  - terrestrial: tundra, boreal forest and mountain regions because of sensitivity to warming; mediterranean-type ecosystems because of reduction in rainfall; and tropical rainforests where precipitation declines
  - coastal: mangroves and salt marshes, due to multiple stresses
  - marine: coral reefs due to multiple stresses; the sea ice biome because of sensitivity to warming
- water resources in some dry regions at mid-latitudes[13] and in the dry tropics, due to changes in rainfall and evapotranspiration, and in areas dependent on snow and ice melt
- agriculture in low-latitudes, due to reduced water availability
- low-lying coastal systems, due to threat of sea level rise and increased risk from extreme weather events
- human health in populations with low adaptive capacity.

Regions: {3.3.3}

- the Arctic, because of the impacts of high rates of projected warming on natural systems and human communities
- Africa, because of low adaptive capacity and projected climate change impacts
- small islands, where there is high exposure of population and infrastructure to projected climate change impacts
- Asian and African megadeltas, due to large populations and high exposure to sea level rise, storm surges and river flooding.

Within other areas, even those with high incomes, some people (such as the poor, young children, and the elderly) can be particularly at risk, and also some areas and some activities. {3.3.3}

Ocean Acidification

The uptake of anthropogenic carbon since 1750 has led to the ocean becoming more acidic with an average decrease in pH of 0.1 units. Increasing atmospheric CO_2 concentrations lead to further acidification. Projections based on SRES scenarios give a reduction in average global surface ocean pH of between 0.14 and 0.35 units over the 21st century. While the effects of observed ocean acidification on the marine biosphere are as yet undocumented, the progressive acidification of oceans is expected to have negative impacts on marine shell-forming organisms (e.g. corals) and their dependent species. {3.3.4}

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[12] Identified on the basis of expert judgement of the assessed literature and considering the magnitude, timing and projected rate of climate change, sensitivity and adaptive capacity.

[13] Including arid and semi-arid regions.

Altered frequencies and intensities of extreme weather, together with sea level rise, are expected to have mostly adverse effects on natural and human systems. {3.3.5}

Examples for selected extremes and sectors are shown in Table SPM.3. {Table 3.2}

Table SPM.3. Examples of possible impacts of climate change due to changes in extreme weather and climate events, based on projections to the mid- to late 21st century. These do not take into account any changes or developments in adaptive capacity. The likelihood estimates in column two relate to the phenomena listed in column one. {Table 3.2}

Phenomenon[a] and direction of trend	Likelihood of future trends based on projections for 21st century using SRES scenarios	Examples of major projected impacts by sector			
		Agriculture, forestry and ecosystems	**Water resources**	**Human health**	**Industry, settlement and society**
Over most land areas, warmer and fewer cold days and nights, warmer and more frequent hot days and nights	*Virtually certain*[b]	Increased yields in colder environments; decreased yields in warmer environments; increased insect outbreaks	Effects on water resources relying on snowmelt; effects on some water supplies	Reduced human mortality from decreased cold exposure	Reduced energy demand for heating; increased demand for cooling; declining air quality in cities; reduced disruption to transport due to snow, ice; effects on winter tourism
Warm spells/heat waves. Frequency increases over most land areas	*Very likely*	Reduced yields in warmer regions due to heat stress; increased danger of wildfire	Increased water demand; water quality problems, e.g. algal blooms	Increased risk of heat-related mortality, especially for the elderly, chronically sick, very young and socially isolated	Reduction in quality of life for people in warm areas without appropriate housing; impacts on the elderly, very young and poor
Heavy precipitation events. Frequency increases over most areas	*Very likely*	Damage to crops; soil erosion, inability to cultivate land due to waterlogging of soils	Adverse effects on quality of surface and groundwater; contamination of water supply; water scarcity may be relieved	Increased risk of deaths, injuries and infectious, respiratory and skin diseases	Disruption of settlements, commerce, transport and societies due to flooding; pressures on urban and rural infrastructures; loss of property
Area affected by drought increases	*Likely*	Land degradation; lower yields/crop damage and failure; increased livestock deaths; increased risk of wildfire	More widespread water stress	Increased risk of food and water shortage; increased risk of malnutrition; increased risk of water-and food-borne diseases	Water shortage for settlements, industry and societies; reduced hydropower generation potentials; potential for population migration
Intense tropical cyclone activity increases	*Likely*	Damage to crops; windthrow (uprooting) of trees; damage to coral reefs	Power outages causing disruption of public water supply	Increased risk of deaths, injuries, water- and food-borne diseases; post-traumatic stress disorders	Disruption by flood and high winds; withdrawal of risk coverage in vulnerable areas by private insurers, potential for population migrations, loss of property
Increased incidence of extreme high sea level (excludes tsunamis)[c]	*Likely*[d]	Salinisation of irrigation water, estuaries and freshwater systems	Decreased freshwater availability due to saltwater intrusion	Increased risk of deaths and injuries by drowning in floods; migration-related health effects	Costs of coastal protection versus costs of land-use relocation; potential for movement of populations and infrastructure; also see tropical cyclones above

Notes:

a) See WGI Table 3.7 for further details regarding definitions.
b) Warming of the most extreme days and nights each year.
c) Extreme high sea level depends on average sea level and on regional weather systems. It is defined as the highest 1% of hourly values of observed sea level at a station for a given reference period.
d) In all scenarios, the projected global average sea level at 2100 is higher than in the reference period. The effect of changes in regional weather systems on sea level extremes has not been assessed.

Anthropogenic warming and sea level rise would continue for centuries due to the time scales associated with climate processes and feedbacks, even if GHG concentrations were to be stabilised. {3.2.3}

Estimated long-term (multi-century) warming corresponding to the six AR4 WG III stabilisation categories is shown in Figure SPM.8.

Estimated multi-century warming relative to 1980-1999 for AR4 stabilisation categories

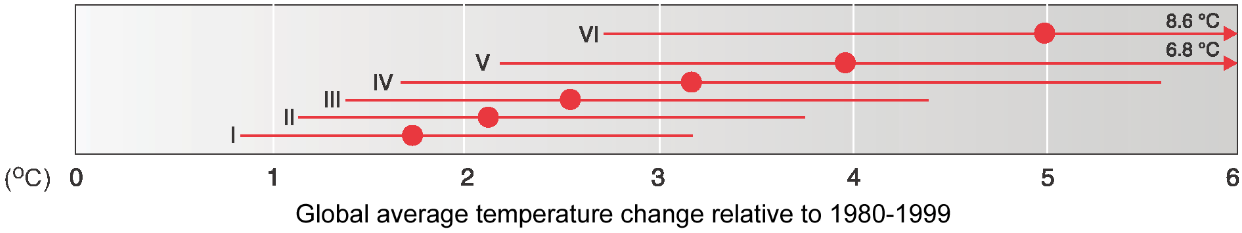

Figure SPM.8. Estimated long-term (multi-century) warming corresponding to the six AR4 WGIII stabilisation categories (Table SPM.6). Temperature scale has been shifted by -0.5°C compared to Table SPM.6 to account approximately for the warming between pre-industrial and 1980-1999. For most stabilisation levels global average temperature is approaching the equilibrium level over a few centuries. For GHG emission scenarios that lead to stabilisation by 2100 at levels comparable to SRES B1 and A1B (600 and 850 ppm CO_2-eq; category IV and V) assessed models project that about 65-70% of the estimated global equilibrium temperature increase assuming a climate sensitivity of 3°C would be realised at the time of stabilisation. For the much lower stabilisation scenarios (category I and II, Figure SPM.11), the equilibrium temperature may be reached earlier. {Figure 3.4}

Contraction of the Greenland ice sheet is projected to continue to contribute to sea level rise after 2100. Current models suggest virtually complete elimination of the Greenland ice sheet and a resulting contribution to sea level rise of about 7 m if global average warming were sustained for millennia in excess of 1.9 to 4.6ºC relative to pre-industrial values. The corresponding future temperatures in Greenland are comparable to those inferred for the last interglacial period 125,000 years ago, when palaeoclimatic information suggests reductions of polar land ice extent and 4 to 6 m of sea level rise. {3.2.3}

Current global model studies project that the Antarctic ice sheet will remain too cold for widespread surface melting and gain mass due to increased snowfall. However, net loss of ice mass could occur if dynamical ice discharge dominates the ice sheet mass balance. {3.2.3}

Anthropogenic warming could lead to some impacts that are abrupt or irreversible, depending upon the rate and magnitude of the climate change. {3.4}

Partial loss of ice sheets on polar land could imply metres of sea level rise, major changes in coastlines and inundation of low-lying areas, with greatest effects in river deltas and low-lying islands. Such changes are projected to occur over millennial time scales, but more rapid sea level rise on century time scales cannot be excluded. {3.4}

Climate change is *likely* to lead to some irreversible impacts. There is *medium confidence* that approximately 20-30% of species assessed so far are *likely* to be at increased risk of extinction if increases in global average warming exceed 1.5-2.5°C (relative to 1980-1999). As global average temperature increase exceeds about 3.5°C, model projections suggest significant extinctions (40-70% of species assessed) around the globe. {3.4}

Based on current model simulations, the meridional overturning circulation (MOC) of the Atlantic Ocean will *very likely* slow down during the 21st century; nevertheless temperatures over the Atlantic and Europe are projected to increase. The MOC is *very unlikely* to undergo a large abrupt transition during the 21st century. Longer-term MOC changes cannot be assessed with confidence. Impacts of large-scale and persistent changes in the MOC are *likely* to include changes in marine ecosystem productivity, fisheries, ocean CO_2 uptake, oceanic oxygen concentrations and terrestrial vegetation. Changes in terrestrial and ocean CO_2 uptake may feed back on the climate system. {3.4}

4. Adaptation and mitigation options[14]

A wide array of adaptation options is available, but more extensive adaptation than is currently occurring is required to reduce vulnerability to climate change. There are barriers, limits and costs, which are not fully understood. {4.2}

Societies have a long record of managing the impacts of weather- and climate-related events. Nevertheless, additional adaptation measures will be required to reduce the adverse impacts of projected climate change and variability, regardless of the scale of mitigation undertaken over the next two to three decades. Moreover, vulnerability to climate change can be exacerbated by other stresses. These arise from, for example, current climate hazards, poverty and unequal access to resources, food insecurity, trends in economic globalisation, conflict and incidence of diseases such as HIV/AIDS. {4.2}

Some planned adaptation to climate change is already occurring on a limited basis. Adaptation can reduce vulnerability especially when it is embedded within broader sectoral initiatives (Table SPM.4). There is *high confidence* that there are viable adaptation options that can be implemented in some sectors at low cost, and/or with high benefit-cost ratios. However, comprehensive estimates of global costs and benefits of adaptation are limited. {4.2, Table 4.1}

Adaptive capacity is intimately connected to social and economic development but is unevenly distributed across and within societies. {4.2}

A range of barriers limit both the implementation and effectiveness of adaptation measures. The capacity to adapt is dynamic and is influenced by a society's productive base including: natural and man-made capital assets, social networks and entitlements, human capital and institutions, governance, national income, health and technology. Even societies with high adaptive capacity remain vulnerable to climate change, variability and extremes. {4.2}

Both bottom-up and top-down studies indicate that there is *high agreement* and *much evidence* of substantial economic potential for the mitigation of global GHG emissions over the coming decades that could offset the projected growth of global emissions or reduce emissions below current levels (Figures SPM.9, SPM.10)[15]. While top-down and bottom-up studies are in line at the global level (Figure SPM.9) there are considerable differences at the sectoral level. {4.3}

No single technology can provide all of the mitigation potential in any sector. The economic mitigation potential, which is generally greater than the market mitigation potential, can only be achieved when adequate policies are in place and barriers removed (Table SPM.5). {4.3}

Bottom-up studies suggest that mitigation opportunities with net negative costs have the potential to reduce emissions by around 6 $GtCO_2$-eq/yr in 2030, realizing which requires dealing with implementation barriers. {4.3}

[14] While this section deals with adaptation and mitigation separately, these responses can be complementary. This theme is discussed in section 5.

[15] The concept of "**mitigation potential**" has been developed to assess the scale of GHG reductions that could be made, relative to emission baselines, for a given level of carbon price (expressed in cost per unit of carbon dioxide equivalent emissions avoided or reduced). Mitigation potential is further differentiated in terms of "market mitigation potential" and "economic mitigation potential".

Market mitigation potential is the mitigation potential based on private costs and private discount rates (reflecting the perspective of private consumers and companies), which might be expected to occur under forecast market conditions, including policies and measures currently in place, noting that barriers limit actual uptake.

Economic mitigation potential is the mitigation potential that takes into account social costs and benefits and social discount rates (reflecting the perspective of society; social discount rates are lower than those used by private investors), assuming that market efficiency is improved by policies and measures and barriers are removed.

Mitigation potential is estimated using different types of approaches. ***Bottom-up studies*** are based on assessment of mitigation options, emphasizing specific technologies and regulations. They are typically sectoral studies taking the macro-economy as unchanged. ***Top-down studies*** assess the economy-wide potential of mitigation options. They use globally consistent frameworks and aggregated information about mitigation options and capture macro-economic and market feedbacks.

Table SPM.4. Selected examples of planned adaptation by sector.

Sector	Adaptation option/strategy	Underlying policy framework	Key constraints and opportunities to implementation (Normal font = constraints; *italics = opportunities*)
Water	Expanded rainwater harvesting; water storage and conservation techniques; water re-use; desalination; water-use and irrigation efficiency	National water policies and integrated water resources management; water-related hazards management	Financial, human resources and physical barriers; *integrated water resources management; synergies with other sectors*
Agriculture	Adjustment of planting dates and crop variety; crop relocation; improved land management, e.g. erosion control and soil protection through tree planting	R&D policies; institutional reform; land tenure and land reform; training; capacity building; crop insurance; financial incentives, e.g. subsidies and tax credits	Technological & financial constraints; access to new varieties; markets; *longer growing season in higher latitudes; revenues from 'new' products*
Infrastructure/settlement (including coastal zones)	Relocation; seawalls and storm surge barriers; dune reinforcement; land acquisition and creation of marshlands/wetlands as buffer against sea level rise and flooding; protection of existing natural barriers	Standards and regulations that integrate climate change considerations into design; land use policies; building codes; insurance	Financial and technological barriers; availability of relocation space; *integrated policies and managements; synergies with sustainable development goals*
Human health	Heat-health action plans; emergency medical services; improved climate-sensitive disease surveillance and control; safe water and improved sanitation	Public health policies that recognise climate risk; strengthened health services; regional and international cooperation	Limits to human tolerance (vulnerable groups); knowledge limitations; financial capacity; *upgraded health services; improved quality of life*
Tourism	Diversification of tourism attractions & revenues; shifting ski slopes to higher altitudes and glaciers; artificial snow-making	Integrated planning (e.g. carrying capacity; linkages with other sectors); financial incentives, e.g. subsidies and tax credits	Appeal/marketing of new attractions; financial and logistical challenges; potential adverse impact on other sectors (e.g. artificial snow-making may increase energy use); *revenues from 'new' attractions; involvement of wider group of stakeholders*
Transport	Realignment/relocation; design standards and planning for roads, rail, and other infrastructure to cope with warming and drainage	Integrating climate change considerations into national transport policy; investment in R&D for special situations, e.g. permafrost areas	Financial & technological barriers; availability of less vulnerable routes; *improved technologies and integration with key sectors (e.g. energy)*
Energy	Strengthening of overhead transmission and distribution infrastructure; underground cabling for utilities; energy efficiency; use of renewable sources; reduced dependence on single sources of energy	National energy policies, regulations, and fiscal and financial incentives to encourage use of alternative sources; incorporating climate change in design standards	Access to viable alternatives; financial and technological barriers; acceptance of new technologies; *stimulation of new technologies; use of local resources*

Note: Other examples from many sectors would include early warning systems.

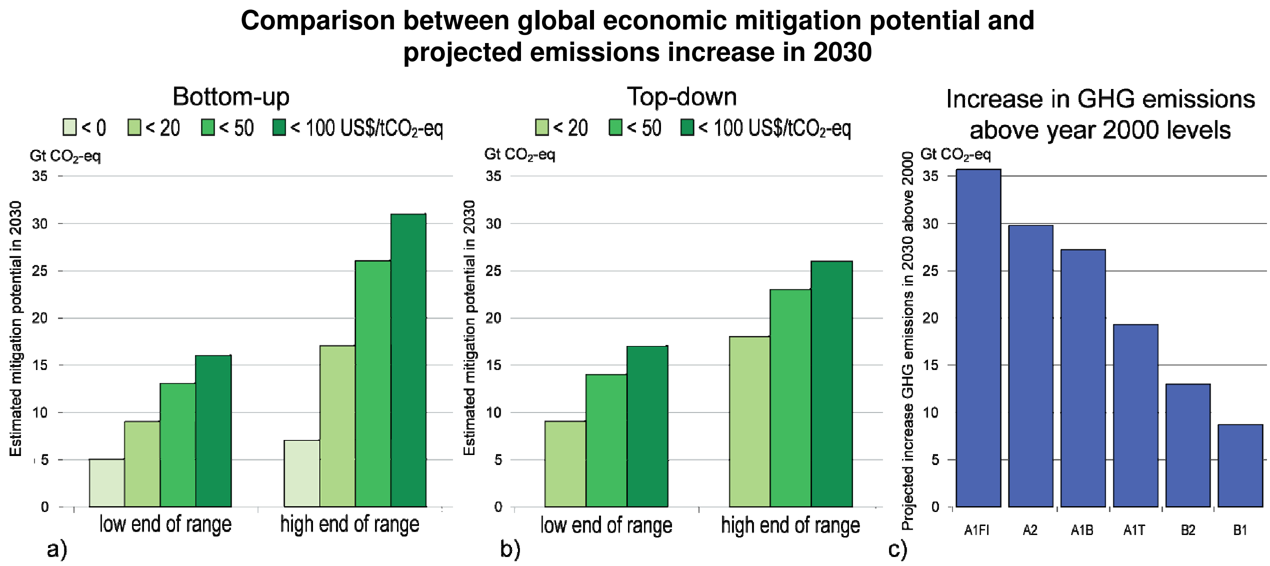

Figure SPM.9. Global economic mitigation potential in 2030 estimated from bottom-up (Panel a) and top-down (Panel b) studies, compared with the projected emission increases from SRES scenarios relative to 2000 GHG emissions of 40.8 $GtCO_2$-eq (Panel c). Note: GHG emissions in 2000 are exclusive of emissions of decay of above ground biomass that remains after logging and deforestation and from peat fires and drained peat soils, to ensure consistency with the SRES emission results. {Figure 4.1}

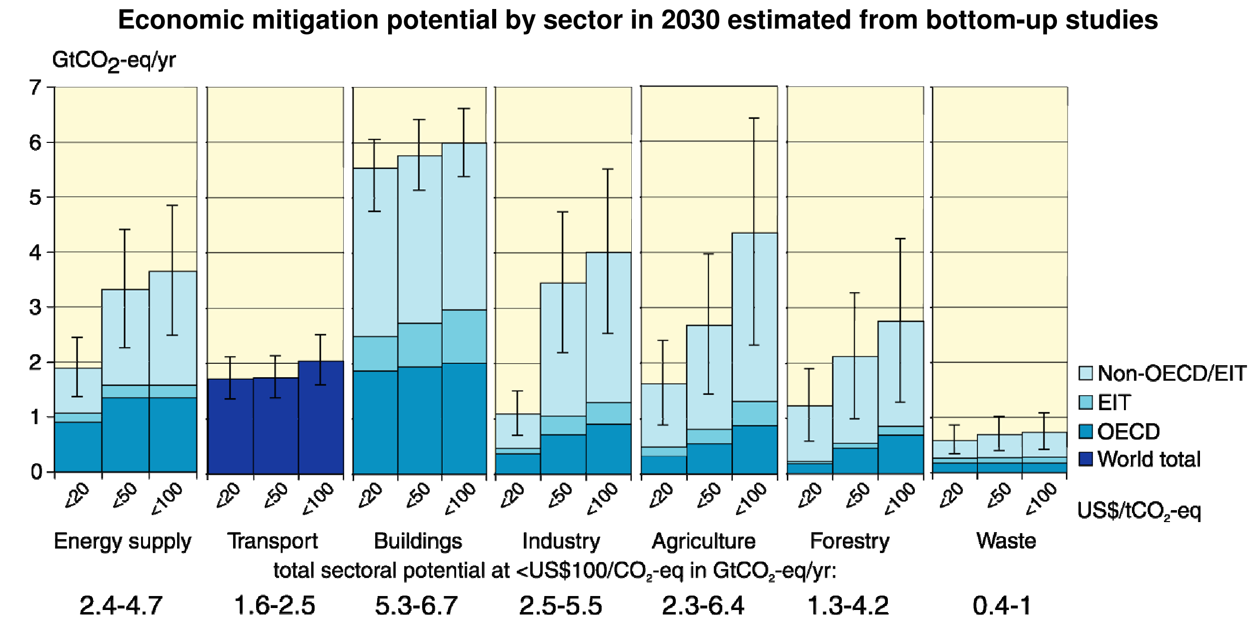

Figure SPM.10. Estimated economic mitigation potential by sector in 2030 from bottom-up studies, compared to the respective baselines assumed in the sector assessments. The potentials do not include non-technical options such as lifestyle changes. {Figure 4.2}

Notes:

a) The ranges for global economic potentials as assessed in each sector are shown by vertical lines. The ranges are based on end-use allocations of emissions, meaning that emissions of electricity use are counted towards the end-use sectors and not to the energy supply sector.

b) The estimated potentials have been constrained by the availability of studies particularly at high carbon price levels.

c) Sectors used different baselines. For industry the SRES B2 baseline was taken, for energy supply and transport the WEO 2004 baseline was used; the building sector is based on a baseline in between SRES B2 and A1B; for waste, SRES A1B driving forces were used to construct a waste specific baseline; agriculture and forestry used baselines that mostly used B2 driving forces.

d) Only global totals for transport are shown because international aviation is included.

e) Categories excluded are: non-CO_2 emissions in buildings and transport, part of material efficiency options, heat production and cogeneration in energy supply, heavy duty vehicles, shipping and high-occupancy passenger transport, most high-cost options for buildings, wastewater treatment, emission reduction from coal mines and gas pipelines, fluorinated gases from energy supply and transport. The underestimation of the total economic potential from these emissions is of the order of 10-15%.

Table SPM.5. Selected examples of key sectoral mitigation technologies, policies and measures, constraints and opportunities. {Table 4.2}

Sector	Key mitigation technologies and practices currently commercially available. *Key mitigation technologies and practices projected to be commercialised before 2030 shown in italics.*	Policies, measures and instruments shown to be environmentally effective	Key constraints or opportunities (Normal font = constraints; *italics = opportunities*)
Energy Supply	Improved supply and distribution efficiency; fuel switching from coal to gas; nuclear power; renewable heat and power (hydropower, solar, wind, geothermal and bioenergy); combined heat and power; early applications of Carbon Dioxide Capture and Storage (CCS) (e.g. storage of removed CO_2 from natural gas); *CCS for gas, biomass and coal-fired electricity generating facilities; advanced nuclear power; advanced renewable energy, including tidal and wave energy, concentrating solar, and solar photovoltaics*	Reduction of fossil fuel subsidies; Taxes or carbon charges on fossil fuels	Resistance by vested interests may make them difficult to implement
		Feed-in tariffs for renewable energy technologies; Renewable energy obligations; Producer subsidies	*May be appropriate to create markets for low emissions technologies*
Transport	More fuel efficient vehicles; hybrid vehicles; cleaner diesel vehicles; biofuels; modal shifts from road transport to rail and public transport systems; non-motorised transport (cycling, walking); land-use and transport planning; *Second generation biofuels; higher efficiency aircraft; advanced electric and hybrid vehicles with more powerful and reliable batteries*	Mandatory fuel economy, biofuel blending and CO_2 standards for road transport	Partial coverage of vehicle fleet may limit effectiveness
		Taxes on vehicle purchase, registration, use and motor fuels, road and parking pricing	Effectiveness may drop with higher incomes
		Influence mobility needs through land use regulations, and infrastructure planning; Investment in attractive public transport facilities and non-motorised forms of transport	*Particularly appropriate for countries that are building up their transportation systems*
Buildings	Efficient lighting and daylighting; more efficient electrical appliances and heating and cooling devices; improved cook stoves, improved insulation; passive and active solar design for heating and cooling; alternative refrigeration fluids, recovery and recycling of fluorinated gases; *Integrated design of commercial buildings including technologies, such as intelligent meters that provide feedback and control; solar photovoltaics integrated in buildings*	Appliance standards and labelling	Periodic revision of standards needed
		Building codes and certification	*Attractive for new buildings.* Enforcement can be difficult
		Demand-side management programmes	Need for regulations so that utilities may profit
		Public sector leadership programmes, including procurement	*Government purchasing can expand demand for energy-efficient products*
		Incentives for energy service companies (ESCOs)	*Success factor: Access to third party financing*
Industry	More efficient end-use electrical equipment; heat and power recovery; material recycling and substitution; control of non-CO_2 gas emissions; and a wide array of process-specific technologies; *Advanced energy efficiency; CCS for cement, ammonia, and iron manufacture; inert electrodes for aluminium manufacture*	Provision of benchmark information; Performance standards; Subsidies, tax credits	*May be appropriate to stimulate technology uptake.* Stability of national policy important in view of international competitiveness
		Tradable permits	Predictable allocation mechanisms and stable price signals important for investments
		Voluntary agreements	Success factors include: clear targets, a baseline scenario, third party involvement in design and review and formal provisions of monitoring, close cooperation between government and industry
Agriculture	Improved crop and grazing land management to increase soil carbon storage; restoration of cultivated peaty soils and degraded lands; improved rice cultivation techniques and livestock and manure management to reduce CH_4 emissions; improved nitrogen fertiliser application techniques to reduce N_2O emissions; dedicated energy crops to replace fossil fuel use; improved energy efficiency; *Improvements of crop yields*	Financial incentives and regulations for improved land management, maintaining soil carbon content, efficient use of fertilisers and irrigation	*May encourage synergy with sustainable development and with reducing vulnerability to climate change, thereby overcoming barriers to implementation*

Table SPM.5. (cont.)

Sector	Key mitigation technologies and practices currently commercially available. *Key mitigation technologies and practices projected to be commercialised before 2030 shown in italics.*	Policies, measures and instruments shown to be environmentally effective	Key constraints or opportunities (Normal font = constraints; *italics = opportunities*)
Forestry/ forests	Afforestation; reforestation; forest management; reduced deforestation; harvested wood product management; use of forestry products for bioenergy to replace fossil fuel use; *Tree species improvement to increase biomass productivity and carbon sequestration. Improved remote sensing technologies for analysis of vegetation/ soil carbon sequestration potential and mapping land use change*	Financial incentives (national and international) to increase forest area, to reduce deforestation, and to maintain and manage forests; land-use regulation and enforcement	Constraints include lack of investment capital and land tenure issues. *Can help poverty alleviation*
Waste	Landfill CH_4 recovery; waste incineration with energy recovery; composting of organic waste; controlled waste water treatment; recycling and waste minimisation; *biocovers and biofilters to optimise CH_4 oxidation*	Financial incentives for improved waste and wastewater management	*May stimulate technology diffusion*
		Renewable energy incentives or obligations	Local availability of low-cost fuel
		Waste management regulations	Most effectively applied at national level with enforcement strategies

Future energy infrastructure investment decisions, expected to exceed 20 trillion US$[16] between 2005 and 2030, will have long-term impacts on GHG emissions, because of the long life-times of energy plants and other infrastructure capital stock. The widespread diffusion of low-carbon technologies may take many decades, even if early investments in these technologies are made attractive. Initial estimates show that returning global energy-related CO_2 emissions to 2005 levels by 2030 would require a large shift in investment patterns, although the net additional investment required ranges from negligible to 5-10%. {4.3}

A wide variety of policies and instruments are available to governments to create the incentives for mitigation action. Their applicability depends on national circumstances and sectoral context (Table SPM.5). {4.3}

They include integrating climate policies in wider development policies, regulations and standards, taxes and charges, tradable permits, financial incentives, voluntary agreements, information instruments, and research, development and demonstration (RD&D). {4.3}

An effective carbon-price signal could realise significant mitigation potential in all sectors. Modelling studies show global carbon prices rising to 20-80 US$/t$CO_2$-eq by 2030 are consistent with stabilisation at around 550 ppm CO_2-eq by 2100. For the same stabilisation level, induced technological change may lower these price ranges to 5-65 US$/t$CO_2$-eq in 2030.[17] {4.3}

There is *high agreement* and *much evidence* that mitigation actions can result in near-term co-benefits (e.g. improved health due to reduced air pollution) that may offset a substantial fraction of mitigation costs. {4.3}

There is *high agreement* and *medium evidence* that Annex I countries' actions may affect the global economy and global emissions, although the scale of carbon leakage remains uncertain.[18] {4.3}

[16] 20 trillion = 20,000 billion = 20×10^{12}

[17] Studies on mitigation portfolios and macro-economic costs assessed in this report are based on top-down modelling. Most models use a global least cost approach to mitigation portfolios, with universal emissions trading, assuming transparent markets, no transaction cost, and thus perfect implementation of mitigation measures throughout the 21st century. Costs are given for a specific point in time. Global modelled costs will increase if some regions, sectors (e.g. land-use), options or gases are excluded. Global modelled costs will decrease with lower baselines, use of revenues from carbon taxes and auctioned permits, and if induced technological learning is included. These models do not consider climate benefits and generally also co-benefits of mitigation measures, or equity issues. Significant progress has been achieved in applying approaches based on induced technological change to stabilisation studies; however, conceptual issues remain. In the models that consider induced technological change, projected costs for a given stabilisation level are reduced; the reductions are greater at lower stabilisation level.

[18] Further details may be found in Topic 4 of this Synthesis Report.

Fossil fuel exporting nations (in both Annex I and non-Annex I countries) may expect, as indicated in the TAR, lower demand and prices and lower GDP growth due to mitigation policies. The extent of this spill over depends strongly on assumptions related to policy decisions and oil market conditions. {4.3}

There is also *high agreement* and *medium evidence* that changes in lifestyle, behaviour patterns and management practices can contribute to climate change mitigation across all sectors. {4.3}

Many options for reducing global GHG emissions through international cooperation exist. There is *high agreement* and *much evidence* that notable achievements of the UNFCCC and its Kyoto Protocol are the establishment of a global response to climate change, stimulation of an array of national policies, and the creation of an international carbon market and new institutional mechanisms that may provide the foundation for future mitigation efforts. Progress has also been made in addressing adaptation within the UNFCCC and additional international initiatives have been suggested. {4.5}

Greater cooperative efforts and expansion of market mechanisms will help to reduce global costs for achieving a given level of mitigation, or will improve environmental effectiveness. Efforts can include diverse elements such as emissions targets; sectoral, local, sub-national and regional actions; RD&D programmes; adopting common policies; implementing development oriented actions; or expanding financing instruments. {4.5}

In several sectors, climate response options can be implemented to realise synergies and avoid conflicts with other dimensions of sustainable development. Decisions about macroeconomic and other non-climate policies can significantly affect emissions, adaptive capacity and vulnerability. {4.4, 5.8}

Making development more sustainable can enhance mitigative and adaptive capacities, reduce emissions, and reduce vulnerability, but there may be barriers to implementation. On the other hand, it is *very likely* that climate change can slow the pace of progress towards sustainable development. Over the next half-century, climate change could impede achievement of the Millennium Development Goals. {5.8}

5. The long-term perspective

Determining what constitutes "dangerous anthropogenic interference with the climate system" in relation to Article 2 of the UNFCCC involves value judgements. Science can support informed decisions on this issue, including by providing criteria for judging which vulnerabilities might be labelled "key". {Box 'Key Vulnerabilities and Article 2 of the UNFCCC', Topic 5}

Key vulnerabilities[19] may be associated with many climate sensitive systems including food supply, infrastructure, health, water resources, coastal systems, ecosystems, global biogeochemical cycles, ice sheets, and modes of oceanic and atmospheric circulation.{Box 'Key Vulnerabilities and Article 2 of the UNFCCC', Topic 5}

The five "reasons for concern" identified in the TAR remain a viable framework to consider key vulnerabilities. These "reasons" are assessed here to be stronger than in the TAR. Many risks are identified with higher confidence. Some risks are projected to be larger or to occur at lower increases in temperature. Understanding about the relationship between impacts (the basis for "reasons for concern" in the TAR) and vulnerability (that includes the ability to adapt to impacts) has improved. {5.2}

This is due to more precise identification of the circumstances that make systems, sectors and regions especially vulnerable, and growing evidence of the risks of very large impacts on multiple century time scales. {5.2}

[19] Key Vulnerabilities can be identified based on a number of criteria in the literature, including magnitude, timing, persistence/reversibility, the potential for adaptation, distributional aspects, likelihood and 'importance' of the impacts.

- **Risks to unique and threatened systems.** There is new and stronger evidence of observed impacts of climate change on unique and vulnerable systems (such as polar and high mountain communities and ecosystems), with increasing levels of adverse impacts as temperatures increase further. An increasing risk of species extinction and coral reef damage is projected with higher confidence than in the TAR as warming proceeds. There is *medium confidence* that approximately 20-30% of plant and animal species assessed so far are *likely* to be at increased risk of extinction if increases in global average temperature exceed 1.5-2.5°C over 1980-1999 levels. Confidence has increased that a 1-2°C increase in global mean temperature above 1990 levels (about 1.5-2.5°C above pre-industrial) poses significant risks to many unique and threatened systems including many biodiversity hotspots. Corals are vulnerable to thermal stress and have low adaptive capacity. Increases in sea surface temperature of about 1-3°C are projected to result in more frequent coral bleaching events and widespread mortality, unless there is thermal adaptation or acclimatization by corals. Increasing vulnerability of indigenous communities in the Arctic and small island communities to warming is projected. {5.2}
- **Risks of extreme weather events.** Responses to some recent extreme events reveal higher levels of vulnerability than the TAR. There is now higher confidence in the projected increases in droughts, heat waves, and floods as well as their adverse impacts. {5.2}
- **Distribution of impacts and vulnerabilities.** There are sharp differences across regions and those in the weakest economic position are often the most vulnerable to climate change. There is increasing evidence of greater vulnerability of specific groups such as the poor and elderly in not only developing but also developed countries. Moreover, there is increased evidence that low-latitude and less-developed areas generally face greater risk, for example in dry areas and megadeltas. {5.2}
- **Aggregate impacts.** Compared to the TAR, initial net market-based benefits from climate change are projected to peak at a lower magnitude of warming, while damages would be higher for larger magnitudes of warming. The net costs of impacts of increased warming are projected to increase over time. {5.2}
- **Risks of large-scale singularities.** There is *high confidence* that global warming over many centuries would lead to a sea level rise contribution from thermal expansion alone which is projected to be much larger than observed over the 20th century, with loss of coastal area and associated impacts. There is better understanding than in the TAR that the risk of additional contributions to sea level rise from both the Greenland and possibly Antarctic ice sheets may be larger than projected by ice sheet models and could occur on century time scales. This is because ice dynamical processes seen in recent observations but not fully included in ice sheet models assessed in AR4 could increase the rate of ice loss. {5.2}

There is *high confidence* that neither adaptation nor mitigation alone can avoid all climate change impacts; however, they can complement each other and together can significantly reduce the risks of climate change. {5.3}

Adaptation is necessary in the short and longer term to address impacts resulting from the warming that would occur even for the lowest stabilisation scenarios assessed. There are barriers, limits and costs, but these are not fully understood. Unmitigated climate change would, in the long term, be *likely* to exceed the capacity of natural, managed and human systems to adapt. The time at which such limits could be reached will vary between sectors and regions. Early mitigation actions would avoid further locking in carbon intensive infrastructure and reduce climate change and associated adaptation needs. {5.2, 5.3}

Many impacts can be reduced, delayed or avoided by mitigation. Mitigation efforts and investments over the next two to three decades will have a large impact on opportunities to achieve lower stabilisation levels. Delayed emission reductions significantly constrain the opportunities to achieve lower stabilisation levels and increase the risk of more severe climate change impacts. {5.3, 5.4, 5.7}

In order to stabilise the concentration of GHGs in the atmosphere, emissions would need to peak and decline thereafter. The lower the stabilisation level, the more quickly this peak and decline would need to occur.[20] {5.4}

[20] For the lowest mitigation scenario category assessed, emissions would need to peak by 2015 and for the highest by 2090 (see Table SPM.6). Scenarios that use alternative emission pathways show substantial differences in the rate of global climate change.

Table SPM.6 and Figure SPM.11 summarise the required emission levels for different groups of stabilisation concentrations and the resulting equilibrium global warming and long-term sea level rise due to thermal expansion only.[21] The timing and level of mitigation to reach a given temperature stabilisation level is earlier and more stringent if climate sensitivity is high than if it is low. {5.4, 5.7}

Sea level rise under warming is inevitable. Thermal expansion would continue for many centuries after GHG concentrations have stabilised, for any of the stabilisation levels assessed, causing an eventual sea level rise much larger than projected for the 21st century. The eventual contributions from Greenland ice sheet loss could be several metres, and larger than from thermal expansion, should warming in excess of 1.9-4.6°C above pre-industrial be sustained over many centuries. The long time scales of thermal expansion and ice sheet response to warming imply that stabilisation of GHG concentrations at or above present levels would not stabilise sea level for many centuries. {5.3, 5.4}

Table SPM.6. Characteristics of post-TAR stabilisation scenarios and resulting long-term equilibrium global average temperature and the sea level rise component from thermal expansion only. {Table 5.1}[a]

Category	CO_2 concentration at stabilisation (2005 = 379 ppm) [(b)]	CO_2-equivalent Concentration at stabilisation including GHGs and aerosols (2005 = 375 ppm) [(b)]	Peaking year for CO_2 emissions [(a, c)]	Change in global CO_2 emissions in 2050 (% of 2000 emissions) [(a, c)]	Global average temperature increase above pre-industrial at equilibrium, using "best estimate" climate sensitivity [(d), (e)]	Global average sea level rise above pre-industrial at equilibrium from thermal expansion only [(f)]	Number of assessed scenarios
	ppm	ppm	year	percent	°C	metres	
I	350 – 400	445 – 490	2000 – 2015	-85 to -50	2.0 – 2.4	0.4 – 1.4	6
II	400 – 440	490 – 535	2000 – 2020	-60 to -30	2.4 – 2.8	0.5 – 1.7	18
III	440 – 485	535 – 590	2010 – 2030	-30 to +5	2.8 – 3.2	0.6 – 1.9	21
IV	485 – 570	590 – 710	2020 – 2060	+10 to +60	3.2 – 4.0	0.6 – 2.4	118
V	570 – 660	710 – 855	2050 – 2080	+25 to +85	4.0 – 4.9	0.8 – 2.9	9
VI	660 – 790	855 – 1130	2060 – 2090	+90 to +140	4.9 – 6.1	1.0 – 3.7	5

Notes:

a) *The emission reductions to meet a particular stabilization level reported in the mitigation studies assessed here might be underestimated due to missing carbon cycle feedbacks (see also Topic 2).*

b) *Atmospheric CO_2 concentrations were 379 ppm in 2005. The best estimate of total CO_2-eq concentration in 2005 for all long-lived GHGs is about 455 ppm, while the corresponding value including the net effect of all anthropogenic forcing agents is 375 ppm CO_2-eq.*

c) *Ranges correspond to the 15th to 85th percentile of the post-TAR scenario distribution. CO_2 emissions are shown so multi-gas scenarios can be compared with CO_2-only scenarios (see Figure SPM.3).*

d) *The best estimate of climate sensitivity is 3°C.*

e) *Note that global average temperature at equilibrium is different from expected global average temperature at the time of stabilization of GHG concentrations due to the inertia of the climate system. For the majority of scenarios assessed, stabilisation of GHG concentrations occurs between 2100 and 2150 (see also Footnote 21).*

f) *Equilibrium sea level rise is for the contribution from ocean thermal expansion only and does not reach equilibrium for at least many centuries. These values have been estimated using relatively simple climate models (one low resolution AOGCM and several EMICs based on the best estimate of 3°C climate sensitivity) and do not include contributions from melting ice sheets, glaciers and ice caps. Long-term thermal expansion is projected to result in 0.2 to 0.6 m per degree Celsius of global average warming above pre-industrial. (AOGCM refers to Atmosphere Ocean General Circulation Models and EMICs to Earth System Models of Intermediate Complexity.)*

[21] Estimates for the evolution of temperature over the course of this century are not available in the AR4 for the stabilisation scenarios. For most stabilisation levels global average temperature is approaching the equilibrium level over a few centuries. For the much lower stabilisation scenarios (category I and II, Figure SPM.11), the equilibrium temperature may be reached earlier.

CO_2 emissions and equilibrium temperature increases for a range of stabilisation levels

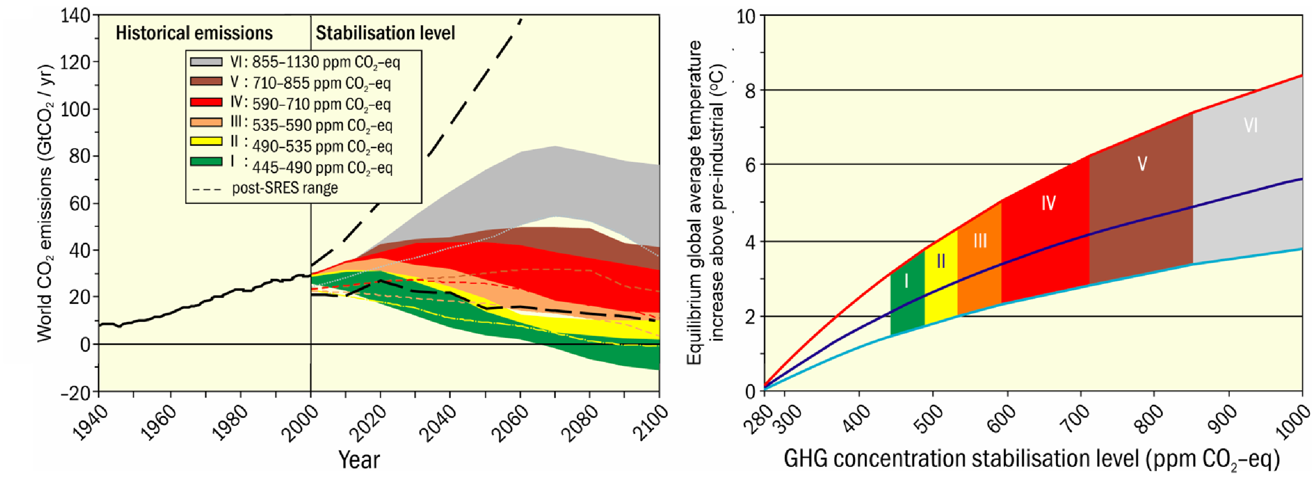

Figure SPM.11. Global CO_2 emissions for 1940 to 2000 and emissions ranges for categories of stabilisation scenarios from 2000 to 2100 (left-hand panel); and the corresponding relationship between the stabilisation target and the *likely* equilibrium global average temperature increase above pre-industrial (right-hand panel). Approaching equilibrium can take several centuries, especially for scenarios with higher levels of stabilisation. Coloured shadings show stabilisation scenarios grouped according to different targets (stabilisation category I to VI). Right-hand panel shows ranges of global average temperature change above pre-industrial, using (i) "best estimate" climate sensitivity of 3℃ (black line in middle of shaded area), (ii) upper bound of *likely* range of climate sensitivity of 4.5℃ (red line at top of shaded area) (iii) lower bound of *likely* range of climate sensitivity of 2℃ (blue line at bottom of shaded area). Black dashed lines in the left panel give the emissions range of recent baseline scenarios published since the SRES (2000). Emissions ranges of the stabilisation scenarios comprise CO_2-only and multigas scenarios and correspond to the 10th-90th percentile of the full scenario distribution. Note: CO_2 emissions in most models do not include emissions from decay of above ground biomass that remains after logging and deforestation, and from peat fires and drained peat soils. {Figure 5.1}

There is *high agreement* and *much evidence* that all stabilisation levels assessed can be achieved by deployment of a portfolio of technologies that are either currently available or expected to be commercialised in coming decades, assuming appropriate and effective incentives are in place for their development, acquisition, deployment and diffusion and addressing related barriers. {5.5}

All assessed stabilisation scenarios indicate that 60-80% of the reductions would come from energy supply and use, and industrial processes, with energy efficiency playing a key role in many scenarios. Including non-CO_2 and CO_2 land-use and forestry mitigation options provides greater flexibility and cost-effectiveness. Low stabilisation levels require early investments and substantially more rapid diffusion and commercialisation of advanced low-emissions technologies. {5.5}

Without substantial investment flows and effective technology transfer, it may be difficult to achieve emission reduction at a significant scale. Mobilizing financing of incremental costs of low-carbon technologies is important. {5.5}

The macro-economic costs of mitigation generally rise with the stringency of the stabilisation target (Table SPM.7). For specific countries and sectors, costs vary considerably from the global average.[22] {5.6}

In 2050, global average macro-economic costs for mitigation towards stabilisation between 710 and 445ppm CO_2-eq are between a 1% gain and 5.5% decrease of global GDP (Table SPM.7). This corresponds to slowing average annual global GDP growth by less than 0.12 percentage points. {5.6}

[22] See footnote 17 for more detail on cost estimates and model assumptions.

Table SPM.7. Estimated global macro-economic costs in 2030 and 2050. Costs are relative to the baseline for least-cost trajectories towards different long-term stabilisation levels. {Table 5.2}

Stabilisation levels (ppm CO_2-eq)	Median GDP reduction [a] (%)		Range of GDP reduction [b] (%)		Reduction of average annual GDP growth rates (percentage points) [c], [e]	
	2030	2050	2030	2050	2030	2050
445 – 535 [d]	Not available		< 3	< 5.5	< 0.12	< 0.12
535 – 590	0.6	1.3	0.2 to 2.5	slightly negative to 4	< 0.1	< 0.1
590 – 710	0.2	0.5	-0.6 to 1.2	-1 to 2	< 0.06	< 0.05

Notes: Values given in this table correspond to the full literature across all baselines and mitigation scenarios that provide GDP numbers.
a) Global GDP based on market exchange rates.
b) The 10th and 90th percentile range of the analysed data are given where applicable. Negative values indicate GDP gain. The first row (445-535 ppm CO_2-eq) gives the upper bound estimate of the literature only.
c) The calculation of the reduction of the annual growth rate is based on the average reduction during the assessed period that would result in the indicated GDP decrease by 2030 and 2050 respectively.
d) The number of studies is relatively small and they generally use low baselines. High emissions baselines generally lead to higher costs.
e) The values correspond to the highest estimate for GDP reduction shown in column three.

Responding to climate change involves an iterative risk management process that includes both adaptation and mitigation and takes into account climate change damages, co-benefits, sustainability, equity, and attitudes to risk. {5.1}

Impacts of climate change are *very likely* to impose net annual costs which will increase over time as global temperatures increase. Peer-reviewed estimates of the social cost of carbon[23] in 2005 average US$12 per tonne of CO_2, but the range from 100 estimates is large (-$3 to $95/t$CO_2$). This is due in large part to differences in assumptions regarding climate sensitivity, response lags, the treatment of risk and equity, economic and non-economic impacts, the inclusion of potentially catastrophic losses, and discount rates. Aggregate estimates of costs mask significant differences in impacts across sectors, regions and populations and *very likely* underestimate damage costs because they cannot include many non-quantifiable impacts. {5.7}

Limited and early analytical results from integrated analyses of the costs and benefits of mitigation indicate that they are broadly comparable in magnitude, but do not as yet permit an unambiguous determination of an emissions pathway or stabilisation level where benefits exceed costs. {5.7}

Climate sensitivity is a key uncertainty for mitigation scenarios for specific temperature levels. {5.4}

Choices about the scale and timing of GHG mitigation involve balancing the economic costs of more rapid emission reductions now against the corresponding medium-term and long-term climate risks of delay. {5.7}

[23] Net economic costs of damages from climate change aggregated across the globe and discounted to the specified year.

EXHIBIT 2

Carbon Dioxide Emissions from the Generation of Electric Power in the United States

July 2000

Department of Energy
Washington, DC 20585
Environmental Protection Agency
Washington DC 20460

Contacts

This report was prepared jointly by the staff of the U.S. Department of Energy and the U.S. Environmental Protection Agency. Questions about this publication, as well as other energy inquiries may be directed to the National Energy Information Center on (202) 586-8800.

Questions regarding specific information in the report may be directed as follows:

Electric Power Data and Carbon Dioxide Emission Estimates:

Wiley Barbour (202-260-6972)
e-mail: barbour.wiley@epamail.epa.gov

Channele Carner (202-426-1270)
e-mail: channele.carner@eia.doe.gov

Melvin Johnson (202-426-1172)
e-mail: melvin.johnson@eia.doe.gov

Rick Morgan (202-564-9143)
e-mail: morgan.rick@epamail.epa.gov

Roger Sacquety (202-426-1160)
e-mail: roger.sacquety@eia.doe.gov

Stephen Scott (202-426-1149)
e-mail: stephen.scott@eia.doe.gov

Betty Williams (202-426-1269)
e-mail: betty.williams@eia.doe.gov

Projected Electricity Generation and Carbon Dioxide Emissions:

Scott Sitzer (202-586-2308)
e-mail: scott.sitzer@eia.doe.gov

Voluntary Carbon-Reduction and Carbon-Sequestration Programs:

Paul McArdle (202-586-4445)
e-mail: paul.mcardle@eia.doe.gov

Stephen Calopedis (202-586-1156)
e-mail: stephen.calopedis@eia.doe.gov

Kate Narburgh (202-564-1846)
e-mail: narburgh.kate@epamail.epa.gov

Environmental Effects of Federal Restructuring Legislation:

Tracy Terry (202-586-3383)
e-mail: tracy.terry@hq.doe.gov

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Carbon Dioxide Emissions from the Generation of Electric Power in the United States

Introduction

The President issued a directive on April 15, 1999, requiring an annual report summarizing the carbon dioxide (CO_2) emissions produced by the generation of electricity by utilities and nonutilities in the United States. In response, the U.S. Department of Energy (DOE) and the U.S. Environmental Protection Agency (EPA) jointly submitted the first report on October 15, 1999. This is the second annual report[1] that estimates the CO_2 emissions attributable to the generation of electricity in the United States. The data on CO_2 emissions and the generation of electricity were collected and prepared by the Energy Information Administration (EIA), and the report was jointly written by DOE and EPA to address the five areas outlined in the Presidential Directive.

- The emissions of CO_2 are presented on the basis of total mass (tons) and output rate (pounds per kilowatthour). The information is stratified by the type of fuel used for electricity generation and presented for both regional and national levels. The percentage of electricity generation produced by each fuel type or energy resource is indicated.

- The 1999 data on CO_2 emissions and generation by fuel type are compared to the same data for the previous year, 1998. Factors contributing to regional and national level changes in the amount and average output rate of CO_2 are identified and discussed.

- The Energy Information Administration's most recent projections of CO_2 emissions and generation by fuel type for 1999 are compared to the actual data summarized in this report to identify deviations between projected and actual CO_2 emissions and electricity generation.

- Information for 1998 on voluntary carbon-reducing and carbon-sequestration projects reported by the electric power sector and the resulting amount of CO_2 reductions are presented. Included are programs undertaken by the utilities themselves as well as programs supported by the Federal government to support voluntary CO_2 reductions.

- Appropriate updates to the Department of Energy's estimated environmental effects of the Administration's proposed restructuring legislation are included.

Electric Power Industry CO_2 Emissions and Generation Share by Fuel Type

In 1999,[2] estimated emissions of CO_2 in the United States resulting from the generation of electric power were 2,245 million metric tons,[3] an increase of 1.4 percent from the 2,215 million metric tons in 1998. The estimated generation of electricity from all sources increased by 2.0 percent, going from 3,617 billion kilowatthours to 3,691 billion kilowatthours. Electricity generation from coal-fired plants, the primary source of CO_2 emissions from electricity generation, was nearly the same in 1999 as in 1998. Much of the increase in electricity generation was produced by gas-fired plants and nuclear plants. The 1999 national average output rate,[4] 1.341 pounds of CO_2 per kilowatthour generated, also showed a slight change from 1.350 pounds CO_2 per kilowatthour in 1998 (Table 1). While the share of total generation provided by fossil

[1] The Presidential directive required the first report by October 15, 1999, and thereafter the report is required by June 30. See Appendix A for the full text of the directive.

[2] Data for 1999 are preliminary. Data for 1998 are final. Last year, 1998 data were preliminary and have been revised to final numbers.

[3] To convert metric tons to short tons, multiply by 1.1023. Carbon dioxide units at full molecular weight can be converted into carbon units by dividing by 44/12.

[4] The average output rate is the ratio of pounds of carbon dioxide emitted per kilowatthour of electricity produced from all energy sources, both fossil and nonfossil, for a region or the Nation.

fuels rose slightly, a reduction in the emission rate for coal-fired generation combined with growth in the market share of gas-fired generation contributed to the modest improvement in the output rate.[5]

In the United States, about 40.5 percent[6] of anthropogenic CO_2 emissions was attributed to the combustion of fossil fuels for the generation of electricity in 1998, the latest year for which all data are available.[7] The available

Table 1. Summary of Carbon Dioxide Emissions and Net Generation in the United States, 1998 and 1999

	1998	1999 [p]	Change	Percent Change
Carbon Dioxide (thousand metric tons)[a]				
Coal	1,799,762	1,787,910	-11,852	-0.66
Petroleum	110,244	106,294	-3,950	-3.58
Gas	291,236	337,004	45,768	15.72
Other Fuels [b]	13,596	13,596	–	–
U.S. Total	**2,214,837**	**2,244,804**	**29,967**	**1.35**
Generation (million kWh)				
Coal	1,873,908	1,881,571	7,663	0.41
Petroleum	126,900	119,025	-7,875	-6.21
Gas	488,712	562,433	73,721	15.08
Other Fuels [b]	21,747	21,749	2	–
Total Fossil-fueled	**2,511,267**	**2,584,779**	**73,512**	**2.93**
Nonfossil-fueled [c]	**1,105,947**	**1,106,294**	**347**	**0.03**
U.S. Total	**3,617,214**	**3,691,073**	**73,509**	**2.04**
Output Rate [d] (pounds CO_2 per kWh)				
Coal	2.117	2.095	-0.022	-1.04
Petroleum	1.915	1.969	0.054	2.82
Gas	1.314	1.321	0.007	0.53
Other Fuels [b]	1.378	1.378	–	–
U.S. Average	**1.350**	**1.341**	**-0.009**	**-0.67**

[a] One metric ton equals one short ton divided by 1.1023. To convert carbon dioxide to carbon units, divide by 44/12.

[b] Other fuels include municipal solid waste, tires, and other fuels that emit anthropogenic CO_2 when burned to generate electricity. Nonutility data for 1999 for these fuels are unavailable; 1998 data are used.

[c] Nonfossil includes nuclear, hydroelectric, solar, wind, geothermal, biomass, and other fuels or energy sources with zero or net zero CO_2 emissions. Although geothermal contributes a small amount of CO_2 emissions, in this report it is included in nonfossil.

[d] U.S. average output rate is based on generation from all energy sources.

[P] = Preliminary data.

– = No change.

Note: Data for 1999 are preliminary. Data for 1998 are final.

Sources: •Energy Information Administration, Form EIA-759, "Monthly Power Plant Report"; Form EIA-767, "Steam-Electric Plant Operation and Design Report"; Form EIA-860B, "Annual Electric Generator Report – Nonutility"; and Form 900, "Monthly Nonutility Power Report." •Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

[5] Caution should be taken when interpreting year-to-year changes in the estimated emissions and generation due to an undetermined degree of uncertainty in statistical data for the 1999 estimates. Also, differences in the 1998 and 1999 estimation methodologies have an undetermined effect on the change from 1998 to 1999 estimates. See Appendix B, "Data Sources and Methodology," for further information. For more information on uncertainty in estimating carbon dioxide emissions, see Appendix C, "Uncertainty in Emissions Estimates," *Emissions of Greenhouse Gases in the United States*, DOE/EIA-0573(98) (Washington, DC, October 1999). Also, because weather fluctuations and other transitory factors significantly influence short-run patterns of energy use in all activities, emissions growth rates calculated over a single year should not be used to make projections of future emissions growth.

[6] About 37 percent of CO_2 emissions are produced by electric utility generators, as reported in the greenhouse gas inventory for 1998. An additional 3.5 percent are attributable to nonutility power producers, which are included in the industrial sector in the GHG inventory.

[7] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1998*, Chapter 2, "Carbon Dioxide Emissions," DOE/EIA-0573(98) (Washington, DC, October 1999). Data for 1999 will be available in October 2000.

energy sources used for electricity generation result in varying output rates for CO_2 emissions from region to region across the United States. Although all regions use some fossil fuels for electricity generation, several States generate almost all electricity at nuclear or hydroelectric plants, resulting in correspondingly low output rates of CO_2 per kilowatthour. For example, Vermont produces mostly nuclear power, while Washington, Idaho, and Oregon generate almost all electricity at hydroelectric plants. At the other extreme, Colorado, Indiana, Iowa, Kentucky, New Mexico, North Dakota, Ohio, West Virginia, and Wyoming—a group that includes some of the Nation's largest coal-producing States—generate most of their electricity with coal. Regions where coal-fired generators dominate the industry show the highest rates of CO_2 emissions per kilowatthour.

Coal

Estimated emissions of CO_2 produced by coal-fired generation of electricity were 1,788 million metric tons in 1999 (Table 1), 0.7 percent less than in 1998, while electricity generation from coal was 0.4 percent more than the previous year. The divergent direction of generation and emissions changes may reflect a combination of thermal efficiency improvements, changes in average fuel characteristics, and variances associated with both sampling and nonsampling errors. CO_2 emissions from coal-fired electricity generation comprise nearly 80 percent of the total CO_2 emissions produced by the generation of electricity in the United States, while the share of electricity generation from coal was 51.0 percent in 1999 (Table 3). Coal has the highest carbon intensity among fossil fuels, resulting in coal-fired plants having the highest output rate of CO_2 per kilowatthour. The national average output rate for coal-fired electricity generation was 2.095 pounds CO_2 per kilowatthour in 1999 (Table 4).

Coal-fired generation contributes over 90 percent of CO_2 emissions in the East North Central, West North Central, East South Central, and Mountain Census Divisions and 84 percent in the South Atlantic Census Division (Table 2). Nearly two-thirds of the Nation's CO_2 emissions from electricity generation are accounted for by the combustion of coal for electricity generation in these five regions where most of the Nation's coal-producing States are located. Consequently, these regions have relatively high output rates of CO_2 per kilowatthour.

Table 2. Estimated Carbon Dioxide Emissions From Generating Units at U.S. Electric Plants by Census Division, 1998 and 1999
(Thousand Metric Tons)

Census Division	1998					1999				
	Total	Coal	Petroleum	Gas	Other[a]	Total	Coal	Petroleum	Gas	Other[a]
New England	50,450	16,470	23,068	7,966	2,945	52,822	14,637	24,224	11,015	2,945
Middle Atlantic	189,023	139,821	17,315	28,441	3,447	190,214	134,528	15,232	37,007	3,447
East North Central	427,580	410,141	4,351	12,039	1,049	423,063	397,266	5,415	19,333	1,049
West North Central	217,123	209,858	1,521	4,726	1,018	219,104	208,786	1,957	7,342	1,018
South Atlantic	445,435	373,780	43,777	24,515	3,363	452,180	378,018	41,356	29,442	3,363
East South Central	226,749	212,350	5,018	9,299	82	228,240	214,486	3,212	10,460	82
West South Central	364,056	214,544	5,461	143,945	106	380,792	221,309	5,744	153,634	106
Mountain	219,147	206,256	888	12,002	*	217,543	202,421	1,278	13,843	*
Pacific Contiguous	64,668	14,555	2,588	46,165	1,360	70,591	14,563	2,153	52,515	1,360
Pacific Noncontiguous	10,606	1,985	6,257	2,138	225	10,256	1,895	5,724	2,413	225
U.S. Total	**2,214,837**	**1,799,762**	**110,244**	**291,236**	**13,596**	**2,244,804**	**1,787,910**	**106,294**	**337,004**	**13,596**

[a] Other fuels include municipal solid waste, tires, and other fuels that emit anthropogenic CO_2 when burned to generate electricity. Nonutility data for 1999 for these fuels are unavailable; 1998 data are used.

* = the absolute value is less than 0.5.

Note: Data for 1999 are preliminary. Data for 1998 are final.

Sources: • Energy Information Administration, Form EIA-759, "Monthly Power Plant Report"; Form EIA-767, "Steam-Electric Plant Operation and Design Report"; Form EIA-860B, "Annual Electric Generator Report – Nonutility"; Form EIA-900, "Monthly Nonutility Power Report." • Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 3. Percent of Electricity Generated at U.S. Electric Plants by Fuel Type and Census Division, 1998 and 1999
(Percent)

Census Division	1998					1999				
	Coal	Petroleum	Gas	Other[a]	Nonfossil	Coal	Petroleum	Gas	Other[a]	Nonfossil
New England	17.9	24.4	13.8	4.6	39.3	16.3	22.9	18.0	4.6	38.3
Middle Atlantic	38.4	5.2	13.6	1.3	41.5	35.8	4.5	17.5	1.3	40.9
East North Central	76.3	0.8	3.8	0.4	18.8	72.0	0.7	4.4	0.4	22.5
West North Central	75.5	0.7	2.3	0.3	21.1	73.9	0.7	3.0	0.3	22.0
South Atlantic	55.3	7.2	6.6	0.7	30.2	55.5	6.7	7.8	0.7	29.2
East South Central	66.2	2.1	3.2	*	28.4	68.0	1.4	3.9	*	26.7
West South Central	39.1	0.6	42.2	0.3	17.8	40.1	0.7	44.6	0.3	14.3
Mountain	67.9	0.2	6.8	0.1	25.0	67.5	0.3	8.1	0.1	24.1
Pacific Contiguous	4.3	0.7	23.1	0.4	71.4	4.2	0.5	26.2	0.4	68.7
Pacific Noncontiguous	12.2	52.3	21.3	1.9	12.4	11.7	52.2	24.8	1.9	9.4
U.S. Total	**51.8**	**3.5**	**13.5**	**0.6**	**30.6**	**51.0**	**3.2**	**15.2**	**0.6**	**30.0**

[a] Other fuels include municipal solid waste, tires, and other fuels that emit anthropogenic CO_2 when burned to generate electricity. Nonutility data for 1999 for these fuels are unavailable; 1998 data are used.

* = the absolute value is less than 0.05.

Note: Data for 1999 are preliminary. Data for 1998 are final.

Sources: • Energy Information Administration, Form EIA-759, "Monthly Power Plant Report"; Form EIA-767, "Steam-Electric Plant Operation and Design Report"; Form EIA-860B, "Annual Electric Generator Report – Nonutility"; Form EIA-900, "Monthly Nonutility Power Report." • Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 4. Estimated Carbon Dioxide Emissions Rate From Generating Units at U.S. Electric Plants by Census Division, 1998 and 1999
(Pounds per Kilowatthour)

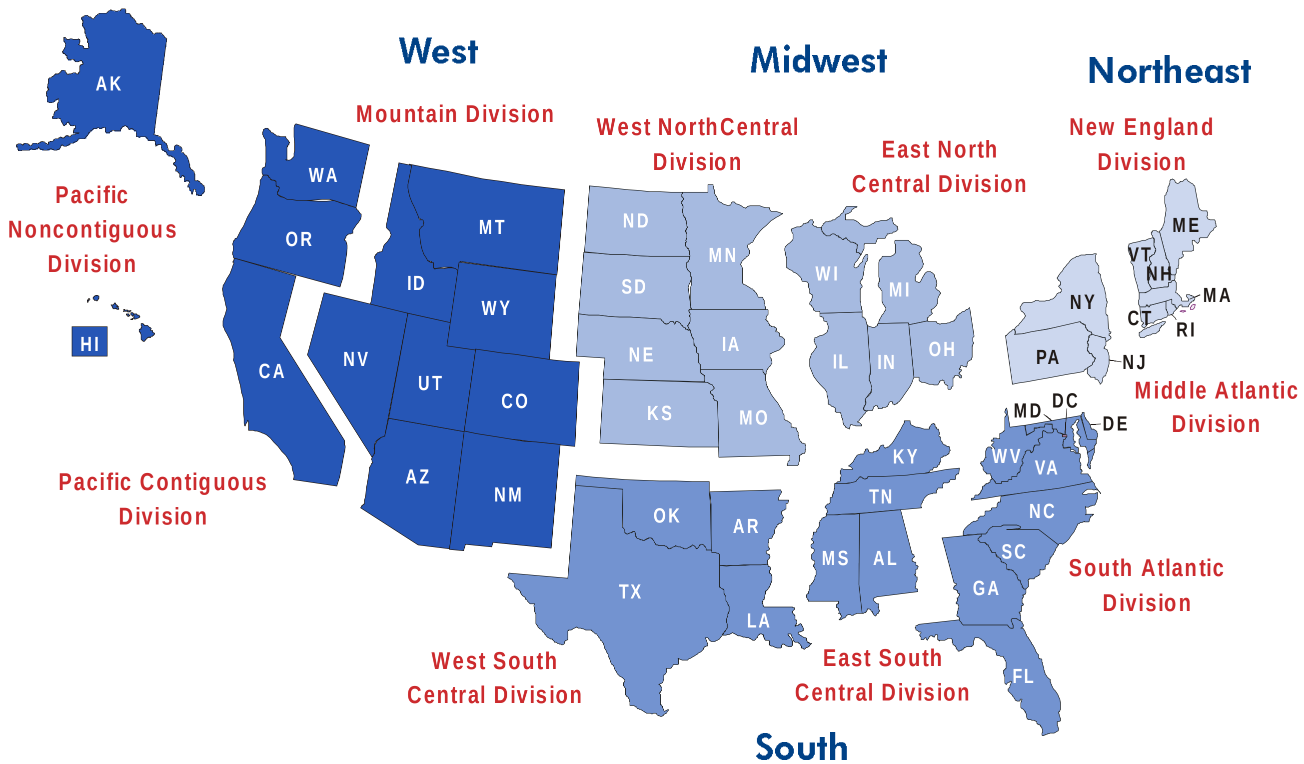
Census Division	1998					1999				
	Total	Coal	Petroleum	Gas	Other[a]	Total	Coal	Petroleum	Gas	Other[a]
New England	1.059	1.934	1.984	1.213	1.339	1.077	1.827	2.156	1.250	1.328
Middle Atlantic	1.071	2.062	1.884	1.188	1.502	1.058	2.089	1.872	1.178	1.502
East North Central	1.680	2.113	2.244	1.239	1.124	1.579	2.061	2.759	1.630	1.131
West North Central	1.767	2.262	1.759	1.659	2.422	1.746	2.250	2.207	1.958	2.596
South Atlantic	1.334	2.026	1.821	1.113	1.377	1.342	2.019	1.822	1.115	1.372
East South Central	1.457	2.060	1.515	1.857	3.244	1.470	2.031	1.530	1.734	3.244
West South Central	1.469	2.214	3.955	1.376	0.151	1.529	2.215	3.170	1.382	0.151
Mountain	1.572	2.179	2.802	1.257	0.005	1.542	2.128	3.036	1.214	0.005
Pacific Contiguous	0.417	2.158	2.396	1.287	2.140	0.435	2.152	2.419	1.238	2.108
Pacific Noncontiguous	1.453	2.229	1.641	1.375	1.661	1.393	2.209	1.488	1.319	1.661
U.S. Average	**1.350**	**2.117**	**1.915**	**1.314**	**1.378**	**1.341**	**2.095**	**1.969**	**1.321**	**1.378**

[a] Other fuels include municipal solid waste, tires, and other fuels that emit anthropogenic CO_2 when burned to generate electricity. Nonutility data for 1999 for these fuels are unavailable; 1998 data are used.

Note: Data for 1999 are preliminary. Data for 1998 are final.

Sources: • Energy Information Administration, Form EIA-759, "Monthly Power Plant Report"; Form EIA-767, "Steam-Electric Plant Operation and Design Report"; Form EIA-860B, "Annual Electric Generator Report – Nonutility"; Form EIA-900, "Monthly Nonutility Power Report." • Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Figure 1. Census Regions and Divisions



Note: Map not to scale.
Source: Adapted from U.S. Department of Commerce, Bureau of the Census, *Statistical Abstract of the United States, 1998* (Washington, DC, October 1998), Figure 1.

Petroleum

CO_2 emissions from petroleum-fired electricity generation were 106 million metric tons in 1999, 3.6 percent less than in 1998. Generation of electricity from petroleum-fired plants decreased from 127 billion kilowatthours in 1998 to 119 billion kilowatthours in 1999. CO_2 emissions from petroleum-fired electricity generation accounted for 4.7 percent of the national total, while generation from petroleum plants was 3.2 percent of the Nation's total electricity generation. The national average output rate for all petroleum-fired generation was 1.969 pounds CO_2 per kilowatthour in 1999.

The New England Census Division generates about one-fourth of its electricity at petroleum-fired plants which produce approximately 45 percent of that region's CO_2 emissions. The Pacific Noncontiguous Census Division generates about one-half of its electricity at petroleum-fired plants, producing about one-half of the region's CO_2 emissions. The South Atlantic and Middle Atlantic Census Divisions also use some petroleum for electricity generation, particularly in Florida. The South Atlantic Census Division contributes the largest share of CO_2 emissions from petroleum-fired plants, 1.8 percent of the Nation's total CO_2 emissions from all sources.

Natural Gas

Emissions of CO_2 from the generation of electricity at natural gas-fired plants were 337 million metric tons in 1999. Natural gas-fired plants were the only fossil-fueled plants to substantially increase generation from 1998 to 1999. Generation increased an estimated 15.0 percent, with CO_2 emissions increasing a corresponding 15.7 percent. Emissions of CO_2 from natural gas-fired plants represented 15.0 percent of total CO_2 emissions from electricity generation in 1999, while natural gas-fired electricity generation accounted for 15.2 percent of total generation. The output rate for CO_2 from natural gas-fired plants in 1999 was 1.321 pounds CO_2 per kilowatthour. Natural gas is the least carbon-intensive fossil fuel.

The West South Central Census Division, which includes Texas, Oklahoma, and Louisiana, is where much of the Nation's natural gas-fired capacity is located. The Northeast and Pacific Contiguous Census Divisions also use natural gas to generate a substantial portion of their electricity. About 40.4 percent of the West South Central Division's CO_2 emissions from the generation of electricity comes from gas-fired plants, representing approximately 45.6 percent of all CO_2 emissions from natural gas combustion for electricity generation in the Nation. About three-fourths of the Pacific Contiguous Census Division's CO_2 emissions are from natural gas-fired plants; however, most of that division's electricity generation is produced at nonfossil-fueled plants, such as hydroelectric and nuclear plants.

Nonfossil Fuels

Nonfossil-fueled generation from nuclear, hydroelectric, and other renewable sources (wind, solar, biomass, and geothermal) represented about 30.0 percent of total electricity generation in 1999 and 30.6 percent in 1998. The use of nonfossil fuels and renewable energy sources to generate electricity avoids the emission of CO_2 that results from the combustion of fossil fuels. Due to lower marginal costs, nuclear and hydroelectric power generation typically displace fossil-fueled electricity generation.

Nuclear plants increased their output by 8.1 percent in 1999 as several plants in the East North Census Division returned to service, contributing to a record capacity factor of 86 percent for nuclear plants in 1999.[8] Nuclear energy provided 19.7 percent of the Nation's electricity in 1999.[9] Two-thirds of the Nation's nuclear power is generated in the New England, East North Central, South Atlantic, and Middle Atlantic Census Divisions, which generate 27.6 percent, 21.0 percent, 26.0 percent, and 35.6 percent, respectively, of their electricity with nuclear power.

More than one-half of the Nation's hydroelectric capacity is located in the Pacific Contiguous Census Division, which includes California, Oregon, and Washington. In the Mountain Census Division, Idaho generates virtually all of its electricity at hydroelectric plants. The availability of hydroelectric power is affected by both the amount and patterns of precipitation. High snowpack levels in the Northwest increased hydroelectric generation in Washington and Oregon during 1999, despite the fact that on an annual basis both States received less precipitation in 1999 than they did in 1998. However, the remainder of the Nation experienced dry conditions in 1999, decreasing the amount of hydroelectric power available to displace fossil-fueled generation.[10]

Factors Contributing to Changes In CO_2 Emissions and Generation

The primary factors that alter CO_2 emissions from electricity generation from year to year are the growth in demand for electricity, the type of fuels or energy sources used for generation, and the thermal efficiencies of the power plants. A number of contributing factors influencing the primary factors can also be identified: economic growth, the price of electricity, the amount of imported electricity, weather, fuel prices, and the amount of available generation from hydroelectric, renewable, and nuclear plants. Other contributing factors include demand-side management programs that encourage energy efficiency, strategies to control other air emissions to comply with the requirements for the Clean Air Act Amendments of 1990, and the installation of new capacity utilizing advanced technologies to increase plant efficiency, such as combined-cycle plants and combined heat and power projects. Annual changes in CO_2 emissions are a net result of these complex and variable factors.

As estimated in this report, the amount of anthropogenic CO_2 emissions attributable to the generation of electricity in the United States increased 1.4 percent since the previous year. In 1999, fossil-fueled generation increased by about 2.9 percent; however, almost all of the increase was associated with natural gas, the least carbon-intensive fossil fuel. The increase in CO_2 emissions from the combustion of natural gas for electricity generation

[8] Capacity factor is the ratio of the amount of electricity produced by a generating plant for a given period of time to the electricity that the plant could have produced at continuous full-power operation during the same period. Based on national level consumption and generation data presented in the *Electric Power Monthly*, and assuming a net summer nuclear capability of 99,000 MW, a 1-percent increase in the annual nuclear plant capacity factor (equivalent to 8,672,400 megawatthours of additional nuclear generation) translates into a reduction in annual consumption of either 4.4 million short tons of coal, 14 million barrels of petroleum, or 92 billion cubic feet of gas, or most likely a combination of each.

[9] Energy Information Administration, *Electric Power Annual 1999, Volume I*, DOE/EIA-0348(99)/1 (Washington, DC, forthcoming).

[10] Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants, 1999*, http://www.eia.doe.gov/cneaf/electricity/cq/cq_sum.html.

amounted to 46 million metric tons, while the CO_2 emissions from the combustion of petroleum and coal decreased 16 million metric tons.

The national average output rate declined from 1.350 pounds of CO_2 per kilowatthour in 1998 to 1.341 pounds CO_2 per kilowatthour in 1999. The primary driver of this change was the decreased output rate for coal-fired electricity generation, which went from 2.117 pounds of CO_2 per kilowatthour to 2.095 pounds of CO_2 per kilowatthour. A change in the output rate for coal-fired electricity generation in the absence of significant change in non-emitting generation will have the greatest effect on the national average output rate of CO_2 per kilowatthour both because coal-fired generation dominates the industry and is the most carbon-intensive fuel.

Economic Growth

Economic factors influence the demand for electric power. In 1999, a strong economy was measured by the 4.2-percent increase in the Gross Domestic Product (GDP).[11] Electricity consumption grew by 1.7 percent,[12] while the average national price of electricity decreased 2.1 percent, from 6.74 cents in 1998 to 6.60 cents in 1999.[13] Although the growing demand for electricity is primarily met by a corresponding growth in generation, a small amount is met by imported power, primarily from Canada.

Weather

Weather is another factor affecting the year-to-year changes in the demand for electricity. Both 1999 and 1998 were record-breaking years in terms of warm weather in the United States. The availability of hydroelectric power to displace fossil-fueled power was limited by dry conditions in much of the Nation, with the exception of the Pacific Northwest States.

During the summer months, the demand for power for air conditioning is a major factor in setting record high peak demands for some utilities. In 1999, electricity generating plants consumed almost as much coal as the record amount consumed in 1998 and increased their natural gas consumption to meet the continuing high demand for electricity in the summer of 1999.

Demand-Side Management (DSM)

Energy efficiency programs and DSM activities, such as improving insulation and replacing lighting and appliances with more energy efficient equipment, can reduce the demand for electricity. The reductions in demand achieved by DSM programs contribute to avoided CO_2 emissions. In 1998, 49.2 billion kilowatthours of energy savings were achieved by DSM activities at electric utilities, a decrease from 56.4 billion kilowatthours in 1997. Declining levels of energy savings reflect, in part, lower utility spending on DSM programs. In 1998, utilities' total expenditures on DSM were $1.4 billion, a decrease of 13.1 percent from the previous year, and nearly 50 percent below the 1994 spending level.[14] Data for 1999 are not yet available.

Fossil and Nonfossil Fuels for Electricity Generation

The fuel or energy source used to generate electricity is the most significant factor affecting the year-to-year changes in CO_2 emissions. Because hydroelectric and nuclear generation displace fossil-fueled generation when available, CO_2 emissions increase when hydroelectric or nuclear power is unavailable and fossil-fueled generation is used as a replacement. Conversely, CO_2 emissions can be reduced through a greater use of nuclear, hydroelectric, and renewable energy for electricity generation. Collectively, nonfossil-fueled electricity generation by nuclear, hydroelectric, and renewable energy sources that do not contribute to anthropogenic CO_2 emissions remained almost unchanged in 1999 as compared to 1998, with much of the increase in nuclear generation being offset by an absolute decrease in hydroelectric power generation and other generation from fuels such as municipal solid waste, tires, and other fuels that emit anthropogenic CO_2 when burned to generate electricity.

As stated previously, the amount of available hydroelectric power is affected by precipitation patterns. In 1999, hydroelectric power generation was lower in all regions, except in the Northwestern States. Oregon, Idaho, and Washington typically generate more than 90 percent of their power at hydroelectric plants and export power to California. Hydroelectric power generation

[11] http://www.bea.doc.gov/bea/dn1.htm, Department of Commerce web site, accessed May 10, 2000.

[12] Retail sales by utilities grew 1.73 percent from 1998 to 1999. Retail sales by marketers in deregulated, competitive retail markets are not included. The addition of an estimated 48 billion kilowatthours in retail marketer sales would result in an increase in electricity consumption of 2.45 percent from 1998 to 1999.

[13] Energy Information Administration, *Electric Power Annual 1999, Volume I,* DOE/EIA-0348(99)/1 (Washington, DC, forthcoming).

[14] DSM data for 1999 will be available in the latter part of 2000.

increased in 1999 in these States, reducing the need for fossil-fueled generation and contributed to keeping CO_2 emissions low in the Pacific Contiguous Census Division. Nationally, hydroelectric power generation decreased by 3.6 percent in 1999.

Nuclear power generation increased by 8.1 percent to a record level in 1999, which contributed to keeping CO_2 emissions lower by displacing fossil-fueled generation, particularly in the East North Central Census Division. Several nuclear plants came back online in 1999, helping to increase the average nuclear capacity factor to 86 percent. An absolute increase in the amount of nuclear power more than offset the loss of some hydroelectric power in 1999.

Fuel Quality and Price

The amount of CO_2 emissions from the combustion of fossil fuels to generate electricity varies according to the quality of the fuels, defined by their carbon content and the associated heating value (Btu).[15] The Btu content of fuels is a determinant of the number of kilowatthours that can be produced[16] and carbon content is a determinant of the amount of CO_2 released when the fuel is burned. Fossil fuels are categorized as either coal, natural gas and other gaseous fuels, or petroleum and petroleum products. Coal-fired electricity generation has the highest output rate of CO_2 per kilowatthour produced, averaging 2.095 pounds per kilowatthour in 1999. Petroleum-fired electricity generation averaged 1.969 pounds per kilowatthour, and natural gas-fired electricity generation had the lowest rate of 1.321 pounds per kilowatthour. With coal-fired plants generating the majority of electricity in the Nation and having the highest output rate, they produced the greatest share of CO_2 emissions from electricity generation, approximately 80 percent of the total.

Some plants are capable of switching fuels to take advantage of the least expensive or the most available resources. In 1998, the price of crude oil reached its lowest level since 1976, causing the price of petroleum delivered to electric utilities to fall below that of natural gas for the first time since 1993. This factor is important when considering the capability of some electric plants to burn the least expensive of these two fuels. As a result of falling prices in 1998, petroleum-fired generation was higher in 1998 than in 1997. However during 1999, the price of petroleum began to increase, and generation from petroleum plants declined. Petroleum has a higher output rate of CO_2 than natural gas; therefore, switching from petroleum to natural gas can have a beneficial effect on both the overall amount and output rate of CO_2 emissions.

In 1999, virtually all of the increase in fossil-fueled generation was from natural gas-fired plants. Coal-fired electricity generation was close to unchanged, while petroleum-fired electricity generation fell. Most of the increase in CO_2 emissions from gas-fired plants was offset by the decline in CO_2 emissions from petroleum- and coal-fired plants.

Thermal Efficiencies of Power Plants

CO_2 emissions from electric power generation are influenced by the efficiency with which fossil fuels are converted into electricity. In a typical power plant, about one-third of the energy contained in the fuel is converted into electricity, while the remainder is emitted as waste heat. Substantial improvements in generation efficiency can be achieved in the future through the replacement of traditional power generators with more efficient technologies, such as combined-cycle generators and combined heat and power (CHP) systems. In these types of systems, waste heat is captured to produce additional kilowatthours of electricity or displace energy used for heating or cooling. Both strategies result in lower CO_2 emissions. The national average thermal efficiency of power generation from fossil fuels in 1999 was estimated to be 32.54 percent, slightly higher than the previous year's average of 32.42 percent.[17]

The average thermal efficiency of coal-fired plants went from 33.15 percent to 33.54 percent in 1999. The improvement in efficiency is also reflected in the national average output rate of pounds of CO_2 per kilowatthour. The output rate for coal-fired plants decreased from 2.117 pounds of CO_2 per kilowatthour in 1998 to

[15] Heating value is measured in British thermal units (Btu), a standard unit for measuring the quantity of heat energy equal to the quantity of heat required to raise the temperature of 1 pound of water 1 degree Fahrenheit.

[16] Boiler type and efficiency, capacity factor, and other factors also affect the number of kilowatthours that can be produced at a particular plant.

[17] The thermal efficiency is a ratio of kilowatthours of electricity produced multiplied by 3,412 Btu to the fuel consumed, measured in Btu. This ratio is dependent on the estimated generation and fuel consumption for 1999. Uncertainty and an undetermined degree of variation in both generation and fuel consumption data for the nonutility sector may contribute to an apparent change in the ratio, which should be regarded as a preliminary value at this time.

2.095 in 1999. Petroleum-fired plants and natural gas-fired plants showed slightly lower thermal efficiencies in 1999, with a corresponding change in the output rate. The rate for petroleum-fired plants increased from 1.915 to 1.969 pounds of CO_2 per kilowatthour, and natural gas-fired plants' output rate increased from 1.314 to 1.321 pounds of CO_2 per kilowatthour.

Conclusion

The emission of CO_2 by electric power plants is not controlled because no standards or required reductions currently exist. Some technology is available to limit CO_2 emissions, but it is extremely expensive. The options to limit the emission of CO_2 from electricity generation are to encourage reduction of the overall consumption of electricity through energy efficiency and conservation initiatives, to improve combustion efficiency at existing plants or install new units that employ more efficient technologies, such as combined-cycle units and combined heat and power (CHP) systems, and to replace fossil-fueled generation with nonfossil-fueled alternatives, such as nuclear, hydroelectric, and other renewable energy sources.

Comparison of Projected with Actual CO_2 Emissions and Generation by Fuel Type

Each year, the Energy Information Administration prepares the *Annual Energy Outlook* (AEO), which contains projections of selected energy information. Projections for electricity supply and demand data, including CO_2 emissions and generation by fuel type, are made for the next 20 years. To evaluate the accuracy and usefulness of the forecast, a comparison was made between the latest forecast for 1999 (from the AEO2000) and the estimated actual data for 1999 (Table 5). The near-term projections in the AEO are based on a combination of the partial-year data available when the forecast was prepared, the latest short-term forecast appearing in the *Short-Term Energy Outlook*, and the regional detail contained in the National Energy Modeling System (NEMS). Consequently, comparisons with the actual data for 1999 are not a definitive indicator of the accuracy of the longer-term projections appearing in the AEO. Nevertheless, they do provide a useful preliminary gauge for tracking and measuring the projections against actual data over time.

Total electricity-related CO_2 emissions for fossil fuels in 1999 were 1.4 percent below the projected emissions level, while the actual total generation from fossil fuels was 0.9 percent above the projected generation level. The largest percentage difference between projected and actual generation by fuel (other than for "Other") was for natural gas-fired generation, which was 3.7 percent higher than projected, but with a corresponding difference in CO_2 emissions of 7.7 percent. However, the largest absolute difference between projected and actual CO_2 emissions by fuel was for coal-fired generation, whose emissions were 75 million metric tons, or 4.0 percent, below the projected level, even while generation was 0.2 percent higher. Three primary factors contribute to the divergence in projected and actual CO_2 emissions:

- **Efficiency of generating units**. Average generating efficiencies for coal-fired capacity were higher in 1999 than those assumed by NEMS, on the order of about 4 percent. On the other hand, the efficiency of natural gas-fueled capacity was about 4 percent lower than the NEMS assumptions. Because coal-fired units produce more than three times the generation of natural gas-fired generators, the impact of the higher efficiencies of coal-burning capacity outweighs the lower actual efficiencies for natural gas capacity. Efficiencies for petroleum-based generation, a much smaller share of overall supply, were 5.6 percent lower than the NEMS assumptions.

- **Total generation requirements**. Overall electricity generation was 1.6 percent higher in 1999 than projected. This was due to the combined effects of higher sales, lower imports, and higher losses for electricity than expected. The incremental generation requirements were met in part by higher natural gas-fired generation, as well as greater reliance on nonfossil sources of electricity such as nuclear and renewables. To the extent that natural gas-fired generation was above the forecast, higher CO_2 emissions resulted.

- **Increased nuclear and hydroelectric generation**. Nuclear generation was 30 billion kilowatthours, or 5.7 percent, above the projected levels in 1999. The difference was due primarily to improving performance of nuclear generating units, beyond that assumed in the projections. Also, hydroelectric generation was 13 billion kilowatthours, or 4.3 percent, above projections. Given the same overall level of generation, higher nuclear and hydroelectric projections would have resulted in less projected

Table 5. U.S. Electric Power Industry Projected and Actual Carbon Dioxide Emissions and Generation, 1999

	Projected	Actual	Percentage Difference
CO_2 Emissions (million metric tons)			
Coal	1,863	1,788	-4.0
Petroleum	100	106	6.0
Natural Gas, Refinery and Still Gas	313	337	7.7
Other[a]	--	14	N/A
Total CO_2 Emissions	**2,277**	**2,245**	**-1.4**
Generation (billion kWh)			
Coal	1,878	1,882	0.2
Petroleum	121	119	-1.7
Natural Gas, Refinery and Still Gas	542	562	3.7
Other[a]	20	22	10.0
Non-Fossil Fuels [b]	1,072	1,106	3.2
Total Generation	**3,632**	**3,691**	**1.6**
Net Imports	47	29	-38.0
Total Electricity Supply	**3,679**	**3,720**	**1.1**
Retail Electricity Sales by Utilities (billion kWh)	3,288	3,296	0.2
Nonutility Generation for Own Use/Sales (billion kWh)[c]	173	165	-4.6
Losses and Unaccounted For (billion kWh)	218	259	18.8

[a]Other fuels include municipal solid waste (MSW), tires, and other fuels that emit anthropogenic CO_2 when burned to generate electricity. MSW generation represents the largest share of this category. MSW projections in the *Annual Energy Outlook 2000* are assumed to have zero net CO_2 emissions. Due to a change in the accounting for MSW by the Environmental Protection Agency, future AEOs will estimate the CO_2 emissions attributed to the non-biomass portion of this fuel. If this had been done for the AEO2000, CO_2 emissions for MSW would have been 14 million metric tons for 1999.

[b]Includes nuclear and most renewables, which either do not emit CO_2 or whose net CO_2 emissions are assumed to be zero.

[c]Data for 1999 are estimated.

Note: Actual data for CO_2 emissions and electricity generation for 1999 are preliminary. Components may not add to total due to independent rounding.

Sources: **Projections**: Energy Information Administration, *Annual Energy Outlook 2000*, DOE/EIA-0383 (2000) (Washington, DC, December 1999) and supporting runs of the National Energy Modeling System. **Actual**: Carbon dioxide emissions and generation: Table 1; other data: Energy Information Administration, *Monthly Energy Review, April 2000*, DOE/EIA-0035(2000/04) (Washington, DC, April 2000); Energy Information Administration, *Short-Term Energy Outlook*, May 2000 (EIA Web site, www.eia.doe.gov/emeu/steo/pub/contents.html).

generation from fossil fuels, thus bringing electricity-related CO_2 emissions more in line with actual data.

Voluntary Carbon-Reduction and Carbon-Sequestration Programs

Both the DOE and the EPA operate voluntary programs for reducing greenhouse gas emissions and reporting such emission reductions. Voluntary programs that contribute to emission reductions in the electricity sector include DOE / EIA's Voluntary Reporting of Greenhouse Gases Program and EPA's ENERGY STAR program.

EIA's Voluntary Reporting of Greenhouse Gases Program collects information from organizations that have undertaken carbon-reducing or carbon-sequestration projects. Most of the electric utilities that report to the Voluntary Reporting Program also participate in voluntary emission reduction activities through DOE's Climate Challenge Program. In 1998, as part of the Voluntary Reporting Program, 120 organizations in the electric power sector reported on 1,166 projects undertaken in 1998.[18] By undertaking these projects, participants indicated that they reduced CO_2 emissions by 165.8 million metric tons[19] (Table 6). The organizations almost universally measured their project-level reductions by comparing emissions with what they would have been in the absence of the project. Reported CO_2 reductions from these projects accounted for 7.5 percent of 1998 CO_2 emissions attributed to the generation of electric power in the United States. Foreign reductions, largely from carbon-sequestration projects, account for 6.0 percent of total electric utility sector reductions reported for 1998.

DOE's Climate Challenge Program, a voluntary initiative with the electric utility sector established under the President's 1993 Climate Change Action Plan, has become the principal mechanism by which electric utilities participate in voluntary emission reduction activities. Participants that reported the CO_2 emission reductions summarized in this report include electric utilities and holding companies, independent power producers, and landfill methane operators. Climate Challenge participants negotiate voluntary commitments with the DOE to achieve a certain level of emission reductions and/or to participate in specific projects. Companies making Climate Challenge commitments as of 1998 accounted for about 71 percent of 1990 U.S. electric utility generation.[20] Climate Challenge participants are required to report their achieved emissions reductions to the Voluntary Reporting of Greenhouse Gases Program.

Results from the Climate Challenge program cannot be compared directly to other figures in this report because

Table 6. Electric Power Sector Carbon Dioxide Emission Reductions, 1997 and 1998
(Million Metric Tons Carbon Dioxide)

Type of Reduction	Carbon Dioxide[a]	
	1997	1998
Domestic Reductions		
Emission Reductions Projects	135.9	155.3
Sequestration Projects	0.3	0.5
Total Domestic Reductions	**136.2**	**155.8**
Foreign Reductions		
Emission Reductions Projects	0.1	0.1
Sequestration Projects	9.4	9.9
Total Foreign Reductions	**9.5**	**10.0**
Total CO_2 Reductions Reported	**145.8**	**165.8**

[a]The Voluntary Reporting of Greenhouse Gases Program is currently in the 1999 data reporting cycle; the most recent year for which complete data are available is 1998. The 1997 and 1998 data in last year's report were preliminary and have been revised in this report due to subsequent completion of internal EIA review of those data. Emission reductions also include those reported by landfill methane operators. The use of landfill methane to generate electricity displaces fossil fuel power generation and produces a reduction in CO_2 emissions equivalent to the amount of CO_2 that would have resulted from fossil fuel power generation. In calculating CO_2 reductions, it is assumed that landfill carbon is biogenic and, thus, the CO_2 emissions from landfill gas combustion are zero.

Note: Totals may not equal the sums of the parts due to independent rounding. This data cannot be compared directly to other figures in this report because reporters to EIA's Voluntary Reporting of Greenhouse Gases Program may report emission reductions using baselines and valuation methods different from those applied elsewhere.

Source: Energy Information Administration, Form EIA-1605, "Voluntary Reporting of Greenhouse Gases," (long form) and EIA-1605EZ, "Voluntary Reporting of Greenhouse Gases," (short form), 1997 and 1998 data.

[18] The Voluntary Reporting of Greenhouse Gases Program is currently in the 1999 data reporting cycle; the most recent year for which complete data are available is 1998. The 1997 and 1998 data in last year's report were preliminary and have been revised in this report due to subsequent completion of internal EIA review of those data. Emission reductions also include those reported by landfill methane operators.

[19] The EIA also receives numerous reports on projects and emissions reductions from reporters outside the electric power sector. In addition, many reports submitted to the Voluntary Reporting Program (including electric power sector reports) include reductions of greenhouse gases other than carbon dioxide, such as methane and nitrous oxide and the high Global Warming Potential gases such as HFCs, PFCs and sulfur hexafluoride.

[20] U.S. Department of Energy, Climate Challenge Fact Sheet (1998), and conversation with Larry Mansueti, August 10, 1999. See also http://www.eren.doe.gov/climatechallenge/execsumm/execsumm.htm.

the Climate Challenge program allows participants to report emissions reductions using baselines and calculation methods different from those applied elsewhere. For this reason, EIA keeps an accounting of reports submitted by Climate Challenge participants, but the United States counts only a fraction of these reported reductions in comprehensive assessments of overall reductions in greenhouse gases.[21]

The largest reductions claimed for 1998 are from these major U.S. electric utilities: the Tennessee Valley Authority (26.0 million metric tons of CO_2), TXU (19.9 million metric tons of CO_2), Duke Energy (12.1 million metric tons of CO_2), and FirstEnergy (10.6 million metric tons of CO_2).[22] These four companies accounted for about 41.4 percent of the CO_2 emissions reductions reported in 1998 by the electric power sector. Each of these companies owns one or more nuclear power plants, and the bulk of their reported reductions is calculated by comparing either actual or additional nuclear output from their plants with the emissions that would have occurred if the same quantity of electricity had been generated using fossil fuels.

Electric power industry companies also reported on projects reducing other greenhouse gases.[23] Combining all projects and all greenhouse gases, the electric power sector reporters claimed 176.9 million metric tons of carbon dioxide equivalent reductions in 1998.

Utilities also undertook a number of carbon-sequestration projects. Although these projects do not directly affect CO_2 emissions, they do offset utility CO_2 emissions. Foreign carbon-sequestration projects from the electric sector were reported to be 9.9 million metric tons of CO_2 in 1998, while domestic projects were reported to be 0.5 million metric tons. These activities were dominated by three independent power producer subsidiaries of the AES Corporation, which reported 7.6 million metric tons of CO_2 sequestration annually from three projects with activities in Belize, Bolivia, Ecuador, Peru, and Guatemala. These projects undertake tropical rain forest management, preservation, or reforestation.

In addition, more than 30 companies reported on their pro-rated share of participation in the Edison Electric Institute's UtiliTree program.[24] The UtiliTree program is a carbon-sequestration mutual fund in which electric utilities purchase shares. UtiliTree uses the funds to participate in forest management and reforestation projects in the United States and abroad.

The United States' voluntary programs are reducing domestic emissions of greenhouse gases in a number of sectors across the economy through a range of partnerships and outreach efforts. For example, the ENERGY STAR Program, run by the EPA in partnership with DOE, reduces energy consumption in homes and office buildings across the Nation. EPA and DOE set energy-efficiency specifications for a range of products including office equipment, heating and cooling equipment, residential appliances, televisions and VCRs, and new homes. The ENERGY STAR label for buildings is based on a performance rating system that allows building owners to evaluate the efficiency of their buildings relative to others. On average, buildings across the country can improve efficiency by 30 percent through a variety of improvements. Manufacturer and retailer partners in the program may place the nationally recognized ENERGY STAR label on qualifying products.

In the past several years, the ENERGY STAR label has expanded to include more than 30 products and nearly 7,000 product models. In 1999, energy consumption was reduced by approximately 28 billion kilowatthours as a result of the program, reducing greenhouse gas emissions by nearly 21 million metric tons CO_2 (Table 7). Through EPA's ENERGY STAR Buildings and Green Lights Partnership, more than 15 percent of the square footage in U.S. buildings has undergone efficiency upgrades resulting in electricity savings in excess of 21 billion kilowatthours and emissions reductions of more than 16 million metric tons CO_2.

Environmental Effects of Federal Restructuring Legislation

In April 1999, the Administration submitted to Congress the Comprehensive Electricity Competition Act (CECA), a bill to restructure the U.S. electricity industry and foster retail competition. CECA was designed to ensure

[21] See the *1997 Climate Change Action Report* (the Submission of the United States of America under the United Nations Framework Convention on Climate Change), p. 100, for one such assessment.

[22] TXU was formerly known as Texas Utilities, while FirstEnergy is the result of a merger between Ohio Edison and Centerior Energy (Cleveland Electric).

[23] Other greenhouse gases include methane reductions from landfills and oil and natural gas systems, and sulfur hexafluoride (SF_6), which has 23,900 times the global warming impact of carbon dioxide when released into the atmosphere.

[24] The more than 40 companies referenced in last year's report are participants in EEI's UtiliTree program. Of these companies, 31 reported their share of participation to the Voluntary Reporting of Greenhouse Gases Program for 1998.

Table 7. CO_2 Emission Reductions and Energy Savings from EPA's Voluntary Programs, 1998 and 1999

	1998		1999	
	Million Metric Tons of CO_2 Reduced	Billion kWh Saved	Million Metric Tons of CO_2 Reduced	Billion kWh Saved
ENERGY STAR Labeled Products	14.7	20	20.9	28
ENERGY STAR Buildings and Green Lights	8.8	13	16.5	21
Climate Wise	9.9	3	13.9	5

Source: U.S. Environmental Protection Agency, Climate Protection Division, *1998 Annual Report: Driving Investment in Energy Efficiency, ENERGY STAR and Other Voluntary Programs* (EPA 430-R-99-005), forthcoming.

that the full economic and environmental benefits of electricity restructuring are realized. The expected environmental benefits are the result of both the effects of competition and specific provisions included in the Administration's proposal, such as a renewables portfolio standard, a public benefits fund, and tax incentives for investment in combined heat and power facilities. Competition itself will also provide incentives to generators to improve their own efficiencies, and create new markets for green power and end-use efficiency services, all of which reduce greenhouse gas emissions.

Following an exhaustive interagency review, the DOE issued a *Supporting Analysis*[25] that quantified both the economic and environmental benefits of the Administration's plan in May 1999. The analysis focused on the impacts of full national retail competition relative to continued cost-of-service regulation. The results showed that the Administration's proposal will reduce CO_2 emissions by 216 million metric tons in 2010. An EIA study[26] using the same assumptions from the supporting analysis produced similar results. Carbon dioxide emissions in the EIA report were estimated to be 194 million metric tons lower in the competitive case than in the cost-of-service reference case in 2010. A number of key uncertainties, however, can affect these projections, and some of the reductions could be realized due to actions already taken by individual States. Recognizing uncertainties and the need to avoid double-counting, the Administration projected that its proposal would reduce CO_2 emissions from energy use by 147 to 220 million metric tons annually by 2010.

The DOE and EPA see no recent developments that would change our projection of the expected impact of the Administration proposal. However, we note that restructuring bills that have recently moved forward in the Congress differ significantly from the Administration's comprehensive proposal. These bills do not include key provisions that support the effective functioning of competitive electricity markets and energy diversity while at the same time providing reductions in CO_2 emissions. In addition to maintaining our capability to reassess the impacts of our own proposal, we are also prepared to provide quantitative analyses of alternative restructuring bills. Additional measures could offer potential for cost-effective emissions reductions in the electric power sector, although they are no substitute for comprehensive restructuring legislation that promotes competitive markets and consumer benefits while providing important reductions in CO_2 emissions from electric power generation.

[25] U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Act*, May 1999.

[26] Energy Information Administration, *The Comprehensive Electricity Competition Act: A Comparison of Model Results*. Internet site at http://www.eia.doe.gov/oiaf/servicerpt/ceca.html.

Appendix A

Presidential Directive

April 15, 1999
MEMORANDUM FOR THE
SECRETARY OF ENERGY
ADMINISTRATOR OF THE ENVIRONMENTAL PROTECTION AGENCY

SUBJECT: Report on Carbon Dioxide (CO_2) Emissions

My Administration's proposal to promote retail competition in the electric power industry, if enacted, will help to deliver economic savings, cleaner air, and a significant down payment on greenhouse gas emissions reductions. The proposal exemplifies my Administration's commitment to pursue both economic growth and environmental progress simultaneously.

As action to advance retail competition proceeds at both the State and Federal levels, the Administration and the Congress share an interest in tracking environmental indicators in this vital sector. We must have accurate and frequently updated data.

Under current law, electric power generators report various types of data relating to generation and air emissions to the Department of Energy (DOE) and the Environmental Protection Agency (EPA). To ensure that this data collection is coordinated and provides for timely consideration by both the Administration and the Congress, you are directed to take the following actions:

- On an annual basis, you shall provide me with a report summarizing CO_2 emissions data collected during the previous year from all utility and nonutility electricity generators providing power to the grid, beginning with 1998 data. This information shall be provided to me no more than 6 months after the end of the previous year, and for 1998, within 6 months of the date of this directive.

- The report, which may be submitted jointly, shall present CO_2 emissions information on both a national and regional basis, stratified by the type of fuel used for electricity generation, and shall indicate the percentage of electricity generated by each type of fuel or energy resource. The CO_2 emissions shall be reported both on the basis of total mass (tons) and output rate (e.g., pounds per megawatt-hour).

- The report shall present the amount of CO_2 reduction and other available information from voluntary carbon-reducing and carbon-sequestration projects undertaken, both domestically and internationally, by the electric utility sector.

- The report shall identify the main factors contributing to any change in CO_2 emissions or CO_2 emission rates relative to the previous year on a national, and, if relevant, regional basis. In addition, the report shall identify deviations from the actual CO_2 emissions, generation, and fuel mix of their most recent projections developed by the Department of Energy and the Energy Information Administration, pursuant to their existing authorities and missions.

- In the event that Federal restructuring legislation has not been enacted prior to your submission of the report, the report shall also include any necessary updates to estimates of the environmental effects of my Administration's restructuring legislation.

- Neither the DOE nor the EPA may collect new information from electricity generators or other parties in order to prepare the report.

WILLIAM J. CLINTON

Appendix B

Data Sources and Methodology

This section describes the data sources and methodology employed to calculate estimates of carbon dioxide (CO_2) emissions from utility and nonutility electric generating plants. Due to the report being submitted in June of 2000, the annual census data, on which 1998 emission estimates are based, are not yet available from the Form EIA-860B and Form EIA-767. The methodology employed for estimating 1999 CO_2 emissions in this report are based on two monthly data collections, Form EIA-759 and Form EIA-900. The Form EIA-759 collects monthly generation and fuel consumption from all utility-owned generating plants, and the Form EIA-900 collects generation and fuel consumption from nonutility plants with a nameplate capacity of 50 megawatts (MW) or more. The 1999 estimates of CO_2 emissions and net generation are preliminary estimates; final emissions estimates based on annual census data will be published in the *Electric Power Annual Volume II 1999*, later this year.

Electric Utility Data Sources

The electric utility data are derived from several forms. The Form EIA-767, "Steam-Electric Plant Operation and Design Report," collects information annually for all U.S. power plants with a total existing or planned organic- or nuclear-fueled steam-electric generator nameplate rating of 10 MW or larger. Power plants with a total generator nameplate rating of 100 MW or more must complete the entire form, providing among other data, information about fuel consumption and quality. Power plants with a total generator nameplate rating from 10 MW to less than 100 MW complete only part of the form, including information on fuel consumption.

Form EIA-759, "Monthly Power Plant Report," is a cutoff model sample of approximately 360 electric utilities drawn from the frame of all operators of electric utility plants (approximately 700 electric utilities) that generate electric power for public use. The monthly data collection is from all utilities with at least one plant with a nameplate capacity of 50 MW or more. For all utility plants not included in the monthly sample, those with nameplate capacities less than 50 MW, monthly data are collected annually. Form EIA-759 is used to collect data on net generation; consumption of coal, petroleum, and natural gas; and end-of-the-month stocks of coal and petroleum for each plant by fuel-type combination.

The Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," is a monthly record of delivered-fuel purchases, submitted by approximately 230 electric utilities for each electric generating plant with a total steam-electric and combined-cycle nameplate capacity of 50 MW or more. FERC Form 423 collects data on fuel contracts, fuel type, coal origin, fuel quality and delivered cost of fuel.

Nonutility Data Sources

Form EIA-860B, "Annual Electric Generator Report – Nonutility," (prior Form EIA-867, "Annual Nonutility Power Producer Report") collects information annually from all nonutility power producers with a total generator nameplate rating of 1 MW or more, including cogenerators, small power producers, and other non-utility electricity generators. All facilities must complete the entire form, providing, among other data, information about fuel consumption and quality; however facilities with a combined nameplate capacity of less than 25 MW are not required to complete Schedule V, "Facility Environmental Information," of the Form EIA-860B.

Form EIA-900, "Monthly Nonutility Power Plant Report," is a cutoff model sample of approximately 500 nonutilities drawn from the frame of all nonutility facilities (approximately 2000 nonutilities) that have existing or planned nameplate capacity of 1 MW or more. The monthly data collection comes from all nonutilities with a nameplate rating of 50 MW or more. A cutoff model sampling and estimation are employed using the annual Form EIA-860B.

CO_2 Coefficients

The coefficients for determining carbon released from the combustion of fossil fuels were developed by the

Energy Information Administration. A detailed discussion of the development and sources used is contained in the publication, *Emissions of Greenhouse Gases in the United States*, (DOE/EIA-0573), Appendix B. The nonutility coefficients were developed to be consistent with the utility coefficients.

Methodology for 1998

The methodology for developing the CO_2 emission estimates for steam utility plants and nonsteam utility plants (calculations performed on a plant basis by fuel), as well as for nonutility plants (calculations performed on a facility basis by fuel), is as follows:

Steam Utility Plants

Form EIA-767, "Steam-Electric Plant Operation and Design Report"
Form EIA-759, "Monthly Power Plant Report"
FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants"

Step 1. Sum of Monthly Consumption (EIA-767) times Monthly Average Btu Content (EIA-767) divided by Total Annual Consumption (EIA-767) = Weighted Annual Btu Content Factor.

Step 2. Annual Consumption (EIA-767) times Weighted Annual Btu Content Factor (Step 1) = Annual Btu Consumption.

Step 3. Annual Btu Consumption (Step 2) times CO_2 factors = Annual CO_2 Emissions.

Step 4. Reduce Annual CO_2 Emissions (Step 3) by 1 percent to assume 99 percent burn factor.

Nonsteam Utility Plants

Form EIA-759, "Monthly Power Plant Report"
FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants"

Step 1(a). If monthly EIA-759 and monthly FERC Form 423 are available: Sum of Monthly Consumption (EIA-759) times Monthly Average Btu Content (FERC Form 423) divided by Total Annual Consumption = Weighted Annual Btu Content Factor.

Step 1(b). If monthly EIA-759 is available, but not monthly FERC Form 423: Sum of Monthly Consumption (EIA-759) times Average Monthly Btu Content (calculated from FERC Form 423) divided by Total Annual Consumption = Weighted Annual Btu Content Factor.

Step 1(c). If only annual EIA-759 is available: Annual Consumption (EIA-759) times Average Annual Btu Content (calculated from FERC Form 423) divided by Total Annual Consumption = Weighted Annual Btu Content Factor.

Step 2. Annual Consumption (EIA-759) times Weighted Annual Btu Content Factor (Step 1) = Annual Btu Consumption.

Step 3. Annual Btu Consumption (Step 2) times CO_2 Factors = Annual CO_2 Emissions.

Step 4. Reduce Annual CO_2 Emissions (Step 3) by 1 percent to assume 99 percent burn factor.

Nonutility Plants

Form EIA-860B, "Annual Electric Generator Report – Nonutility"
FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants"

Step 1. Annual Consumption (EIA-860B) times Average Annual Btu Content (EIA-860B) divided by Total Annual Consumption = Weighted Annual Btu Content Factor.

Step 2. Annual Consumption (EIA-860B) times Weighted Annual Btu Content Factor (Step 1) = Annual Btu Consumption.

Step 3. Annual Btu Consumption (Step 2) x CO_2 Factors = Annual CO_2 Emissions.

Step 4. Reduce Annual CO_2 Emissions (Step 3) by 1 percent to assume 99 percent burn factor.

Methodology for 1999

Utility Plants

Form EIA-767, “Steam-Electric Plant Operation and Design Report”
Form EIA-759, “Monthly Power Plant Report”
FERC Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants”

Step 1(a). If monthly EIA-759 and prior year annual EIA-767 are available: Sum of Monthly Consumption (EIA-759) times Monthly Average Btu Content (EIA-767) divided by Total Annual Consumption (EIA-759) = Weighted Annual Btu Content Factor.

Step 1(b). If prior year annual EIA-767 is not available, but monthly EIA-759 and monthly FERC Form 423 are available: Sum the Monthly Consumption (EIA-759) times the Monthly Average Btu Content (FERC Form 423) divided by the Total Annual Consumption (EIA-759) = Weighted Annual Btu Content Factor.

Step 1(c). If prior year annual EIA-767 and monthly FERC Form 423 are not available, but monthly EIA-759 is available: Sum the Monthly Consumption (EIA-759) times the Average Monthly Btu Content (calculated at State level from FERC Form 423) divided by the Total Annual Consumption (EIA-759) = Weighted Annual Btu Content Factor.

Step 1(d). If prior year annual EIA-767, monthly EIA-759 and monthly FERC Form 423 are not available, but only annual EIA-759 is available: Annual Consumption (EIA-759) times the Average Annual Btu Content (calculated at State level from FERC Form 423) divided by the Total Annual Consumption (EIA-759) = Weighted Annual Btu Content Factor.

Step 2. Annual Consumption (EIA-759) times the Weighted Annual Btu Content Factor (Step 1) = Annual Btu Consumption.

Step 3. Annual Btu Consumption (Step 2) times CO_2 Coefficients (*Emissions of Greenhouse Gases in the United States*) = Annual Gross CO_2 Emissions.

Step 4. Reduce Annual Gross CO_2 Emissions (Step 3) by 1 percent to assume 99 percent burn factor.

Nonutility Plants

Form EIA-900, “Monthly Nonutility Power Report”
Form EIA-860B, “Annual Electric Generator Report – Nonutility”
FERC Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants”

Step 1(a). If monthly EIA-900 and prior year annual EIA-860B are available: Sum the Monthly Generation by Census Division and Fuel Type (EIA-900), and apply annual growth factor model to estimate 1999 Annual Generation. Divide 1999 Annual Generation by 1998 Annual Generation (EIA-860B), subtract 1, and multiply by 1998 Total Annual Consumption[27] (EIA-860B) = 1999 Total Annual Consumption. 1999 Total Annual Consumption times Average Btu Content (EIA-860B for prior year) = 1999 Annual Btu Consumption.

Step 1(b). If monthly EIA-900 and FERC Form 423 for 1998 are available: (sold utility plant to nonutility in 1999): Annual Consumption (EIA-900) times the Average Btu Content (FERC Form 423) = 1999 Annual Btu Consumption.

Step 1(c). If only monthly EIA-900 is available (new nonutility plants): Annual Consumption (EIA-900) times the Average Btu Content (calculated at State level from FERC Form 423) = 1999 Annual Btu Consumption.

Step 2. 1999 Annual Btu Consumption (Step 1) times CO_2 Coefficients (*Emissions of Greenhouse Gases in the United States*) = Annual Gross CO_2 Emissions.

Step 3. Reduce Annual Gross CO_2 Emissions (Step 2) by 1 percent to assume 99 percent burn factor.

[27] 1998 Annual Consumption for cogenerators is adjusted to exclude fuel not used for generation of electricity.

EXHIBIT 3

DRAFT
ENVIRONMENTAL IMPACT STATEMENT
FOR THE
BASIN ELECTRIC POWER COOPERATIVE DRY FORK STATION AND HUGHES TRANSMISSION LINE

AUGUST 2007

Prepared For:

United States Department of Agriculture - Rural Utilities Service

USDA Rural Development

USDA, RURAL DEVELOPMENT UTILITIES PROGRAMS
MAIL STOP 1571, ROOM 2240-S
1400 INDEPENDENCE AVE, SW
WASHINGTON, DC 20250

economies" to agree on a global framework for cutting greenhouse gas emissions (http://www.eesi.org/publications/Newsletters/CCNews/8.3.07%20CCNews.htm). Over the last year, both houses of Congress have debated and/or introduced legislation dealing with climate change policy and carbon regulation. It appears likely that these efforts will continue, but their eventual influence on national policy is unknown. As of this writing, the House and Senate continue to develop appropriations bills dealing with energy efficiency and renewable energy.

In February 2002, the United States announced a comprehensive strategy to reduce the greenhouse gas intensity of the American economy by 18 percent from 2002 to 2012. Greenhouse gas intensity is a measurement of greenhouse gas emissions per unit of economic activity. Meeting this commitment will prevent the release of more than 100 million metric tons of carbon-equivalent emissions to the atmosphere (annually) by 2012 and more than 500 million metric tons (cumulatively) between 2002 and 2012.

The EPA plays a significant role in helping the Federal government reach the country's reduction goals and has many current and near-term initiatives that encourage voluntary reductions from a variety of stakeholders. Initiatives, such as ENERGY STAR, Climate Leaders, and Methane Voluntary Programs, encourage emission reductions from large corporations, consumers, industrial and commercial buildings, and many major industrial sectors (EPA 2006e).

In November 2006, the U.S. Supreme Court began to hear arguments in a case to determine whether the EPA should regulate emissions of CO_2 as a pollutant. In April 2007, the court declared that CO_2 and other greenhouse gases are air pollutants under the CAA, and are therefore subject to regulation by the EPA. Although the EPA has not promulgated any regulations for greenhouse gas emissions, numerous methods have been proposed, such as cap and trade programs for large industrial emission sources (e.g. fossil-fueled power plants); improved fuel economy standards for new automobiles; more stringent new source performance standard for stationary sources; business tax incentives for demonstrated GHG emission reductions; increased tax incentives for utilities to include renewable and nuclear fuels in the power generation mix; improved efficiency standards for new buildings; tax-incentives for energy efficient retrofits, etc. Even with the Supreme Court decision, the EPA could still decide not to regulate carbon dioxide, but only if it concludes that such emissions do not contribute to climate change or endanger public health and welfare. If the EPA does decide to draft regulations, they would first need to perform a thorough evaluation of the various alternatives, and this process could take years.

3.6 ACOUSTIC ENVIRONMENT

3.6.1 Noise Terminology

> **Frequency** is the measurement of the number of occurrences of a repeated event per unit of time.

Noise or "unwanted sound" can be intermittent or continuous, steady or impulsive, stationary or transient. Humans or wildlife can be affected by noise either interfering with normal activities or diminishing the quality of the environment. Perception of noise is affected by the intensity, frequency, pitch, and duration, as well as the auditory system and physiology of a particular animal. Noise levels heard by humans or wildlife depend on such variables as distance, percentage and type of ground cover, and objects or barriers between the noise source and the receiver, as well as the atmospheric conditions.

overall emissions; however, the air quality impacts from these pollutant emissions are expected to be minor in magnitude and extent, short-term in duration, and probable. Impacts on Class II regions from construction of the Dry Fork Station would be minor in magnitude, short-term in duration, moderate in extent, and probable.

Operations

Estimated annual emissions are included in the Air Permit Application for all point and fugitive emissions sources from operation of the proposed Dry Fork Station, including the main pulverized coal (PC) boiler, material-transfer systems, and auxiliary equipment. The Dry Fork Station would have material-transfer operations for coal, fly ash, FGD waste, lime, sorbent (activated carbon), and ash disposal. Annual emissions were conservatively estimated based on a 100 percent capacity factor (full load operation for 8,760 hours per year). Detailed emission calculations are provided in the text and in the Air Permit Application (CH2M Hill 2005a).

The combined annual emissions of regulated air pollutants are shown in Table 4.5-3 along with the corresponding PSD significance rates. As this table shows, with the exception of lead, mercury, and hazardous air pollutants (HAPs), regulated pollutant emission rates would exceed annual PSD significance levels.

Table 4.5-3 – Total Annual Emission Rates for Power Plant Operations

Pollutant	Potential Annual Emissions (tpy)	PSD Significance Rate (tpy)	Exceeds PSD Significance
Acid Gases (HF, HCL)	25.0	3	yes
Beryllium	0.004	0.0004	yes
CO	2456	100	yes
Fluorides (as HF)	11.2	3	yes
HAP	9.95	25	no
Lead (Pb)	0.03	0.6	no
Mercury (Hg)	0.047	0.1	no
NO_2	1162	40	yes
PM_{10}	304.1	15	yes
Sulfur Oxides (SO_2)	1626	40	yes
Sulfuric Acid Mist	40.6	7	yes
Volatile Organic Compounds (VOCs)	62.0	40	yes

Source: CH2MHill 2005

In addition to regulated pollutants, power plant operations would produce greenhouse gases, such as Carbon Dioxide (CO_2), methane, and nitrous oxide. The potential CO_2 emissions are 3.7 million tons per year (tpy) (CH2M Hill 2005a). Potential annual methane and nitrous oxide emissions are 25.3 tpy and 58.1 tpy, respectively.

4.5.5 Dry Fork Station BACT Determinations

Best Available Control Technology (BACT) determinations are presented in the Air Permit Application (CH2M Hill 2005a) for the emissions sources at the proposed Dry Fork Station, including the main PC boiler, material-transfer systems, and auxiliary equipment. Basin Electric may elect to install a sorbent injection system, with a material such as activated carbon, to reduce

EXHIBIT 4

REGIONAL GREENHOUSE GAS INITIATIVE

Memorandum of Understanding

WHEREAS, the States of Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont (the "Signatory States") each individually have a policy to conserve, improve, and protect their natural resources and environment in order to enhance the health, safety, and welfare of their residents consistent with continued overall economic growth and to maintain a safe and reliable electric power supply system; and

WHEREAS, there is a growing scientific consensus that the increase in anthropogenic emissions of greenhouse gases is enhancing the natural greenhouse effect resulting in changes in the Earth's climate; and

WHEREAS, climate change poses serious potential risks to human health and terrestrial and aquatic ecosystems globally and in the Signatory States including: more severe droughts and floods; atmospheric warming resulting in increased concentrations of ground-level ozone (smog) and associated adverse health effects; changes in forest composition as dominant plant species change; increases in habitat for disease-carrying insects like mosquitos and other vectors; increases in algal blooms that damage shellfish nurseries and can be toxic to humans; sea level rise that threatens coastal communities and infrastructure, saltwater contamination of drinking water and the destruction of coastal wetlands; increased incidence of storm surges and flooding of low-lying coastal areas which would lead to the erosion of beaches; and

WHEREAS, a carbon constraint on fossil fuel-fired electricity generation and the development of a CO_2 allowance trading mechanism will create a strong incentive for the creation, development, and deployment of more efficient fuel burning technologies and processes, as well as renewable energy supplies, demand-side management practices and actions to increase energy efficiency, and will lead to less dependence on the import of fossil fuels; and

WHEREAS, reducing our dependence on imported fossil fuels will enhance the region's economy by augmenting the region's energy security and by retaining energy spending and investments in the region; and

WHEREAS, the Signatory States wish to establish themselves and their industries as world leaders in the creation, development, and deployment of carbon emission control technologies, renewable energy supplies, and energy-efficient technologies, demand-side management practices, and increase the share of energy used within the Signatory States that is derived from secure and reliable supplies of energy; and

WHEREAS, climate change is occurring now, and continued delay in taking action to address the emissions that cause climate change will make any later necessary investments in mitigation and adaptive infrastructure much more difficult and costly; and

WHEREAS, to address global climate change and in order to do their fair share in addressing their contribution to this collective problem while preserving and enhancing the economic welfare of their residents, the Signatory States find it imperative to act together to control emissions of greenhouse gases, particularly carbon dioxide, into the Earth's atmosphere from within their region.

NOW THEREFORE, the Signatory States express their mutual understandings and commitments as follows:

1. OVERALL ENVIRONMENTAL GOAL

The Signatory States commit to propose for legislative and/or regulatory approval a CO_2 Budget Trading Program (the "Program") aimed at stabilizing and then reducing CO_2 emissions within the Signatory States, and implementing a regional CO_2 emissions budget and allowance trading program that will regulate CO_2 emissions from fossil fuel-fired electricity generating units having a rated capacity equal to or greater than 25 megawatts.

2. CO_2 BUDGET TRADING PROGRAM

A. Program Adoption. Each of the Signatory States commits to propose, for legislative and/or regulatory approval, the Program substantially as reflected in a Model Rule that will reflect the understandings and commitments of the states contained herein. The Program launch date will be January 1, 2009 as provided in 3.C. below.

B. Regional Emissions Cap. The regional base annual CO_2 emissions budget will be equal to 121,253,550 short tons.

C. State Emissions Caps. The regional base annual CO_2 emissions budget will be apportioned to the States so that each state's initial base annual CO_2 emissions budget is as follows:

Connecticut:	10,695,036 short tons
Delaware:	7,559,787 short tons
Maine:	5,948,902 short tons
New Hampshire:	8,620,460 short tons
New Jersey:	22,892,730 short tons
New York:	64,310,805 short tons
Vermont:	1,225,830 short tons

For the years 2009 through 2014, each state's base annual CO_2 emissions budget shall remain unchanged.

D. Scheduled Reductions. Beginning with the annual allocations for the year 2015, each state's base annual CO_2 emissions budget will decline by 2.5% per year so that each state's base annual emissions budget for 2018 will be 10% below its initial base annual CO_2 emissions budget.

E. Compliance Period and Safety Valve.

(1) Compliance Period. The compliance period shall be a minimum of three (3) years, unless extended after a Safety Valve Trigger Event (described below). A subject facility must have a sufficient number of allowances at the end of each compliance period to cover its emissions during that period.

(2) Safety Valve Trigger.

(a) Safety Valve Trigger. If, after the Market Settling Period (as defined below), the average regional spot price for CO_2 allowances equals or exceeds the Safety Valve Threshold (defined below) for a period of twelve months on a rolling average (a "Safety Valve Trigger Event"), then the compliance period may be extended by up to 3 one-year periods.

(b) Safety Valve Threshold. The Safety Valve Threshold shall be equal to $10.00 (2005$), as adjusted by the Consumer Price Index (CPI) plus 2% per year beginning January 1, 2006.

(c) Market Settling Period. The Market Settling Period is the first 14 months of each compliance period.

F. Offsets. The Program will provide for the award of offset allowances to sponsors of approved CO_2 (or CO_2 equivalent) emissions offset projects for reductions that are realized on or after the date of this MOU. Offset allowances may be used for compliance by units subject to the Program. Among the key features of the offset component of the Program are:

(1) General Requirements.

(a) Minimum Eligibility Requirements. At a minimum, eligible offsets shall consist of actions that are real, surplus, verifiable, permanent and enforceable.

(b) Initial Offset Types. The initial offset project types that may be approved by a Signatory State are: landfill gas (methane) capture and combustion; sulfur hexafluoride (SF_6) capture and recycling; afforestation (transition of land from non-forested to forested state); end-use efficiency for natural gas, propane and heating oil; methane capture from farming operations; and projects to reduce fugitive methane emissions from natural gas transmission and distribution. The measurement and verification protocols and certification processes will be consistent across the Signatory States and incorporated into each State's program.

(c) Additional Offset Types. The Signatory States agree to continue to cooperate on the development of additional offset categories and types, including other types of forestry projects, and grassland re-vegetation projects. Additional offset types will be added to the Program upon approval of the Signatory States.

(2) Initial Offsets Geography and Limits.

(a) Geographic Location of Offset Projects. Offset allowances may be awarded to projects located anywhere inside the United States, provided:

(1) allowances for projects located inside a Signatory State shall be awarded on the basis of one allowance for each CO_2-equivalent ton of certified reduction; and

(2) allowances for projects located outside the Signatory States shall be awarded one allowance for every two CO_2-equivalent tons of certified reduction.

(b) Limit on Offsets Use. In each compliance period, a source may cover up to 3.3% of its reported emissions with offset allowances.

(3) Offsets Trigger and Reset.

(a) Offsets Trigger. If, after the Market Settling Period (defined above), the average regional spot price for CO_2 allowances equals or exceeds $7.00 (2005$) per ton for a period of twelve months on a rolling average (an "Offsets Trigger Event"), then:

(1) offset allowances may be awarded to projects located anywhere in North America; and

(2) offset allowances will be awarded on the basis of one allowance for each CO_2-equivalent ton of certified reduction; and

(3) the percentage of offsets that a source may use to cover its emissions shall increase to 5.0% of its reported emissions for the compliance period in which the Offsets Trigger Event occurs.

(b) Offsets Reset. After an Offset Trigger Event, the limits on geography and use of offsets set forth in Section F.2. shall once again apply commencing at the start of the subsequent compliance period.

(4) Safety Valve Offsets Trigger and Reset.

(a) Safety Valve Offsets Trigger. If a Safety Valve Trigger Event has occurred twice in two consecutive 12-month periods (a "Safety Valve Offsets Trigger Event"), then:

(1) offset allowances may be awarded to projects located anywhere in North America or from international trading programs; and

(2) offset allowances may be awarded to projects located anywhere in North America or credits from international trading programs shall be awarded on the basis of one allowance for each CO_2-equivalent ton of certified reduction; and

(3) the percentage of offsets that a source may use to cover its emissions shall increase to 5.0% of its reported emissions for the first three years of the compliance period and 20% of its reported emissions for the period beginning with the fourth year of the compliance period and continuing through the end of the compliance period.

(b) Safety Valve Offsets Reset. After a Safety Valve Offsets Trigger Event, the limits on geography and use of offsets set forth in Section F.2. shall once again apply commencing at the start of the subsequent compliance period.

G. Allocations of Allowances. Each Signatory State may allocate allowances from its CO_2 emissions budget as determined appropriate by each Signatory State, provided:

(1) each Signatory State agrees that 25% of the allowances will be allocated for a consumer benefit or strategic energy purpose. Consumer benefit or strategic energy purposes include the use of the allowances to promote energy efficiency, to directly mitigate electricity ratepayer impacts, to promote renewable or non-carbon-emitting energy technologies, to stimulate or reward investment in the development of innovative carbon emissions abatement technologies with significant carbon reduction potential, and/or to fund administration of this Program; and

(2) the Signatory States recognize that, in order to provide regulatory certainty to covered sources, state-specific rules for allocations should be completed as far in advance of the launch of the Program as practicable.

H. Early Reduction Credits. Each Signatory State may grant early reduction credits for projects undertaken after the date this Memorandum is signed and prior to the launch of the Program as defined in 3.C. at facilities subject to the Program, which projects have the effect of reducing emissions from the facility by (a) an absolute reduction of emissions through emission rate improvements; or (b) permanently reducing utilization of one or more units at the facility.

I. Banking. The banking of allowances, offset allowances and early reduction credits will be allowed without limitation.

3. MODEL RULE FOR ESTABLISHMENT OF THE CO_2 BUDGET TRADING PROGRAM

A. Model Rule. The Signatory States are collectively developing a draft Model Rule to serve as the framework for the creation of necessary statutory and/or regulatory authority to establish the Program. The Signatory States will use their best efforts to collectively release this draft Model Rule within 90 days after the execution of this MOU for a 60-day public review and comment period. Comments received during this comment period shall be reviewed by the Signatory States, and revisions to the draft Model Rule will be considered. A revised Model Rule will be developed and released within 45 days of the close of the public comment period after consultation among the Signatory States.

B. Legislation and/or Rulemaking. Each Signatory State commits to seek to establish in statute and/or regulation the Program and have that State's component of the regional Program effective as soon as practicable but no later than December 31, 2008.

C. Launch of Program. The Signatory States intend that the first compliance period of the Program will commence January 1, 2009.

4. REGIONAL ORGANIZATION

In order to facilitate the ongoing administration of the Program, the Signatory States agree to create and maintain a regional organization ("RO") with a primary office in New York City. The RO will be a non-profit entity incorporated in New York and will operate pursuant to by-laws agreed upon by the Signatory States. The RO shall have an Executive Board comprised of two representatives from each Signatory State. The RO may employ staff and acquire and dispose of assets in order to perform its functions.

A. RO Functions. The RO will have the following functions:

(1) Deliberative Forum. Act as the forum for collective deliberation and action among the Signatory States in implementing the Program. The by-laws of the RO shall specify the process for deliberation and arriving at agreement to take collective action.

(2) Emissions and Allowance Tracking. Act on behalf of each of the Signatory States in developing, implementing and maintaining the system to receive and store reported emissions data from sources and track allowance accounts for the Program.

(3) Offsets Development. Provide technical support to the States for the development of new offset standards to be added to state rules.

(4) Offsets Implementation. Provide technical assistance to the States in reviewing and assessing applications for offsets projects. Such technical assistance may include the development of model guidance documents for use by the States for potential sponsors of offset projects. At the

request of any Signatory State, the RO may assist in the review of any application for the award of offsets credits.

(5) Limitation on Powers. The RO is a technical assistance organization only. The RO shall have no regulatory or enforcement authority with respect to the Program, and such authority is reserved to each Signatory State for the implementation of its rule.

B. Funding for the RO. The Signatory States agree that the RO shall be funded at least in part through payments from each Signatory State in proportion to the State's annual base CO2 Emissions Budget. The RO's budget shall be determined and approved by the RO's Executive Board.

5. ADDITION OR REMOVAL OF SIGNATORY STATES

A. New Signatory States.

(1) New Signatories. A Non-Signatory State may become a Signatory State by agreement of the Signatory States as reflected in an amendment to this MOU.

(2) Expansion. The Signatory States shall work together to encourage Non-Signatory States to become Signatory States and shall welcome expressions of interest from Non-Signatory States with a goal to expand the geographic reach of the Program.

(3) Massachusetts and Rhode Island. The Signatory States recognize the contributions of Massachusetts and Rhode Island to the design and development of the Program and the negotiation of this MOU. The Signatory States agree that Massachusetts and Rhode Island may become signatories to this MOU at any time prior to January 1, 2008, without any amendment to the terms of this MOU. In the event that authorized representatives of Massachusetts and/or Rhode Island execute this MOU before such date, they shall receive the following CO_2 emissions budgets:

Massachusetts:	26,660,204 short tons
Rhode Island:	2,659,239 short tons

In the event that Massachusetts and/or Rhode Island become Signatory States under this paragraph, then the regional emissions budget set forth in Section 2.B. of this MOU shall be increased to include the allowance budgets of Massachusetts and/or Rhode Island.

B. Withdrawal of a Signatory State. A Signatory State may, upon 30 days written notice, withdraw its agreement to this MOU and become a Non-Signatory State. In this event, the remaining Signatory States would execute measures to appropriately adjust allowance usage to account for the corresponding subtraction of units from the Program.

C. Removal of Signatory State. Removal of a Signatory State shall be handled in the by-laws of the Regional Organization.

6. PROGRAM MONITORING AND REVIEW

The Signatory States agree to monitor the progress of the Program on an ongoing basis.

A. Imports and Associated Emissions Leakage. The Signatory States recognize the potential that the Program may lead to increased electricity imports and associated emissions leakage. To address this potential, the Signatory States:

(1) agree to promptly, but no later than April 1, 2006, establish a multi-state working group consisting of representatives from the energy regulatory and environmental agencies in the Signatory States. The multi-state working group shall:

(a) consider potential options for addressing leakage. Attention shall be paid not only to the potential effectiveness of a particular option to address leakage, but also to the potential impacts that option may have on energy prices, allowance prices, electric system reliability and on the economies of the RGGI states. In considering potential options, the working group shall consult with a panel of experts, stakeholders and representatives of the regional transmission organizations.

(b) issue its findings and conclusions by December 2007.

(2) agree to consider, after taking into account the analyses and findings called for under Section 6(a)(1), what actions should be taken to address potential leakage prior to the launch of the program in January 2009.

(3) monitor electricity imports into the Signatory States on an ongoing basis commencing from the start of the program, and report the results of the monitoring on an annual basis beginning in 2010.

(4) immediately following the first three-year compliance period and at any time thereafter, determine whether and to what extent any increase in emissions

from electric generating units outside the Signatory States is attributable to the Program.

(5) if at any point after the launch of the program there is a determination that the Program has led to a significant increase in emissions from electric generating units outside the Signatory States, the Signatory States shall, after taking into account the analyses and findings called for under Section 6(a)(1), implement appropriate measures to mitigate such emissions.

(6) The Signatory States agree to pursue technically sound measures to prevent leakage from undermining the integrity of the Program.

B. Monitoring of Reliability Impacts. The Signatory States recognize the paramount importance of maintaining a reliable electrical system in the region, and are committed to monitoring the Program on an ongoing basis to ensure that the Program will not result in electricity supply interruptions.

C. Federal Program. When a federal program is proposed, the Signatory States will advocate for a federal program that rewards states that are first movers. If such a federal program is adopted, and it is determined to be comparable to this Program, the Signatory States will transition into the federal program.

D. Comprehensive 2012 Review. In 2012, the Signatory States will commence a comprehensive review of all components of the Program, including but not limited to:

(1) Program Success. The Signatory States will review whether the Program has been successful in meeting its goals.

(2) Program Impacts. The Signatory States will review the impacts of the Program as to price and system reliability.

(3) Additional Reductions. The Signatory States will consider whether additional reductions after 2018 should be implemented.

(4) Imports and Emissions Leakage. The Signatory States will consider the effectiveness of any measures put in place to control emissions leakage.

(5) Offsets. The Signatory States will evaluate the offsets component of the Program, with attention to price, availability, and environmental integrity, and recommend whether changes to the Program are warranted.

7. COMPLEMENTARY ENERGY POLICIES

Each state will maintain and, where feasible, expand energy policies to decrease the use of less efficient or relatively higher polluting generation while maintaining economic growth. These may include such measures as: end-use efficiency programs, demand response programs, distributed generation policies, electricity rate designs, appliance efficiency standards and building codes. Also, each state will maintain and, where feasible, expand programs that encourage development of non-carbon emitting electric generation and related technologies.

8. AMENDMENT

This MOU may be amended in writing upon the collective agreement of the authorized representatives of the Signatory States.

[Signatures on Next Page]

This Memorandum of Understanding on the Regional Greenhouse Gas Initiative signed as of the 20th day of December, 2005.

THE STATE OF CONNECTICUT

By: ______________________

M. Jodi Rell
Governor

This Memorandum of Understanding on the Regional Greenhouse Gas Initiative signed as of the 20th day of December, 2005.

THE STATE OF DELAWARE

By: Ruth Ann Minner

Ruth Ann Minner
Governor

This Memorandum of Understanding on the Regional Greenhouse Gas Initiative signed as of the 30th day of December, 2005.

THE STATE OF MAINE

By: ______________________

John Elias Baldacci
Governor

This Memorandum of Understanding on the Regional Greenhouse Gas Initiative signed as of the 20th day of December, 2005.

STATE OF NEW HAMPSHIRE

By: ____________________

John Lynch
Governor

This Memorandum of Understanding on the Regional Greenhouse Gas Initiative signed as of the 20th day of December, 2005.

STATE OF NEW JERSEY

By: Richard J. Codey

Richard Codey
Governor

This Memorandum of Understanding on the Regional Greenhouse Gas Initiative signed as of the 20th day of December, 2005.

STATE OF NEW YORK

By: ______________________

George E. Pataki
Governor

This Memorandum of Understanding on the Regional Greenhouse Gas Initiative signed as of the 20th day of December, 2005.

STATE OF VERMONT

By: ______________________

James Douglas
Governor

This Memorandum of Understanding on the Regional Greenhouse Gas Initiative signed as of the _______ day of ____________________, 20____.

COMMONWEALTH OF MASSACHUSETTS

By:________________________________
Its:

This Memorandum of Understanding on the Regional Greenhouse Gas Initiative signed as of the _______ day of ____________________, 20____.

STATE OF RHODE ISLAND &
PROVIDENCE PLANTATIONS

By:________________________
Its:

EXHIBIT 5

Western Climate Initiative

www.westernclimateinitiative.org

Western Climate Initiative

Statement of Regional Goal

August 22, 2007

1. Regional Goals. The Western Climate Initiative (WCI) regional greenhouse gas emission reduction goal is an aggregate reduction of 15% below 2005 levels by 2020.

- This regional, economy-wide goal is consistent with the emission goals of WCI partners and does not replace the partners' existing goals.
- The WCI partners acknowledge that new entrants and updates to data may result in some incremental changes to the regional goal.
- The metrics for establishing this goal are documented in Attachment A.

The WCI partners commit to do their share to reduce regional GHG emissions sufficient over the long term to significantly lower the risk of dangerous threats to the climate. Current science suggests that this will require worldwide reductions between 50% and 85% in carbon dioxide emissions from current levels by 2050.[1]

2. New Entrants. The WCI encourages participation by additional US states, tribes, Canadian provinces, and Mexican states that are making comparable efforts to combat climate change. In determining whether the new entrant is undertaking comparable efforts to meet the challenge of climate change, the partners shall consider whether the proposed new entrant:

a. Has adopted an economy-wide greenhouse gas reduction goal. The goal shall reflect a level of effort that is consistent with that of the WCI partners;

[1] IPCC Fourth Assessment Report, Working Group III, Mitigation of Climate Change

b. Has developed or is developing a comprehensive multi-sector climate action plan to achieve the goal;

c. Has committed to adopt greenhouse gas tailpipe standards for passenger vehicles; and

d. Is participating in The Climate Registry.

When deciding whether to accept a new entrant, the partners may consider other factors they deem appropriate. The partners will establish a decision-making process on adopting new entrants.

3. Coverage of Actions in the Goal. Emissions reduction activities by which partners achieve the regional reduction goal should be comprehensive and economy-wide, including:

a. Regional multi-sector market-based mechanisms;

b. Actions in all sectors, including but not limited to: stationary sources, energy supply, residential, commercial, industrial, transportation, waste management, agriculture, and forestry; and

c. Reduction in emission of any GHG reported to the UN Framework Convention on Climate Change by the USEPA and Environment Canada, i.e., carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

4. Reporting Requirements. Each partner will update the other WCI partners on their climate action plan and GHG emissions inventories every two years to ensure that actions are underway at levels consistent with full achievement of the 2020 goal.

Attachment A: Metrics used to Establish WCI Regional Goal

The WCI aggregate greenhouse gas emission reduction goal of 15% below 2005 levels by 2020 is based on:

- The aggregation of GHG emissions and emissions goals of WCI partners that have thus far established a 2020 goal (Arizona, British Columbia, California, New Mexico, Oregon, and Washington) and Manitoba's short-term goal, as shown in the Table 1 below.

- Currently available state or provincial emissions inventories. Some of these inventories are currently under revision, and the values shown in Table 2 below will be periodically updated. While further changes to specific emissions estimates are likely, the aggregate regional emission reduction goal for the current partners is unlikely to deviate substantially from 15% below 2005 levels by 2020.

- Gross emissions estimates, across all sectors, for the six greenhouse gases reported to the UN Framework Convention on Climate Change by the USEPA in the U.S. Greenhouse Gas Inventory and by Environment Canada in the Canada National Inventory Report: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). These estimates are presented in terms of CO_2 equivalence (CO_2e), which indicates the relative contribution of each gas to global average radiative forcing on a 100-year Global Warming Potential (GWP) weighted basis. Gross emissions estimates do not include changes in biological carbon stocks due to agriculture, forestry, and land use change. In addition, GHG emissions associated with international aviation and international bunker fuels are generally excluded.

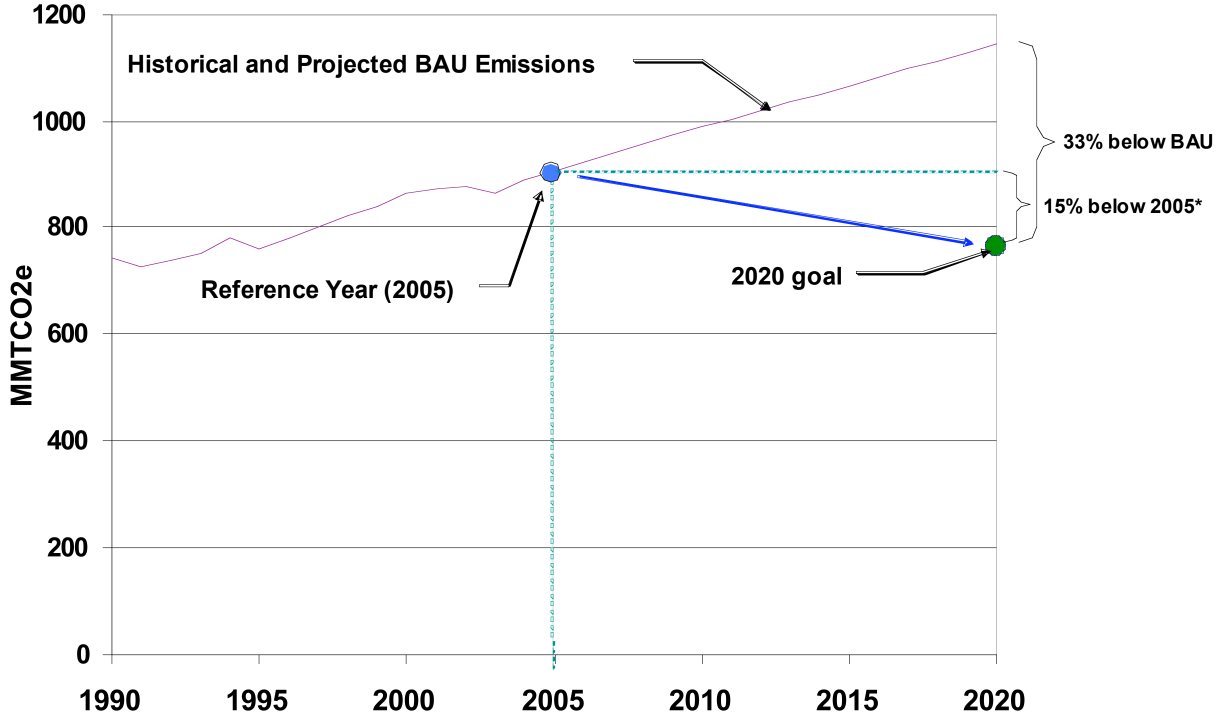
- Consumption-based (or "load-based") emissions estimates for the electricity sector, except where such estimates are currently unavailable, in which case production-based estimates are used (British Columbia). Consumption-based estimates reflect the emissions associated with generating the electricity delivered to consumers in each state or province whether the electricity was generated in state/province or out of state/province. Considerable work is currently underway to further develop and improve consumption-based estimates.

Table 1. State and Provincial Goals for GHG Reductions

	Short Term (2010-12)	Medium Term (2020)	Long Term (2040-50)
Arizona	not established	2000 levels by 2020	50% below 2000 by 2040
British Columbia	not established	33% below 2007 by 2020	not established
California	2000 levels by 2010	1990 levels by 2020	80% below 1990 by 2050
Manitoba	6% below 1990	6% below 1990[2]	not established
New Mexico	2000 levels by 2012	10% below 2000 by 2020	75% below 2000 by 2050
Oregon	arrest emissions growth	10% below 1990 by 2020	>75% below 1990 by 2050
Utah	Will set goals by June 2008		
Washington	not established	1990 levels by 2020	50% below 1990 by 2050

[2] Manitoba has not yet established a formal goal for 2020, but expects to meet or do better than its short term goal.

WCI Partner GHG Emissions and Regional Goal[3]



BAU = Business-as-usual (projections).

The arrow shown is purely directional: it illustrates the where regional emissions will need to be by 2020 rather than the specific path emissions are expected to follow during the 2007-2020 period.

* See footnote c in the Table 2 below.

[3] Note that this chart does not include Manitoba emissions, which will be added when 2020 projections are available.

Table 2 compiles and compares WCI partner goals for the year 2020, and indicates the relative percentage emissions reduction below historical (1990, 2000, and 2005) or projected (business-as-usual or "BAU" in 2020) levels that these goals imply. Also shown are the absolute emission reductions below projected BAU levels in 2020 in million metric tons of CO2 equivalents (MMtCO2e) that are needed to meet these goals. The final column indicates how fast greenhouse gas emissions would be expected to grow from 1990 to 2020 were no action taken to reduce them. The final row shows the aggregate result for the WCI partners that have established 2020 goals (percents are based on total emissions for the partners shown). As illustrated, the compilation of partner goals represents an aggregate 16% reduction below 2005 levels by 2020. This figure has been rounded to 15% for the regional goal, as stated above.

Table 2. Summary Compilation and Comparison of 2020 goals (Estimates as of July 2007[a])

	Goals					1990-2020 BAU growth
	Relative to 1990	**Relative to 2000**	**Relative to 2005**	**Relative to 2020 BAU[b]**	**Absolute Reductions from BAU (MMtCO2e)**	
Arizona	35%	0%	-11%	-45%	72	144%
British Columbia	-9%	-27%	-30%	-46%	40	69%
California	0%	-10%	-14%	-28%	170	40%
Manitoba	-6%	-16%	-17%	TBD	TBD	TBD
New Mexico	14%	-10%	-14%	-31%	28	65%
Oregon	-10%	-29%	-32%	-44%	40	61%
Washington	0%	-16%	-11%	-28%	33	40%
Total	**2%**	**-12%**	**-16%[c]**	**-33%[d]**	**383[d]**	**54%[d]**

[a] Methodologies for estimating electricity emissions may not be fully comparable. State electricity emissions estimates used to develop the figures shown above are consumption-based (i.e. "load-based"); methodologies for consumption-based electricity emissions vary among states. Provincial electricity emission estimates are currently available only on a production basis.

[b] Current BAU forecasts (2020 estimates) may not be fully comparable. Two factors, in particular, may need to be further examined with respect to assessing comparability of effort: a) underlying socioeconomic projections, most notably population and economic activity; and, b) the extent to which emission reduction actions are included in BAU projections.

[c] The WCI goal of 15% below 2005 levels reflects a rounding of this figure, which may change slightly as partner states and provinces continue to refine their GHG inventories.

[d] These totals do not include Manitoba emissions, since projections are not currently available.

References for GHG emissions estimates:

Arizona: "Climate Change Action Plan", Arizona Climate Change Advisory Group, August 2006. http://www.azclimatechange.gov/

British Columbia: Historical emissions from Environment Canada, "National Inventory Report: 1990 - 2005", http://www.ec.gc.ca/pdb/ghg/inventory_report/2005_report/toc_e.cfm; projections from BC Ministry of Environment calculations based on Natural Resources Canada and Simon Fraser University estimates.

California: "Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2004", Staff Final Report, December 2006, CEC-600-2006-013-SF, http://www.climatechange.ca.gov/policies/greenhouse_gas_inventory/index.html

Manitoba: Historical emissions from Environment Canada, "National Inventory Report: 1990 - 2005", http://www.ec.gc.ca/pdb/ghg/inventory_report/2005_report/toc_e.cfm

New Mexico: "Final Report", New Mexico Climate Change Advisory Group, December 2006, http://www.nmclimatechange.us

Oregon: "Oregon Strategy for Greenhouse Gas Reductions", Governor's Advisory Group on Global Warming, December 2004, http://www.oregon.gov/ENERGY/GBLWRM/Strategy.shtml, with subsequent revisions yet to be published.

Washington: "Greenhouse Gas Inventory and Reference Case Projections", Washington State Climate Advisory Team, April 2007 Draft, with subsequent revisions yet to be published. http://www.ecy.wa.gov/climatechange/cat_documents.htm

References for GHG emissions goals:

Arizona: "Climate Change Action" Governor Janet Napolitano's Executive Order 2006-13, September 8, 2006 http://www.governor.state.az.us/dms/upload/EO_2006-13_090806.pdf

British Columbia: "Speech from the Throne" February 13, 2007 http://www.leg.bc.ca/38th3rd/4-8-38-3.htm

California: Governor Arnold Schwarzenegger's Executive Order S-3-05 and AB32 legislation, http://www.climatechange.ca.gov/

Manitoba: "Kyoto and Beyond", Province of Manitoba Climate Change Action Plan, 2002, http://www.gov.mb.ca/est/climatechange/pdfs/final-mccap-sep-16-02.pdf

New Mexico: "Climate Change and Greenhouse Gas Reduction",.Governor Bill Richardson's Executive Order 2005-033, June 9, 2005, http://www.governor.state.nm.us/2005orders.php

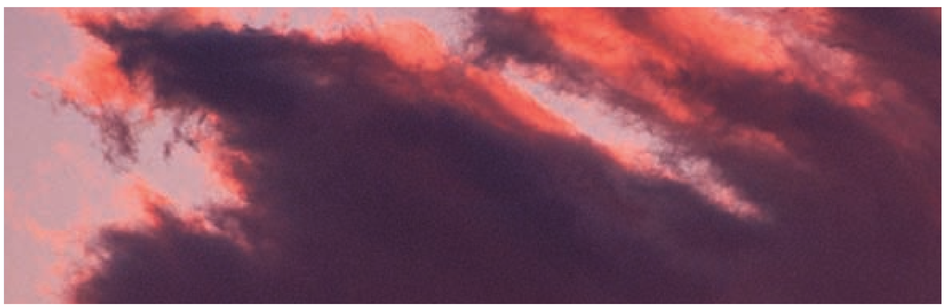
Oregon: Enrolled House Bill 3543, signed into law on August 7, 2007 by Governor Ted Kulongoski, http://www.leg.state.or.us/07reg/measpdf/hb3500.dir/hb3543.en.pdf

Washington: Governor Christine Gregoire's Executive Order 07-02, February 7, 2007, http://www.governor.wa.gov/execorders/eo_07-02.pdf and Engrossed Substitute Senate Bill (ESSB) 6001, http://www.leg.wa.gov/pub/billinfo/2007-08/Pdf/Bill%20Reports/Senate%20Final/6001-S.FBR.pdf

EXHIBIT 6

MIDWESTERN GREENHOUSE GAS ACCORD

2007



MIDWESTERN ENERGY SECURITY & CLIMATE STEWARDSHIP SUMMIT

MGA
Midwestern Governors Association

MIDWESTERN GREENHOUSE GAS REDUCTION ACCORD

WHEREAS, the effects of climate change present growing economic, social and environmental risks in the Midwest and the world; and

WHEREAS, we know enough to act on climate change, and there is sufficient scientific certainty that we must begin to take action now; and

WHEREAS, government has the obligation to establish a policy framework for reducing emissions of the six recognized greenhouse gases (GHG) while maintaining reliability and enhancing the cost-competitiveness of the Midwest's energy supply; and

WHEREAS, regional cooperation will help the Midwest respond to and prosper in a carbon-constrained world and maximize the region's comparative energy advantages, including:

1. national leadership by individual Midwestern states and provinces in the delivery of effective energy efficiency programs; and

2. world-class renewable energy resources that support rapidly growing wind energy, corn ethanol and biodiesel industries, as well as the potential for robust cellulosic biomass and solar industries; and

3. extensive and secure coal reserves, combined with extensive geologic reservoirs for storing carbon dioxide (CO_2); and

4. pioneering experience with the capture of CO_2 for use in enhanced oil and gas recovery (EOR) to extend production from the region's oil and gas fields, including the world's largest CO_2 storage project that presently captures 3 million tons of CO_2 annually from coal in North Dakota and transports it by pipeline to Saskatchewan for EOR; and

5. national leadership by the Midwest's agricultural and forestry communities to implement both methane mitigation and terrestrial carbon sequestration programs and practices; and

WHEREAS, addressing climate change will create new economic opportunities and produce economic growth and jobs by maximizing the region's low-carbon energy production and by providing opportunities for the Midwest's manufacturing and service sectors to supply low-carbon technologies and know-how to the region and the world; and

WHEREAS, meeting governments' obligations on climate change will require a range of strategies, including incentives, flexible market-based approaches and legal requirements; and

WHEREAS, a multi-jurisdictional GHG registry (The Climate Registry) is under development and is expected to be operational in early 2008 and will be available for entities participating in this program; and

WHEREAS, the Chicago Climate Exchange, sulfur dioxide trading markets and other established market-based systems in the U.S.; the Montreal Protocol for protecting the ozone layer; and the European Union's Emission Trading Scheme for GHG emissions allowances all provide working examples of emissions reduction mechanisms; and

WHEREAS, the Midwest can draw on the most effective aspects of other jurisdictions' experiences in crafting a coordinated, regional approach to the climate challenge that takes advantage of the Midwest's strengths and is environmentally effective, fair and cost efficient; and

WHEREAS, the U.S. federal government has not met the challenge to date of crafting a comprehensive national response to climate change, while governors representing U.S. states and national governments around the world have made commitments to reduce GHG emissions; and

WHEREAS, some Midwestern governments have established significant CO_2 reduction targets, either by executive order or statute, and formed climate task forces to advise on policies and strategies for meeting such targets; and

WHEREAS, we recognize the benefits of regional collaboration in developing climate change policies and approaches to GHG reductions that provide for consistency across jurisdictions;

NOW, THEREFORE, BE IT:

RESOLVED, that we, the undersigned, jointly enter into this accord to establish a Midwestern Greenhouse Gas Reduction Program (hereafter Program) to reduce GHG emissions in our states, and we jointly endeavor to:

1. establish GHG reduction targets and timeframes consistent with MGA member states' in provincial targets; and

2. develop a market-based and multi-sector cap-and-trade mechanism to help achieve GHG reduction targets; and

3. join The Climate Registry to enable tracking, management and crediting for entities that reduce GHG emissions; and

4. develop and implement other associated mechanisms and policies as needed to achieve the GHG reduction targets, such as a low-carbon fuel standard and regional incentives and funding mechanisms; and be it

RESOLVED, that the above described cap-and-trade system be developed to:

1. enable linkage to other jurisdictions' systems to create economies of scale, increase market efficiencies, diversity and liquidity, while reducing costs; and

2. maximize economic and employment benefits, while minimizing any transitional job losses; and

3. reduce the shifting of generation and emissions to non-participating states; and

4. credit past and present actions to reduce GHG emissions; and

5. address potential interaction or integration with a future federal program; and be it

RESOLVED, MGA member and other states, Canadian provinces, tribal governments and First Nations, and other jurisdictions may participate in the program, or they may choose to observe; and be it

RESOLVED, that we agree to establish a Work Group structure and process, through the Midwestern Governors Association, involving representatives of public, private and nongovernmental institutions to make recommendations to governors and other participating jurisdictional leaders regarding implementation; and be it

RESOLVED, that we shall:

1. direct our staff and appropriate state agency representatives to develop a work plan and establish a work group to move forward with the Program, within two months of the effective date of this accord; and

2. establish targets for GHG emission reductions and timeframes consistent with states' targets, and adopt policies, implementation mechanisms and any work products deemed necessary, within eight months of the effective date of this accord; and

3. complete development of proposed cap-and-trade agreement and a model rule, within 12 months of the effective date of this accord; and

4. complete the undertakings set forth herein, within 30 months of the effective date of this accord.

DONE, this 15th day of November, 2007, in Milwaukee, Wisconsin.

EXHIBIT 7

K A N S A S

RODERICK L. BREMBY, SECRETARY

KATHLEEN SEBELIUS, GOVERNOR

DEPARTMENT OF HEALTH AND ENVIRONMENT

October 18, 2007

Sunflower Electric Power Corporation
Mr. Wayne Penrod
Senior Manager
301 W. 13th
Hays, KS 67601

Dear Mr. Penrod:

It is my duty as Secretary of the Kansas Department of Health and Environment, as authorized by the Kansas air quality act, K.S.A. 65-3001 et seq. to protect the public health and environment from actual, threatened or potential harm from air pollution.

The secretary has broad authority under the act and the regulations adopted thereunder to achieve protection of the health of the people and the environment. . The secretary has authority under K.S.A. 65-3008a(b) to affirm, modify or reverse a decision on an air quality permit after the public comment period or public hearing. The secretary also has authority under K.S.A. 65-3012 as interpreted by the Attorney General of the state of Kansas, to take such action as is necessary to protect the health of persons or the environment, notwithstanding a permit applicant's compliance with all other existing provisions of the Kansas air quality act, upon receipt of information that the emission of air pollution presents a substantial endangerment to the health of person or the environment. The endangerment may be a threatened or potential harm as well as an actual harm.

The Supreme Court of the United States found in Massachusetts v. E.P.A., 127 S.Ct. 1438 (April 2, 2007) that carbon dioxide, a greenhouse gas, meets the broad definition of air pollutant under the Clean Air Act. The Kansas air quality act similarly has a broad definition of what constitutes air pollution. The Court also recognized the significant existing national and international information available on the deleterious impact of greenhouse gases on the environment in which we live.

I have given due consideration to the scientific and technical information related to carbon dioxide including but not limited to many oral and written comments submitted in the public hearing and comment period. The information provides support for the position that emission of air pollution from the proposed coal fired plant, specifically carbon dioxide emissions, presents a substantial endangerment to the health of persons or to the environment.

Based on this information, the permit is denied. Pursuant to K.S.A. 65-3008b(e),the permit applicant has the right to appeal this decision within fifteen (15) days and request an administrative hearing under the Kansas administrative procedures act set forth at K.S.A. 77-501 *et seq.*

Sincerely,

Roderick L. Bremby
Secretary