II. Energy

Section II presents international emissions baselines and marginal abatement curves (MACs) for energy sources. There are three chapters, each addressing an individual source from the coal mining, natural gas, and oil sectors. These sources are associated with methane (CH_4) emissions. MAC data are presented in both percentage reduction and absolute reduction terms relative to the baseline emissions. These data can be downloaded in spreadsheet format from the USEPA's Web site at
<http://www.epa.gov/nonco2/econ-inv/international.html>.

Section II—Energy chapters are organized as follows:

Methane (CH_4)

II.1 Coal Mining Sector

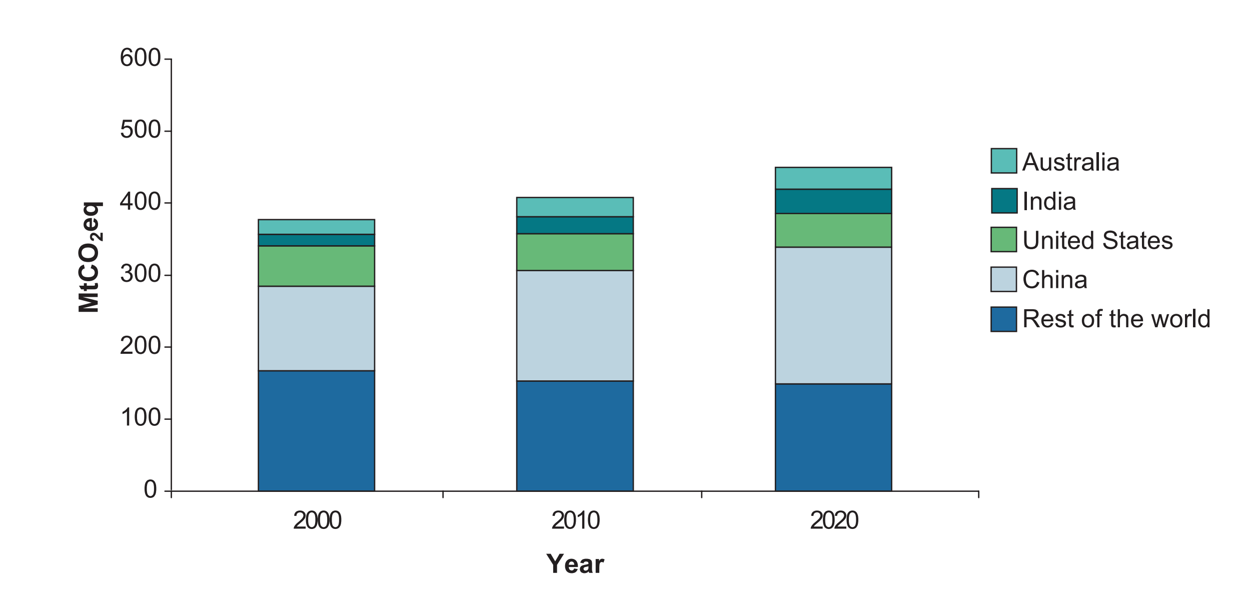
II.2 Natural Gas Sector

II.3 Oil Sector

II.1 Coal Mining Sector

Worldwide, the coal mining industry liberated more than 377 million metric tons of carbon dioxide equivalent ($MtCO_2eq$), which accounted for 3.3 percent of total anthropogenic methane (CH_4) emissions in 2000. China, the United States, India, and Australia account for more than 56 percent of coal mining CH_4 emissions (Figure 1-1). Emissions are projected to grow 20 percent from 2000 to 2020, with China increasing its share of worldwide emissions from 31 percent to 42 percent.

Figure 1-1: CH_4 Emissions from Coal Mining, by Country: 2000–2020



Source: U.S. Environmental Protection Agency (USEPA), 2006.

II.1.1 Introduction

CH_4 is produced during the process of converting organic matter to coal. The CH_4 is stored in pockets within a coal seam until it is released during coal mining operations. The largest source of emissions occurs during mining. Although, some emissions occur during the processing, transport, and storage of coal. Many factors affect the quantity of CH_4 released, including the gas content of the coal, the permeability and porosity of the coal seams, the method of mining used, and the production capacity of the mining operation. The depth of a coal seam and the type of coal determine the amount of CH_4 present (or the gas content) in and around the coal seams. Deep coal seams generally have large amounts of CH_4 because of greater overburden pressures. As a result, more than 90 percent of fugitive CH_4 emissions from the coal sector come from underground coal mining.

A high concentration of CH_4 in underground coal mines is a safety hazard; the CH_4 must be extracted before mining operations can be undertaken. To maintain low levels of CH_4 in the mine, degasification is employed prior to mining and ventilation air systems are used during mining operations. Traditionally, CH_4 extracted from the mine is released or vented into the atmosphere. Abatement options have been developed to mitigate these emissions.

The three coal mining abatement options addressed in this chapter are (1) degasification, where holes are drilled and CH_4 is captured (not vented) before mining operations begin (or, in the case of gob gas wells, during and after mining operations); (2) enhanced degasification, where advanced drilling technologies are used and captured low-grade gas is purified; and (3) ventilation air methane (VAM) abatement, where low concentrations of CH_4 ventilation air exhaust flows are oxidized to generate heat for process use and/or electricity generation.

The following discussion offers a brief explanation of how CH_4 is emitted from coal mines, followed by a discussion of international baseline emissions for CH_4 from coal mining and projections for future baseline emissions. Then, we characterize possible abatement technologies, outlining their technical specifications, costs and possible benefits, and potential in selected countries. The final section of this chapter discusses emissions reductions that occur following the implementation of each abatement technology and how these reductions are reflected in the marginal abatement curves (MACs).

II.1.2 Baseline Emissions Estimates

Baseline emissions estimates are calculated by developing activity factors and emissions factors per unit of activity. The activity factor for coal mining's level of coal production and the emissions factor are expressed in terms of the quantity of CH_4 release per ton of coal produced.

CH_4 and coal are created through a combination of biological and geological forces, where plant biomass is converted to coal. CH_4 is stored in natural wells and is also diffused inside the coal itself. CH_4 is contained within the coal seam or strata layer by pressure surrounding the seam. When this pressure drops because of natural erosion, faulting, and underground and surface mining, CH_4 emissions occur. CH_4 emissions vary by type of coal mine and type of mining operation. Abandoned mines are also a source of CH_4 emissions.

Underground Mines. The quantity of CH_4 present in a mine is determined significantly by the coal depth. Geologic pressure increases with depth, trapping more CH_4. Coal from underground mines tends to have a higher carbon content, which is associated with a higher CH_4 content.

Ventilation air systems are used in underground mines to maintain low concentration levels of CH_4 during mining operations. CH_4 is combustible at concentrations between 5 percent and 15 percent. As a safety precaution, countries such as the United States require the use of ventilation systems in mines that have any detectable levels of CH_4. Ventilation systems maintain a CH_4 concentration below 1 percent by using large fans to inject fresh air from the surface into the mine, thereby lowering the in-mine CH_4 concentration. This ventilation air is extracted from the mine and vented to the atmosphere through ventilation shafts or bleeder shafts (see explanatory note 1). The vent air contains very low concentrations of CH_4 (typically below 1 percent).

Degasification systems consist of a network of vertical wells drilled from the surface or boreholes drilled within the mine and gathering systems to pull the CH_4 from the wells to the surface. These wells extract large quantities of CH_4 from the coal seam before and after mining operations. CH_4 extracted by degasification systems has higher concentrations (30 percent to 90 percent) than VAM. Concentrations vary depending on the type of coal mined and the degasification technique used.

*Surface Mine*s Surface mining is a technique used to extract coal from shallow depths below the Earth's surface. Because the geologic pressure at shallow depths is much lower, there is insufficient pressure to contain high concentrations of CH_4, so CH_4 content is generally also much lower (see explanatory note 2). As the overlying surface is removed and the coal exposed, CH_4 is emitted directly into the atmosphere. Surface mines contribute only a small fraction of a country's overall emissions, and surface mining is only applicable in certain geographic regions. For example, in the United States in 2003, surface mining accounted for 67 percent of total domestic coal production. In countries such as China, there is very little surface mining; coal seams are present only at greater depths.

Postmining Operations. The primary source of CH_4 emissions in coal mining is the underground production of coal. However, some emissions occur during processing, storage, and transport of coal. The rate of emissions depends on the type of coal and the way it is handled. The highest rate of emissions occurs when coal is crushed, sized, and dried for industrial and utility uses.

Abandoned Mines. Abandoned mines are another source of CH_4 emissions. Emissions are released through old wells and ventilation shafts. In some cases, the CH_4 from these mines has been captured and used as a source of natural gas or to generate electricity. Currently, these emissions are not included in the baseline estimates.

In summary, the majority of the CH_4 emitted from coal mining comes from gassy underground mines through ventilation and degasification systems. Future emissions levels and the potential for CH_4 recovery and use will be determined by trends in the management of CH_4 gas at such mines.

II.1.2.1 Activity Data

Historical Activity Data

Worldwide coal consumption has increased over time, except in Western Europe, Eastern Europe, and the Former Soviet Union (FSU) (excluding the Russian Federation). Coal consumption decreased 30 percent in Western Europe and 40 percent in Eastern Europe and the FSU from 1990 to 2001. Table 1-1 reports coal mining activity for selected countries during the same period.

In the 1990s, the majority of China's coal mines were operated without modern mining techniques, which usually include cutting equipment, hydraulic pumps, power roof supports, and automated loading devices. In the past decade, in an effort to update their equipment, countries such as China have begun to institute programs to modernize their coal mining operations, allowing them to mine at greater depths. However, several countries experienced decreased demand for coal in the late 1990s, and in response, these countries cut mining production until their surplus supply could be reduced. China dramatically reduced its coal production between 1995 and 2000, and has spent the past 4 years expanding its coal exports to reduce its surplus. Policies and market forces such as these counteract the effects of modernization in mining operations and subsequently increase CH_4 emissions.

Projected Activity Data

Estimated CH_4 emissions baselines are directly related to coal production projections. Sixty percent of the world's recoverable reserves are located in three regions: the United States (25 percent), FSU (23 percent), and China (12 percent) (USEIA, 2003). China is projected to have the largest increase in coal projections because of rapid economic growth; the country is projected to almost double coal consumption by 2025 (USEIA, 2004a).

Table 1-1: Historical Coal Mining Activity Data for Selected Countries (Million Metric Tons)

Country	1990	1995	2000	2001	2002	2003
China	1,190.4	1,537.0	1,314.4	1,458.7	1,521.2	1,635.0
United States	1,029.1	1,033.0	1,073.6	1,127.7	1,094.3	1,069.5
India	247.6	320.6	370.0	385.4	401.1	403.1
Australia	225.8	266.5	338.2	362.9	376.8	373.4
Russian Federation	NA	270.9	264.9	273.4	261.8	294.0
South Africa	193.2	227.3	248.9	250.8	245.8	263.8
Germany	NA	274.2	226.0	227.1	232.6	229.1
Poland	237.1	221.2	179.5	180.3	178.5	177.8
Indonesia	11.6	45.4	84.4	102.0	113.9	132.4
Ukraine	NA	94.6	69.1	68.0	65.6	63.5
Kazakhstan	NA	93.1	81.5	93.0	89.2	86.4
Greece	57.2	63.6	70.4	73.1	77.7	75.3
Canada	75.3	82.7	76.2	77.6	73.3	68.5
Czech Republic	NA	82.6	71.8	72.9	69.8	70.4
Turkey	52.3	60.6	69.6	68.3	58.7	53.1
Rest of the world	**1,839.9**	**370.0**	**340.9**	**354.9**	**355.4**	**356.4**
World Total	**5,347.6**	**5,096.0**	**4,930.6**	**5,225.3**	**5,259.3**	**5,406.3**

Source: Energy Information Administration (USEIA), 2004a.
NA = data unavailable.
Note: Coal production values include anthracite, bituminous, and lignite coal types.

II.1.2.2 Emissions Factors and Related Assumptions

Historical Emissions Factors

Emissions factors for coal mining vary depending on the type of coal being mined, the depth at which the mining face is located, and how much coal is being produced in a given year. In 2000, emissions factors for 56 gassy mines in the United States ranged from 57 to 6,000 million cubic feet of CH_4 per mine annually. Emissions factors for 34 the Russian Federation gassy mines ranged from 17 to 3,200 million cubic feet per mine. For China's 678 state-run mines, emissions factors ranged from 17 to 6,000 million cubic feet per mine annually from coal production. While the range of emissions factors for the United States and China is similar, China has significantly more mines with higher emissions factors. The Intergovernmental Panel on Climate Change (IPCC) estimates average emissions factors by country. Table 1-2 reports emissions factors for selected countries.

Projected Emissions Factors and Related Assumptions

Improvements made in mining technology throughout the last 20 years have resulted in the ability to extract coal from increasingly greater depths. Developing countries' adoption of advanced mining technology has allowed countries such as China and India to reach deeper into their existing coalbed reserves. As discussed earlier, the volume of CH_4 in the coal seam increases at deeper depths because of increasing geological pressure. Thus, CH_4 emissions will rise as technology allows large coal-producing countries to mine deeper.

Table 1-2: IPCC Suggested Underground Emissions Factors for Selected Countries

Country	Emissions Factor (m^3/ton)	Emissions Factor[a] (tCO_2eq/ton)
FSU	17.8–22.2	0.25–0.32
United States	11.0–15.3	0.16–0.22
Germany	22.4	0.32
United Kingdom	15.3	0.22
Poland	6.8–12.0	0.10–0.17
Czechoslovakia	23.9	0.34
Australia	15.6	0.22

Source: IPCC, 1996. Adapted from Reference Manual Table 1-54.
FSU = Former Soviet Union.
[a] Conversion factor of 1 m^3 = 0.0143 tCO_2eq = 35.31 ft^3 × 0.00404 tCO_2eq

II.1.2.3 Emissions Estimates and Related Assumptions

Historical Emissions Estimates

Baseline emissions for Annex I countries are built using publicly available reports produced by the countries themselves. IPCC's *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* methodology was used to estimate emissions in each country, ensuring comparability across countries (IPCC, 1996). The USEPA's baselines assume a "business-as-usual" scenario that does not include climate change mitigation efforts or other national policies that may indirectly reduce the emissions of greenhouse gases.

Table 1-3 reports countries with the largest historical CH_4 baseline emissions for the years 1990, 1995, and 2000. CH_4 emissions declined worldwide between 1990 and 2000 at an average annual rate of about 10 percent.

Table 1-3: Historical Baseline Emissions for Coal Mine CH_4 for Selected Countries ($MtCO_2eq$)

Country	1990	1995	2000
China	126.1	149.1	117.6
United States	81.9	65.8	56.2
India	10.9	13.7	15.8
Australia	15.8	17.5	19.6
Russian Federation	60.9	36.8	29.0
Ukraine	55.3	30.1	28.3
North Korea	25.3	27.2	26.9
Poland	16.8	15.6	11.9
South Africa	6.7	6.7	7.1
United Kingdom	18.3	12.6	7.0
Germany	25.8	17.6	10.2
Kazakhstan	24.9	17.2	10.0
Colombia	1.9	2.0	3.0
Mexico	1.5	1.8	2.1
Czech Republic	7.6	5.8	5.0
Rest of the world	**37.2**	**32.3**	**27.1**
World Total	**516.7**	**451.5**	**376.9**

Source: USEPA, 2006.

Projected Emissions Estimates

Without the introduction of abatement technologies, worldwide CH_4 emissions from coal mining are projected to increase in the next 20 years. This increase is paralleled by a projected increase in coal consumption over the same period. At the same time, coal's share of overall energy consumption is expected to steadily decrease as a result of technology advances in other energy markets, such as natural gas, and renewed interest in nuclear energy.

Technology adoption and organizational restructuring will improve countries' abilities to produce larger amounts of coal each year. Table 1-4 reports predicted CH_4 baseline emissions for the largest coal-producing countries in the world, assuming the absence of CH_4 abatement technologies.

Table 1-4: Projected Baseline Emissions for Coal Mine CH_4 for Selected Countries ($MtCO_2eq$)

Country	2005	2010	2015	2020
China	135.7	153.8	171.8	189.9
United States	55.3	51.1	46.4	46.4
India	19.5	23.1	28.4	33.6
Australia	21.8	26.4	28.2	29.7
Russian Federation	26.3	27.5	26.9	26.3
Ukraine	26.3	24.5	23.8	23.2
North Korea	25.6	24.3	23.1	21.9
Poland	11.3	10.8	10.3	9.8
South Africa	7.4	7.2	7.1	7.4
United Kingdom	6.7	6.6	6.4	6.2
Germany	8.4	7.7	7.1	5.9
Kazakhstan	6.7	6.4	6.1	5.8
Colombia	3.4	4.0	4.7	5.5
Mexico	2.5	2.8	3.3	3.7
Czech Republic	4.8	3.9	3.1	3.0
Rest of the world	**26.5**	**27.5**	**28.9**	**31.1**
World Total	**388.1**	**407.6**	**425.6**	**449.5**

Source: USEPA, 2006.

II.1.3 Cost of CH_4 Emissions Reductions from Coal Mining

The following is a discussion of the abatement technologies and their costs and benefits.

II.1.3.1 Abatement Option Opportunities

Three abatement opportunities currently available to the coal mining sector are

- degasification,
- enhanced degasification, and
- oxidation of VAM.

Engineering costs for each abatement option are based on representative mine characteristics, such as annual mine production, gassiness of the coal deposits, and CH_4 concentration in ventilation flows. Table 1-5 provides a summary of the one-time investment costs, annual operation and maintenance (O&M) costs, and benefits from using the captured CH_4 as an energy source for each of the three coal mining abatement options included in the analysis.

Table 1-5: Summary of Average Abatement Costs and Benefits for U.S. Coal Mines (in 2000$)[a]

	Average Costs/Benefits (Millions in 2000$)		
Costs	**Degasification**	**Enhanced Degasification[b]**	**VAM[c]**
One-Time Costs			
Compressor capital	$1.00	$0.39	N/A
Gathering line capital	$0.90	$0.20	N/A
Processing capital	$0.04	$2.56	N/A
Ventilation capital	N/A	N/A	$18.64
Miscellaneous capital	$0.38	$0.14	N/A
Annual Costs			
Drilling capital	$0.50	$0.36	N/A
Drilling materials	$0.94	$0.31	N/A
Compressors energy (kWh)	$0.33	$0.13	N/A
Gathering lines labor	$0.25	$0.96	N/A
Processing materials	$0.13	$0.18	N/A
Ventilation operating costs	N/A	N/A	$0.91
Miscellaneous labor	$0.28	$0.12	N/A
Annual After-Tax Benefits			
CH_4 sold or purchases offset	$0.97	$0.34	$2.78
Depreciation Tax Benefits	$0.02	$0.24	$0.14

Source: Gallaher and Delhotal, 2005.
N/A = Not applicable.
[a] Based on a population of 57 U.S. coal mines, accounting for 75 percent of the total liberated CH_4 from U.S. coal production.
[b] Incremental costs and benefits in addition to degasification (Option 1).
[c] Underlying VAM costs are from Delhotal et al. (2005).

Degasification and Pipeline Injection

High-quality CH_4 is recovered from coal seams by drilling vertical wells up to 10 years in advance of a mining operation or drilling horizontal boreholes up to 1 year before mining. Most mine operators exercise just-in-time management of gate road development; subsequently, horizontal cross-panel boreholes are installed and drain gas for 6 months or less. Long horizontal boreholes are used by only a few operators in the United States and Australia.

In some cases, high-quality CH_4 also can be obtained from gob wells. Gob gas CH_4 concentrations can range from 50 percent to over 90 percent (USEPA, 1999). The gas recovered is injected into a natural gas pipeline requiring virtually no purification in the initial stages of production, but necessitating treatment over time to upgrade the gas to pipeline quality. Gob gas sales from a given location typically decline over time because of declining levels of concentration. In the United States, of the CH_4 recovered from degasification (or gas drainage as it is often called) 57 percent can be directly used for pipeline injection (USEPA, 1999).

Cost Analysis

- **Capital Costs.** Capital costs include the one-time (upfront) costs of purchasing compressors, gathering lines, dehydrators, and other miscellaneous capital such as safety equipment and licenses. Table B-6 in Appendix B for this chapter offers a detailed description of the factors that determine the required number of each capital component by mine.
- **Annual Costs.** These costs include materials and labor for drilling, moving gathering lines, and maintaining the dehydrators. Drilling capital is also considered an annual cost because drilling is conducted annually. Annual costs generally increase or decrease proportionally to the volume of CH_4 liberated at the individual mine. Table B-6 offers a detailed description of the factors that determine these costs.
- **Cost Savings.** Cost savings result from the capture and reuse of natural gas. For basic degasification, it is assumed that 57 percent of gas capture is suitable for injection into the natural gas pipelines and hence can be sold directly into the system (USEPA, 1999).

Enhanced Degasification and Pipeline Injection

In enhanced degasification, CH_4 is recovered in the same way as in degasification, using vertical wells, horizontal boreholes, and gob wells. In addition, the mine invests in enrichment technologies such as nitrogen removal units (NRUs) and dehydrators, used primarily to enhance medium-quality gob well gas by removing impurities, allowing for larger quantities of CH_4 to be captured and used. This option also assumes tighter well spacing to increase recovery. The enrichment process and tighter spacing improve recovery efficiency 20 percent more than the first option discussed above (USEPA, 1999). All costs and benefits presented in Table 1-5 for enhanced degasification are incremental in that they represent additional abatement costs and CH_4 sales above and beyond the basic degasification.

Cost Analysis

- **Capital Costs.** Enhanced degasification requires the same capital equipment as the degasification option. In addition, the enhanced option requires an NRU with an estimated average cost of $200,000 per unit.
- **Annual Costs.** Similar to degasification, enhanced degasification's annual costs include materials and labor for drilling, moving gathering lines, and maintaining the dehydrators. However, annual drilling costs are higher for enhanced degasification because the wells are drilled at closer intervals to one another. Costs vary proportionally to the amount of gas liberated.
- **Cost Savings.** It is assumed that 77 percent of the CH_4 captured as part of enhanced degasification can be injected into the natural gas pipeline system. There is a 21 percent increase over the basic degasification mitigation option (incremental benefits) because gas processing equipment facilitates nitrogen removal.

Oxidation of Ventilation Air Methane

Oxidation technologies (both thermal and catalytic) have the potential to use CH_4 emitted from coal mine ventilation air. It is not economically feasible to sell this gas to a pipeline because of its extremely low CH_4 concentration levels (typically below 1 percent). However, VAM can be oxidized to generate CO_2 and heat, which in turn may be used directly to heat water or to generate electricity. If oxidizer technology were applied to all mine ventilation air with concentrations greater than 0.15 percent CH_4, approximately 97 percent of the CH_4 from the ventilation air could be mitigated.

Cost Analysis

- **Capital Costs.** Capital costs for VAM oxidation are a function of the level of CH_4 concentration in the ventilation air and the ventilation air flow rate.
- **Annual Costs.** Annual costs consist primarily of the labor and electricity costs associated with running the oxidizer. Both of these are proportional to coal production.
- **Cost Savings.** Heat generated by oxidation systems can be used to heat water (e.g., for steam or district heating applications) or to generate electricity.

II.1.4 Results

This section presents the Energy Modeling Forum (EMF) Working Group 21 study's MAC analysis results in tabular format.

II.1.4.1 Data Tables and Graphs

Table 1-6 presents the average breakeven price and the reduction in absolute and percentage terms for the mitigation options discussed in Section II.1.3.1.

Table 1-6: Summary of Coal Mining Abatement Options Included in the Analysis

Technology	Breakeven Cost ($/t$CO_2$eq)	Emissions Reduction (% from baseline)	Emissions Reduction in 2010 (MtCO_2eq)	Emissions Reduction in 2020 (MtCO_2eq)
	Assuming a 10% discount rate and a 40% tax rate			
Degasification and pipeline injection	–$11.66	28%	0.55	0.55
Enhanced degasification, gas enrichment, and pipeline injection	$2.40	10%	0.19	0.19
Catalytic oxidation[a] (United States)	$14.36	24%	0.77	0.94
Flaring	$2.47	1%	0.03	0.03
Degasification and power production—A	–$2.09	5%	0.04	0.03
Degasification and power production—B	$5.68	9%	0.06	0.06
Degasification and power production—C	$19.80	28%	0.70	0.83
Catalytic oxidation (EU-15)	$11.34	18%	0.13	0.11

Source: USEPA, 2003. Adapted from Coal Sector technology tables in Appendix B of EMF report.
EU-15 = European Union.
Note: Some technologies are not present in all countries. See source for the individual technology's presence in various countries.
[a] Catalytic oxidation is considered a VAM technology.

The EMF regional baselines and MAC results of the EMF-21 study are presented in Tables 1-7 and 1-8 for 2010 and 2020 using the base energy price, a 10 percent discount rate, and a 40 percent tax rate. These MACs represent percentage reductions in baseline emissions for individual regions/countries at selected breakeven prices. Figure 1-2 provides MACs for the five EMF countries/regions with the largest estimated emissions from coal mining in 2020.

The MACs presented in this section represent static abatement curves using breakeven prices built on the assumption of fixed mitigation cost and aggregate countrywide natural gas statistics. Appendix B presents more recent efforts to develop an alternative framework for conducting MAC analysis that addresses the limitations of the EMF-21 MAC analysis.

Table 1-7: Baseline Emissions by EMF Regional Grouping: 2000–2020 ($MtCO_2eq$)

Country/Region	2000	2010	2020
Africa	9.3	8.2	8.7
Annex I	**181.9**	**173.5**	**165.8**
Australia/New Zealand	20.0	26.8	30.3
Brazil	1.3	1.1	1.0
China	117.6	153.8	189.9
Eastern Europe	24.3	23.4	24.1
EU-15	22.5	19.6	17.0
India	15.8	23.1	33.6
Japan	0.8	0.7	0.7
Mexico	2.1	2.8	3.7
Non-OECD Annex I	**61.7**	**56.8**	**54.7**
OECD	**123.5**	**120.2**	**115.3**
Russian Federation	29.0	27.5	26.3
South & SE Asia	31.7	29.8	28.4
United States	56.2	51.1	46.4
World Total	**376.9**	**407.6**	**449.5**

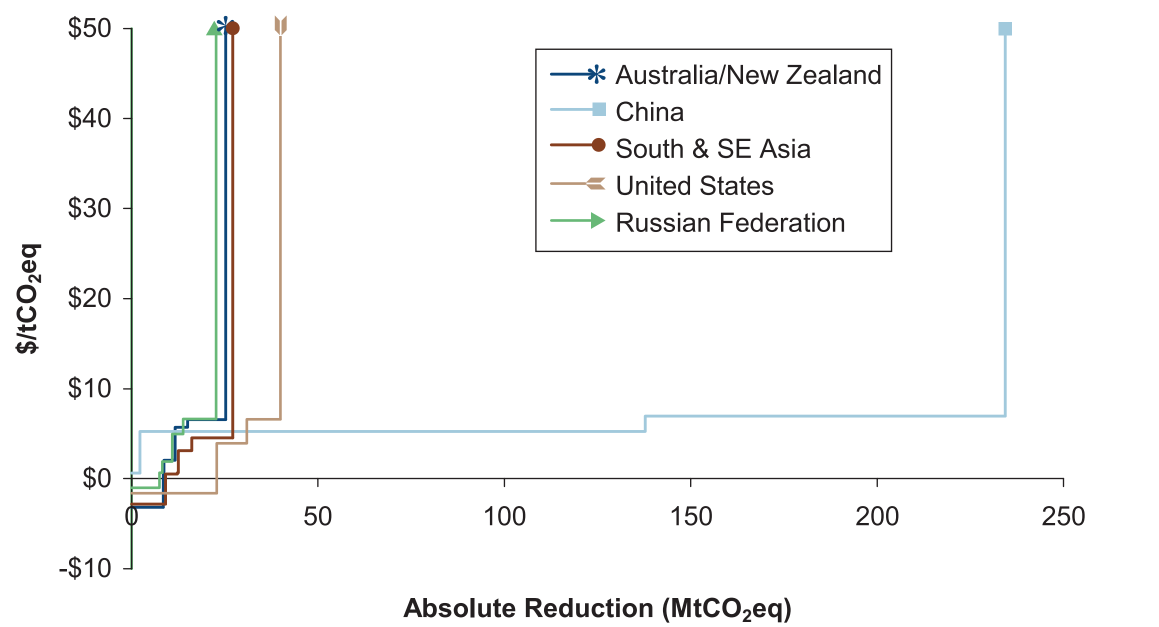
Source: USEPA, 2006.
EU-15 = European Union; OECD = Organisation for Economic Co-operation and Development.
Note: World Total does not equal the sum of the countries listed in this table because the regional groupings are a subset of the full EMF regional grouping list. See Appendix A of this report for the full EMF list of countries by region.

Table 1-8: Coal Mining MACs for Countries Included in the Analysis

	2010					2020				
Country/Region	**$0**	**$15**	**$30**	**$45**	**$60**	**$0**	**$15**	**$30**	**$45**	**$60**
Africa	38.50%	85.53%	85.53%	85.53%	85.53%	38.50%	85.53%	85.53%	85.53%	85.53%
Annex I	**34.81%**	**78.05%**	**78.05%**	**78.05%**	**78.05%**	**36.33%**	**81.45%**	**81.45%**	**81.45%**	**81.45%**
Australia/New Zealand	27.91%	83.05%	83.05%	83.05%	83.05%	27.91%	83.05%	83.05%	83.05%	83.05%
Brazil	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
China	0.00%	84.45%	84.45%	84.45%	84.45%	0.00%	84.45%	84.45%	84.45%	84.45%
Eastern Europe	34.16%	73.23%	73.23%	73.23%	73.23%	34.16%	73.23%	73.23%	73.23%	73.23%
EU-15	0.00%	41.11%	41.11%	41.11%	41.11%	0.00%	41.11%	41.11%	41.11%	41.11%
India	0.00%	84.18%	84.18%	84.18%	84.18%	0.00%	84.18%	84.18%	84.18%	84.18%
Japan	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
Mexico	28.50%	85.53%	85.53%	85.53%	85.53%	28.50%	85.53%	85.53%	85.53%	85.53%
Non-OECD Annex I	**32.10%**	**84.80%**	**84.80%**	**84.80%**	**84.80%**	**39.21%**	**103.58%**	**103.58%**	**103.58%**	**103.58%**
OECD	**35.40%**	**75.22%**	**75.22%**	**75.22%**	**75.22%**	**34.95%**	**74.26%**	**74.26%**	**74.26%**	**74.26%**
Russian Federation	27.65%	84.29%	84.29%	84.29%	84.29%	27.65%	84.29%	84.29%	84.29%	84.29%
South & SE Asia	28.15%	84.09%	84.09%	84.09%	84.09%	28.15%	84.09%	84.09%	84.09%	84.09%
United States	49.22%	85.97%	85.97%	85.97%	85.97%	49.22%	85.97%	85.97%	85.97%	85.97%
World Total	**16.66%**	**79.84%**	**79.84%**	**79.84%**	**79.84%**	**14.51%**	**79.81%**	**79.81%**	**79.81%**	**79.81%**

Source: USEPA, 2003.
EU-15 = European Union; OECD = Organisation for Economic Co-operation and Development.

Figure 1-2: EMF MACs for Top Five Emitting Countries/Regions from Coal: 2020



Source: USEPA, 2003.
Note: Regional MACs were constructed using percentage reductions from USEPA (2003), with baselines from USEPA (2005).

II.1.4.2 Uncertainties and Limitations

Several key limitations in current data availability constrain the accuracy of this analysis. Successfully addressing these issues would improve development of the MACs and predictions of their behavior as a function of time. Some of these limitations include the following.

- **Accurate Distribution of Mine Type for Each Country.** Extrapolating from available information about individual mines to project fugitive emissions at a national level implies that the available data are representative of the country's coal production not already included in the existing database. A more accurate distribution of representative mines would improve the accuracy of the cost estimates and the shape of each MAC. These data would include mines of all sizes, emissions factors, and production levels. This lack of information becomes increasingly problematic when evaluating a country such as China, where the majority of mines are small, private mines that are not represented in currently available data sources.
- **Country-Specific Tax and Discount Rates.** In this analysis, a single tax rate is applied to mines in all countries to calculate the annual benefits of each technology. In reality, however, tax rates vary across countries, and in the case of state-run mines in China, taxes may not even be applicable. Similarly, the discount rate may vary by country. Improving the level of country-specific detail will help analysts more accurately quantify benefits and breakeven prices.
- **Improved Information on Public Infrastructure.** A more detailed understanding of each country's natural gas infrastructure would improve the estimates of costs associated with transporting CH_4 from a coal mine to the pipeline. Countries with little infrastructure will have a much higher transportation cost associated with degasification and enhanced degasification technologies.

- **Concentrations for VAM in International Mines.** The effectiveness and applicability of VAM technology depends on VAM concentration and mine-specific coal production rates. Improved data on the VAM concentration levels for individual mines would enhance the accuracy of cost estimates. This information would also help to more accurately identify the minimum threshold concentration levels that make VAM oxidation an economically viable option.

II.1.5 Summary

The methodology and data discussed in this section describe the MAC analysis conducted for the coal mining sector by the EMF-21 study. MACs for 2010 and 2020 were estimated based on aggregated industry data from each country or region. The MACs represent static estimates of potential CH_4 mitigation from coal mines based on available information regarding infrastructure and country-reported emissions estimates provided through the United Nation's Framework Convention on Climate Change emissions inventory reports.

II.1.6 References

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Explanatory Notes

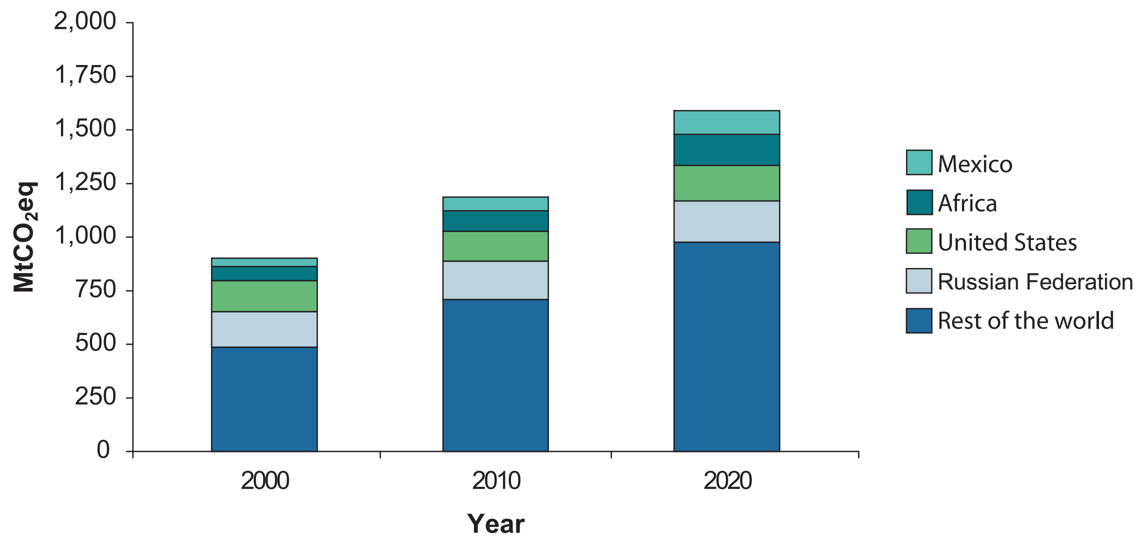
1. Bleeder shafts are currently used in only a limited number of countries, including the United States and the Russian Federation.

2. There are exceptions. In Kazakhstan, for example, the surface mines in Ekibastuz are very gassy and prone to outbursts; this is the rare exception, though.

II.2 Natural Gas Sector

Natural gas systems are a leading source of anthropogenic CH_4 emissions, accounting for more than 970 $MtCO_2eq$ (USEPA, 2006). The USEPA estimates that natural gas systems account for 8 percent of total global CH_4 emissions. The Russian Federation, the United States, Africa, and Mexico account for more than 43 percent of the world's CH_4 emissions in the natural gas sector (USEPA, 2006) (Figure 2-1).

Figure 2-1: CH_4 from Natural Gas Systems by Country: 2000–2020



Source: USEPA, 2006.

Emissions are projected to increase 54 percent from 2005 to 2020, with Brazil and China having the largest growth of 737 percent and 611 percent, respectively (USEPA, 2006). The two regions projected to experience the largest growth in production are the Middle East and the developing countries of Latin America.

II.2.1 Introduction

Natural gas systems include the production, processing, transportation and storage, and distribution of natural gas. Table 2-1 identifies facilities and equipment associated with different segments of the natural gas system.

During production, gas exit swells under pressure greater than 1,000 pounds per square inch (psi). The gas is routed through dehydrators, where water and other liquids are removed, and then to small-diameter gathering lines for transport to either processing plants or injection directly into transmission or distribution pipelines. Processing plants further purify the gas by removing natural gas liquids, sulfur compounds, particulates, and CO_2. Impurities in the gas are extracted through a cooling process that forces the impurities to condense into a liquid, which is then vaporized in a reboiler and vented into the atmosphere.

Table 2-1: Natural Gas Industry Characterization

Segment	Facility	Equipment at the Facility
Production	Wells, central gathering facilities	Wellheads, separators, pneumatic devices, chemical injection pumps, dehydrators, compressors, heaters, meters, pipelines
Processing	Gas plants	Vessels, dehydrators, compressors, acid gas removal (AGR) units, heaters, pneumatic devices
Transmission and storage	Transmission pipeline networks, compressor stations, meter and pressure-regulating stations, underground injection/withdrawal facilities, liquefied natural gas (LNG) facilities	Vessels, compressors, pipelines, meters/pressure regulators, pneumatic devices, dehydrators, heaters
Distribution	Main and service pipeline networks, meter and pressure-regulating stations	Pipelines, meters, pressure regulators, pneumatic devices, customer meters

Source: USEPA, 1996.

Processed gas, which is 95 percent CH_4, is then injected into large-diameter transmission pipelines, where it is compressed and transported to storage and distribution facilities. Storage stations are either above- or belowground facilities and include compressor stations. Distribution companies reduce high-pressure gas (averaging 300 psi to 600 psi) to pounds or even ounces per square inch for delivery to homes, businesses, and industries.

CH_4 emissions occur from normal operations in each of the four segments of the natural gas industry. Equipment/pipeline leaks and venting activities are the primary sources of CH_4 emissions in the natural gas sector (USEPA, 1996). As the gas moves through system components under extreme pressure, CH_4 can escape to the atmosphere through worn valves, flanges, pump seals, compressor seals, and joints or connections in gathering pipelines. For example, in the production segment of the natural gas system, emissions occur at the wellhead, during dehydration, and when the gas is compressed to be transported from the wellhead site to a processing plant. CH_4 emissions also occur during routine maintenance throughout the natural gas system. For example, emissions from the transmission segment include intentional blowdown or purge activities during maintenance and inspection.

Abatement options for the natural gas sector generally fall into three categories: equipment changes/upgrades, changes in operational practices, and direct inspection and maintenance (DI&M). Many abatement options are applicable across all four segments of the natural gas system described in Table 2-1.

- Natural gas emissions from pneumatic control devices are one of the largest sources of CH_4 emissions in the natural gas industry. Substituting compressed air for pressurized natural gas throughout the natural gas system eliminates the constant bleed of natural gas to the atmosphere.
- Changing operational practices, such as using pumpdown techniques to remove product (i.e., natural gas) from sections of pipeline and the compressor during maintenance and repair, reduces the volume of natural gas vented to the atmosphere when components are taken offline.
- Implementing DI&M programs can eliminate as much as 80 percent of fugitive CH_4 emissions that result from equipment and pipeline leaks throughout the system.

The following sections discuss the activity data and emissions factors used to develop baseline emissions, abatement options and their costs, and CH_4 MACs for natural gas systems for selected countries. The chapter concludes with sensitivity analyses on key assumptions and a discussion of uncertainties and limitations.

II.2.2 Baseline Emissions Estimates

Annual emissions baselines for natural gas systems are calculated using activity factors, activity factor drivers, and emissions factors. Each of these factors can be affected by variations in individual countries' production process techniques, the intensity of maintenance schedules, and the age of the natural gas system. Table C-7 (see Appendix C) lists the activity factors, emissions factors, and emissions for sources in the United States.

II.2.2.1 Activity Data

Activity factors and activity factor drivers are used to estimate the population of equipment in each segment of the natural gas system.

Activity Factors

Activity factors include both the physical number of units and the level of operation/activity of these units. These factors inform the underlying population for each type of equipment present in a natural gas system. Examples of activity factors include the number of compressors in the production segment, the throughput across segments, miles of pipeline, number of blowdowns, and the total number of gas wells. Activity factors are used in conjunction with emissions factors (discussed below) to calculate annual baseline emissions. This report uses activity factors used to characterize the U.S. natural gas system in 1992 (USEPA, 1996).

Activity Factor Drivers

Activity factor drivers are used to adjust the activity factors from 1992 to reflect changes over time or differences between countries. The primary drivers are changes in production and consumption levels, but drivers can also include changes in the age or underlying technology of natural gas systems. Activity factor drivers determine how the equipment population numbers fluctuate in response to expanding or contracting natural gas markets. For example, the number of dehydrators in a natural gas system is determined by the number of wells, which is driven by production levels. If production of natural gas drops, the number of wells required decreases. This drives down the number of dehydrators in operation (or the operating capacity of dehydrators in place), reducing the baseline emissions estimate.

Historical Activity Data

Historically, natural gas has been produced by developed countries, which have the technology base and capital available to facilitate the development of natural gas industries. In 2001, the FSU and the United States accounted for 33 percent of the world's natural gas production (91.1 trillion cubic feet) (USEIA, 2005a). Table 2-2 reports natural gas production by country and region for 1980 through 2003.

During the past 20 years, natural gas consumption has increased (see Table 2-3). Developing countries have experienced the largest increase in consumption in recent years, while industrialized countries have experienced small but steady growth over the same period. Currently, developing countries consume significantly less natural gas than developed countries; however, this trend is projected to change in the next 5 to 10 years.

Table 2-2: Natural Gas Production by Country and Region: 1980–2003 (Trillion Cubic Feet)

Country/Region	1980	1990	1995	2000	2001	2002	2003
Canada	2.76	3.85	5.60	6.47	6.60	6.63	6.45
Mexico	0.90	0.90	0.96	1.31	1.30	1.33	1.49
United States	19.40	17.81	18.60	19.18	19.62	18.93	19.04
North America	**23.06**	**22.56**	**25.16**	**26.97**	**27.51**	**26.89**	**26.98**
Antarctica	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Central and South America	**1.23**	**2.01**	**2.58**	**3.43**	**3.65**	**3.72**	**4.20**
Netherlands	3.40	2.69	2.98	2.56	2.75	2.66	2.58
Norway	0.92	0.98	1.08	1.87	1.95	2.41	2.59
United Kingdom	1.32	1.75	2.67	3.83	3.69	3.61	3.63
Western Europe	**7.46**	**7.24**	**8.80**	**10.19**	**10.27**	**10.55**	**10.62**
Russian Federation	NA	NA	21.01	20.63	20.51	21.03	21.77
Turkmenistan	NA	NA	1.14	1.64	1.70	1.89	2.08
Uzbekistan	NA	NA	1.70	1.99	2.23	2.04	2.03
Eastern Europe and FSU	**17.06**	**30.13**	**25.93**	**26.22**	**26.48**	**27.05**	**28.00**
Iran	0.25	0.84	1.25	2.13	2.33	2.65	2.79
Saudi Arabia	0.33	1.08	1.34	1.76	1.90	2.00	2.12
United Arab Emirates	0.20	0.78	1.11	1.36	1.39	1.53	1.58
Middle East	**1.42**	**3.72**	**4.99**	**7.57**	**7.98**	**8.67**	**9.12**
Algeria	0.41	1.79	2.05	2.94	2.79	2.80	2.91
Africa	**0.69**	**2.46**	**3.01**	**4.44**	**4.63**	**4.74**	**5.07**
Indonesia	0.63	1.53	2.24	2.36	2.34	2.48	2.62
Malaysia	0.06	0.65	1.02	1.50	1.66	1.71	1.89
Asia and Oceania	**2.44**	**5.44**	**7.50**	**9.48**	**9.92**	**10.53**	**11.19**
World Total	**53.35**	**73.57**	**77.96**	**88.29**	**90.45**	**92.15**	**95.18**

Source: USEIA, 2005b.
FSU = Former Soviet Union; NA = Data unavailable.

Projected Activity Data

Production and consumption of natural gas are expected to increase in the near term, with developing countries experiencing the largest percentage increases over the next 20 years. Table 2-4 and Table 2-5 list projected natural gas production and consumption, respectively, by selected country and region from 2010 to 2025. Annual growth in production in Central and South America and Africa is expected to approach 5 percent. However, the United States, Eastern Europe, and the FSU are still projected to account for more than 50 percent of world natural gas production in 2025 (USEIA, 2004).

Natural gas is projected to be the fastest growing source of primary energy over the next 20 years. Consumption is expected to increase by more than 70 percent (average annual rate of 2.2 percent) from 2001 to 2025 (USEIA, 2005a). Developing countries will continue to experience the largest percentage increases in demand.

Table 2-3: Natural Gas Consumption by Country and Region: 1980–2003 (Trillion Cubic Feet)

Country/Region	1980	1990	1995	2000	2001	2002	2003
Canada	1.88	2.38	2.79	2.95	2.91	3.06	3.21
Mexico	0.80	0.92	1.04	1.40	1.40	1.50	1.82
United States	19.88	19.17	22.21	23.33	22.24	23.01	22.38
North America	**22.56**	**22.47**	**26.04**	**27.68**	**26.55**	**27.57**	**27.41**
Central and South America	**1.24**	**2.02**	**2.58**	**3.30**	**3.54**	**3.56**	**3.82**
France	0.98	1.00	1.18	1.40	1.47	1.59	1.54
Germany	NA	NA	3.17	3.10	3.24	3.20	3.32
Italy	0.97	1.67	1.92	2.50	2.51	2.49	2.72
Netherlands	1.49	1.54	1.70	1.73	1.77	1.76	1.78
United Kingdom	1.70	2.06	2.69	3.37	3.34	3.31	3.36
Western Europe	**8.66**	**10.50**	**12.76**	**15.13**	**15.51**	**15.87**	**16.43**
Russian Federation	NA	NA	14.51	14.13	14.41	14.57	15.29
Ukraine	NA	NA	2.97	2.78	2.62	2.78	3.02
Uzbekistan	NA	NA	1.35	1.51	1.60	1.64	1.67
Eastern Europe and FSU	**15.86**	**27.83**	**23.04**	**22.80**	**23.30**	**23.68**	**24.97**
Iran	0.23	0.84	1.24	2.22	2.48	2.80	2.79
Saudi Arabia	0.33	1.08	1.34	1.76	1.90	2.00	2.12
United Arab Emirates	0.11	0.66	0.88	1.11	1.15	1.29	1.34
Middle East	**1.31**	**3.60**	**4.74**	**6.82**	**7.05**	**7.63**	**7.86**
Africa	**0.74**	**1.35**	**1.69**	**2.04**	**2.28**	**2.45**	**2.55**
China	0.51	0.49	0.58	0.93	1.05	1.13	1.18
Indonesia	0.20	0.55	1.06	1.08	1.18	1.20	1.23
Japan	0.90	1.85	2.21	2.84	2.84	2.94	3.05
Asia and Oceania	**2.52**	**5.61**	**7.79**	**10.43**	**11.08**	**11.76**	**12.46**
World Total	**52.89**	**73.37**	**78.64**	**88.21**	**89.31**	**92.51**	**95.50**

Source: USEIA, 2005b.
FSU = Former Soviet Union; NA = Data unavailable.

II.2.2.2 Emissions Factors and Related Assumptions

Emissions factors in the natural gas sector are defined as the rate of CH_4 emissions from a facility or piece of equipment or from normal operations and routine maintenance. Estimated emissions factors are used in conjunction with activity factors and activity factor drivers to generate baseline emissions estimates by country. Table 2-6 reports estimated emissions factors by country, provided by IPCC's *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*. These emissions factors represent the average estimated emissions factor across all segments of the natural gas system.

The system-level emissions factors in Table 2-6 are used to calculate country-specific baseline emissions (see Section II.2.2.3) for countries outside the United States. For the United States, a more detailed set of emissions factors is used to calculate baseline emissions. Appendix Table C-7 presents the individual facility and equipment emissions factors estimated for the U.S. natural gas system, adapted from the USEPA report *Methane Emissions form the Natural Gas Industry* (USEPA, 1996).

This section discusses the source of the emissions factors used to develop country-specific baseline emissions.

Table 2-4: Projected Natural Gas Production by Country and Region: 2010–2025 (Trillion Cubic Feet)

Country/Region	2010	2015	2020	2025	Average Annual Percentage Change, 2001–2025
Canada	7.6	7.5	7.1	7.5	0.5
Mexico	1.5	1.6	1.9	2.1	2.0
United States	20.5	21.6	23.8	24.0	0.8
North America	**29.6**	**30.6**	**32.8**	**33.6**	**0.8**
Central and South America	**5.5**	**7.1**	**8.6**	**10.6**	**4.6**
Western Europe	**9.0**	**9.0**	**8.9**	**9.8**	**–0.2**
Eastern Europe and FSU	**31.0**	**35.7**	**40.4**	**45.3**	**2.2**
Middle East	**9.8**	**12.1**	**15.6**	**18.8**	**3.5**
Africa	**8.1**	**9.9**	**11.9**	**14.1**	**4.8**
China	1.6	1.9	2.3	3.1	4.5
Asia	**12.5**	**14.2**	**16.3**	**18.8**	**2.6**
World Total	**105.5**	**118.5**	**134.5**	**151.0**	**2.1**

Source: USEIA, 2004.
FSU = Former Soviet Union.

Table 2-5: Projected Natural Gas Consumption by Country and Region: 2010–2025 (Trillion Cubic Feet)

Country/Region	2010	2015	2020	2025	Average Annual Percentage Change, 2001–2025
Canada	3.9	4.3	4.6	4.7	2.0
Mexico	1.8	2.2	2.6	3.0	3.0
United States	25.6	28.3	30.4	30.9	1.3
North America	**31.3**	**34.8**	**37.6**	**38.6**	**1.5**
Brazil	0.9	1.3	1.7	2.1	6.8
Other Central/South America	**3.8**	**4.3**	**4.8**	**5.4**	**2.4**
Western Europe	**17.3**	**19.0**	**20.4**	**22.4**	**1.8**
Russian Federation	16.2	17.9	19.5	20.7	1.5
Eastern Europe	**4.0**	**4.6**	**5.2**	**5.8**	**3.5**
FSU	**25.6**	**29.0**	**31.0**	**33.3**	**2.0**
Middle East	**10.6**	**12.6**	**14.5**	**16.6**	**3.1**
Africa	**3.1**	**4.1**	**4.9**	**6.0**	**4.0**
China	2.6	3.4	4.2	6.5	7.8
Emerging Asia	**10.6**	**13.3**	**16.3**	**20.7**	**4.3**
World Total	**111.4**	**127.9**	**141.6**	**156.2**	**2.3**

Source: USEIA, 2005c.
FSU = Former Soviet Union.

Table 2-6: IPCC Estimated Emissions Factors from Natural Gas by Region

Country/Region	Emissions Factors by Industry Segment (kg/petajoule) Production	Consumption
Eastern Europe/FSU[a]	392,800	527,900
Other oil-exporting countries[b]	67,795	228,310
United States and Canada	71,905	88,135
Western Europe[c]	20,900	84,500
Rest of the world[d]	67,795	228,310

Source: IPCC, 1996. Adapted from Reference Manual Tables 1-60, 1-61, 1-62, 1-63, and 1-64.
FSU = Former Soviet Union
[a] Includes Albania, Bulgaria, Czech and Slovak Republics, Hungary, Poland, Romania, and the former Yugoslavia.
[b] Includes Algeria, Nigeria, Venezuela, Indonesia, Iran, Iraq, Kuwait, Saudi Arabia, United Arab Emirates, Ecuador, and Mexico.
[c] Includes Austria, Belgium, Denmark, Faroe Islands, Finland, France, Germany, Gibraltar, Greece, Iceland, Ireland, Italy, Luxembourg, Malta, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, and the United Kingdom.
[d] Includes Asia, Africa, Middle East, Oceania, and Latin America.

Historical Emissions Factors

The United States conducted a study to measure and estimate emissions factors for all components in its national infrastructure (USEPA, 1996). This study measured or estimated emissions factors for more than 100 pieces of natural gas equipment, such as gas wells, compressors, pipeline, and system upsets. The study was conducted in 1992, and the emissions factors were revised and published in 1996. Table C-7 (see Appendix C) lists the study's emissions factors by component and segment of the infrastructure. These emissions factors are used to calculate the U.S. baseline emissions estimate (see Table 2-7). For all other countries, IPCC systems emissions factors (Table 2-6) were used to develop baseline emissions estimates.

Table 2-7: Baseline Emissions for Natural Gas Systems for Selected Countries: 1990–2000 ($MtCO_2eq$)

Country	1990	1995	2000
Russian Federation	334.3	240.6	165.3
United States	143.9	148.0	145.7
Iran	19.4	29.1	34.6
Mexico	22.7	25.3	37.4
Ukraine	78.3	81.8	86.9
Turkmenistan	19.5	16.7	24.3
Nigeria	12.5	17.6	37.8
Venezuela	29.8	34.8	37.7
Turkey	19.9	28.5	38.7
India	8.0	12.5	15.8
United Arab Emirates	18.9	26.7	33.2
Uzbekistan	27.2	30.3	34.8
Indonesia	31.3	41.4	42.1
Canada	25.4	34.3	37.3
Argentina	8.0	10.9	14.9
Rest of the world	**132.0**	**145.3**	**186.0**
World Total	**931.0**	**923.8**	**972.4**

Source: USEPA, 2006.

Projected Emissions Factors and Related Assumptions

Over time, the USEPA estimates that the proportional growth in baseline CH_4 globally will slow relative to the growth in overall production and consumption. Emissions factors in mature natural gas systems are projected to increase because of equipment age and fatigue. However, this increase will be counterbalanced by rapidly expanding industries in developing countries that will employ state-of-the-art technology when constructing natural gas infrastructures.

For example, China is in the early stages of developing a natural gas infrastructure. China's use of state-of-the-art technology supplied by the United States, the European Union (EU), and Japan will result in low emissions factors, and these low emissions factors will constrain the growth in China's national baseline emissions over time.

II.2.2.3 Emissions Estimates and Related Assumptions

The USEPA estimates the emissions contribution of each segment in the natural gas system by multiplying emissions factors (EF) by associated activity factors (AF) and then summing them, as shown below:

$$\begin{aligned} \textit{Country Total Emissions} = \;& \textit{Production } (EF \times AF) + \textit{Processing } (EF \times AF) + \\ & \textit{Transport } (EF \times AF) + \textit{Storage } (EE \times AF) + \\ & \textit{Distribution } (EF \times AF) \end{aligned} \tag{2.1}$$

From Equation (2.1), individual country baseline estimates using natural gas production and consumption data are coupled with the IPCC system emissions factors presented in Table 2-6. This section discusses the historical and projected changes in the baseline emissions estimates.

Historical Emissions Estimates

Baseline emissions are built using publicly available reports produced by the countries themselves. IPCC guidelines and methods were used to estimate emissions in each country, ensuring comparability across countries. Table 2-7 presents the countries with the largest historical CH_4 baseline emissions for 1990, 1995, and 2000. CH_4 emissions increased worldwide from 1990 to 2000 at an average annual rate of 3 percent.

Projected Emissions Estimates

Overall, world CH_4 emissions are expected to increase during the next 20 years at an average annual rate of 5.7 percent (USEPA, 2003a), reflecting a projected increase in natural gas use as a share of total energy consumption. Table 2-8 presents the predicted CH_4 baseline emissions for the largest emitting countries in the global natural gas sector. Developing countries will experience the largest percentage increases in emissions, which closely parallel expected increases in consumption and production of natural gas. However, the level of technology employed in building new infrastructure will help constrain baseline emissions for these countries.

Table 2-8: Projected Baseline Emissions for Natural Gas Systems for Selected Countries: 2005–2020 ($MtCO_2eq$)

Country	2005	2010	2015	2020
Russian Federation	171.9	178.6	185.8	193.1
United States	124.3	138.6	151.0	164.8
Iran	56.8	74.0	96.4	125.3
Mexico	49.5	64.0	82.6	111.4
Ukraine	90.4	93.9	97.7	101.5
Turkmenistan	46.2	72.1	83.2	93.9
Nigeria	49.1	59.2	73.3	89.4
Venezuela	45.2	50.7	63.0	84.8
Turkey	50.2	56.6	62.9	75.5
India	25.8	35.7	49.5	61.4
United Arab Emirates	38.7	47.4	52.8	59.7
Uzbekistan	39.6	44.3	45.4	46.8
Indonesia	46.8	48.0	46.3	45.2
Canada	37.3	38.2	39.8	41.1
Argentina	14.9	16.7	20.9	28.1
Rest of the world	**213.8**	**253.4**	**313.0**	**373.8**
World Total	**1,100.4**	**1,271.5**	**1,463.7**	**1,695.8**

Source: USEPA, 2006.

II.2.3 Cost of CH_4 Emissions Reductions from Natural Gas Systems

Capital costs, annual costs, and annual benefits for individual abatement options are obtained from the USEPA's economic cost model. The economic cost model incorporates activity and emissions factors published by the USEPA and the Gas Research Institute (GRI) (USEPA, 1996). The USEPA's economic cost model reports one-time capital costs, annual operating costs, and reduction efficiencies for 118 different abatement options applied across the four sectors: production, processing, transmission and storage, and distribution. Options range from upgrading compressors and pipes to enhancing inspection and detection techniques. The number of options by sector is presented in Table 2-9. Table C-8 (in Appendix C) contains a brief description of the major categories of natural gas abatement options.

It should be noted that a large number of abatement options for the natural gas sector are substitutes for each other. Thus, there may be several options for reducing emissions for a particular piece of equipment, but only one may be selected. For example, DI&M of gas wells is substitutable with enhanced DI&M. In developing the MACs, the model chooses between substitute options, selecting the option with the lowest breakeven price.

Table 2-9: Prevalence of Abatement Options by Infrastructure Component

Infrastructure Component	Total
Production	39
Processing	2
Transmission and storage	51
Distribution	26

Source: USEPA, 2000.

II.2.3.1 Abatement Option Opportunities

This section presents a general overview of the applicable abatement options for each segment of the natural gas system, followed by a more detailed discussion of the costs and benefits of selected abatement options. Engineering cost and benefit estimates represent equipment and operating costs in the United States for 1999. Whereas some abatement options are unique to a specific segment of the natural gas system, many are applicable in multiple segments.

Production Abatement Options

The production segment of the natural gas sector consists of wells, compressors, dehydrators, pneumatic devices, chemical injection pumps, heaters, meters, pipeline, and central gathering facilities. Abatement technologies associated with the production segment include

- catalytic converters for select well field engines and compressors,
- replacement of wet seals with dry seals in centrifugal compressors,
- direct/enhanced inspection and maintenance at production sites,
- flash tank separator installation in glycol dehydration systems,
- replacement of high-bleed pneumatic devices, and
- optimization of glycol recirculation rates.

One example of technology available to the production segment reduces glycol recirculation rates. Producers use triethylene glycol (TEG) in dehydrators to remove water from the natural gas coming out of the ground to meet pipeline quality standards. "Dry" TEG is combined with natural gas to remove moisture content before the natural gas is sold into a pipeline. The "rich" TEG then enters a boiler, where the foreign substances are evaporated and emitted into the atmosphere and the cycle repeats itself. The rate at which this process occurs is directly proportional to the amount of CH_4 emitted from glycol dehydrators. Production fields become less productive over time, but the rate at which the TEG recirculates is commonly based on the initial rate of production. As the well site matures, the TEG circulation rate becomes oversized. Recirculation can be recalculated to achieve sufficient moisture removal from the gas and minimize the release of CH_4 from the system. The following are the cost components for this abatement option:

- **Capital Costs.** This abatement option requires minimal or no additional equipment. However, similar to inspection and maintenance programs, the option is labor intensive, with the calculations and circulation adjustments conducted by engineering staff.
- **Annual Costs.** Annual costs primarily include the labor required to calculate new optimal recirculation rates each year as the well site becomes less productive.
- **Cost Savings/Benefits.** More CH_4 is brought to market for sale.

Processing Abatement Options

The processing segment consists of gas plant facilities that incorporate the use of vessels, dehydrators, compressors, acid gas removal (AGR) units, heaters, and pneumatic devices. Abatement technologies associated with the processing segment include

- fuel gas retrofit for reciprocating compressors,
- replacement of wet seals with dry seals in centrifugal compressors,
- conversion of gas pneumatic controls to instrument air, and
- DI&M at gas processing plants.

One example of abatement technology available to the processing segment converts gas pneumatic controls to compressed instrument air systems. Processing plants use pneumatic control systems to monitor various gas and liquid levels. As part of their normal operations, these devices release or bleed CH_4 into the atmosphere. Processing plants can substitute compressed air for natural gas within pneumatic systems. The following are the cost components for this abatement option:

- **Capital Costs.** Capital costs include the purchase and installation of a compressor, dehydrator, and volume tank—the major components of the instrument air system. Depending on the size of the gas processing plant, capital costs are estimated to be between $4,500 and $35,000 for the required capital equipment.
- **Annual Costs.** Annual costs include the annual energy, materials, and labor required to operate and monitor the equipment used in the compressed instrument air system. Annual energy costs are determined by the size of the compressor. Annual servicing costs range from $800 to $3,600 per year.
- **Cost Savings/Benefits.** By replacing natural gas with compressed instrument air, CH_4 is no longer being vented during normal operations. The benefit is the market value of CH_4 abated.

Transmission Abatement Options

The transmission segment of a natural gas system consists of transmission pipeline networks, compressor stations, and meter and pressure-regulating stations. The following are abatement technologies available to the transmission segment:

- conversion of gas pneumatic controls to instrument air,
- use of pipeline pumpdown techniques to lower gas line pressure before maintenance,
- DI&M at compressor stations and surface facilities,
- replacement of wet seals with dry seals in centrifugal compressors, and
- replacement of compressor rod packing systems.

One example of the abatement options available to the transmissions segment is DI&M at compressor stations. Compressor stations amplify pressure at several stages along a transmission natural gas pipeline to combat pressure loss over long distances. Over time, compressors and other related components become fatigued and may leak CH_4. The DI&M program reduces CH_4 emissions at compressor stations by identifying leaks and focusing maintenance on the largest leaks. The following are the cost components for this abatement option:

- **Capital Costs.** Capital costs include the cost of purchasing a leak detection device, which varies widely depending on the type of device used. The cost of screening devices ranges from $1,000 to $20,000. The cost of more sensitive sampling devices ranges from $1,000 to $10,000.
- **Annual Costs.** Annual costs include the cost of labor and materials to develop a maintenance schedule and implement the survey and maintenance annually. Annual costs account for the majority of costs associated with implementing this abatement option.
- **Cost Savings/Benefits.** Cost savings are approximately $3 per thousand cubic feet (Mcf) of CH_4 recovered. The savings will depend on the intensity of the DI&M program and whether the leak, once detected, is fixed. The average station leak rate is approximately 41,000 Mcf per year, and the average annual cost savings is $88,000 at a gas price of $3 per Mcf (USEPA, 2003b).

Distribution Abatement Options

The distribution segment consists of main and service pipeline networks, meter and pressure-regulating stations, pneumatic devices, and customer meters. Abatement technologies available to the distribution segment include the

- use of hot taps in service pipeline connections,
- DI&M at gate stations,
- use of composite wrap for nonleaking pipeline defects, and
- use of a pipeline pumpdown technique to lower gas line pressure before maintenance.

An example abatement option available to the distribution segment is the use of a pipeline pumpdown technique when performing maintenance on segments of distribution pipeline. Operators routinely reduce line pressure and discharge gas from a pipeline during maintenance and repair activities. Using a pumpdown technique, which requires the use of inline and/or portable compressors to depressurize the section of pipeline, operators can mitigate CH_4 emissions. The following are the cost components for this abatement option:

- **Capital Costs.** Capital costs include the one-time costs of purchasing a portable compressor. The cost of this compressor varies by size and ranges from $500,000 (300 psi) to $3,000,000 (1,000 psi). Installation and freight costs are determined by the size of the compressor purchased.
- **Annual Costs.** Annual costs include fuel/energy, maintenance, and labor costs. Average energy costs vary based on the compressor's horsepower rating. Maintenance costs range from $4 to $9 per horsepower per month.
- **Cost Savings.** Cost savings will vary depending on the volume of gas available for recovery. The volume of gas available is determined by the length of pipeline to be repaired and the flow rate of gas during normal operations.

II.2.4 Results

This section presents the EMF-21 study's MAC results in tabular format.

II.2.4.1 Data Tables and Graphs

Table 2-10 presents the average breakeven price and the reduction in absolute and percentage terms for the mitigation options discussed in Section II.2.3.1.

The EMF regional baselines and MAC results of the EMF-21 study are presented in Tables 2-11 and 2-12 for 2010 and 2020 using a base energy price, a 10 percent discount rate, and a 40 percent tax rate. These MACs represent static percentage reductions in baselines for individual regions/countries and represent the official MACs used in climate change modeling. Figure 2-2 provides MACs for the five EMF countries/regions with the largest estimated emissions for natural gas systems in 2020.

The MACs presented in this section represent static abatement curves using breakeven prices built on the assumption of fixed mitigation cost and aggregate countrywide natural gas statistics. Appendix C to this chapter presents more recent efforts to develop an alternative framework for conducting MAC analysis that addresses the limitations of the EMF-21 MAC analysis.

Table 2-10: Natural Gas MACs for Countries Included in the Analysis

Technology	Breakeven Cost ($/t$CO_2$eq)	Emissions Reduction (% from baseline)	Emissions Reduction in 2010 (MtCO_2eq)	Emissions Reduction in 2020 (MtCO_2eq)
	Assuming a 10% discount rate and a 40% tax rate			
P&T—use gas turbines instead of reciprocating engines	$113.36	4%	0.21	0.27
P&T—compressors altering start-up procedure during maintenance	–$15.22	0%	0.01	0.01
Prod-D I&M (chemical inspection pumps)	$121.98	0%	0.01	0.01
Prod-D I&M (enhanced)	$836.05	0%	0.01	0.01
Prod-D I&M (offshore)	$49.51	0%	0.01	0.01
Prod-D I&M (onshore)	$682.60	0%	0.01	0.01
Prod-D I&M (pipeline leaks)	$55.82	1%	0.07	0.09
Installation of electric starters on compressors (production)	$9,829.72	0%	0.00	0.00
Installation of flash tank separators (production)	$85.47	2%	0.09	0.10
Installation of plunger lift systems in gas wells	$3,233.11	0%	0.00	0.00
Portable evacuation compressor for pipeline venting (production)	$178.89	0%	0.00	0.00
Reducing the glycol circulation rates in dehydrators (production)	–$25.03	0%	0.01	0.02
Replace high-bleed pneumatic devices with compressed air systems (production)	$85.36	5%	0.23	0.27
Replace high-bleed pneumatic devices with low-bleed pneumatic devices (production)	–$12.22	4%	0.20	0.23
Surge vessels for station/well venting (production)	$8,774.06	0%	0.00	0.00
Dry seals on centrifugal compressors (P&T)	$36.75	3%	0.16	0.20
Fuel gas retrofit for blowdown valve	–$26.67	2%	0.08	0.10
Reducing the glycol circulation rates in dehydrators (P&T)	–$27.55	0%	0.01	0.01
Catalytic converter (P&T)	$76.81	3%	0.16	0.20
P&T-D I&M (compressor stations)	–$25.24	0%	0.02	0.03
P&T-D I&M (compressor stations: enhanced)	–$24.45	0%	0.02	0.03
P&T-D I&M (enhanced: storage wells)	$100.27	0%	0.00	0.00
P&T-D I&M (pipeline: transmission)	$2,863.14	0%	0.00	0.00
P&T-D I&M (wells: storage)	$79.74	0%	0.00	0.00
Installation of flash tank separators (P&T)	$7.57	0%	0.01	0.01
Portable evacuation compressor for pipeline venting (P&T)	$178.89	2%	0.10	0.13
Static-pacs on reciprocating compressors (P&T)	$34.30	0%	0.01	0.02

(continued)

Table 2-10: Natural Gas MACs for Countries Included in the Analysis (continued)

Technology	Breakeven Cost ($/tCO$_2$eq)	Emissions Reduction (% from baseline)	Emissions Reduction in 2010 (MtCO$_2$eq)	Emissions Reduction in 2020 (MtCO$_2$eq)
Replace high-bleed pneumatic devices with compressed air systems (P&T)	$88.69	2%	0.09	0.11
Replace high-bleed pneumatic devices with low-bleed pneumatic devices (P&T)	–$12.22	2%	0.08	0.10
Surge vessels for station/well venting (P&T)	$8,774.06	1%	0.08	0.09
D-D I&M (distribution)	–$23.20	2%	0.12	0.15
D-D I&M (enhanced: distribution)	$21.02	4%	0.22	0.27
Electronic monitoring at large surface facilities (D)	$0.76	5%	0.27	0.33
Replacement of cast iron/unprotected steel pipeline (D)	$19,347.78	7%	0.34	0.42
Replacement of unprotected steel services (D)	$461,544.32	3%	0.14	0.17

Source: USEPA, 2003a. Adapted from Natural Gas Sector technology tables in Appendix B.
D = Distribution; I&M = Inspection and maintenance; P = Production; T = Transmission.

Table 2-11: Baseline Emissions by EMF Regional Grouping: 2000–2020 (MtCO$_2$eq)

Country/Region	2000	2010	2020
Africa	65.7	95.7	144.5
Annex I	**517.3**	**556.9**	**639.2**
Australia/New Zealand	6.1	9.6	15.2
Brazil	1.8	6.9	14.9
China	1.9	5.8	13.2
Eastern Europe	8.5	12.2	17.7
EU-15	25.2	25.4	26.4
India	15.8	35.7	61.4
Japan	0.4	0.4	0.4
Mexico	37.4	64.0	111.4
Non-OECD Annex I	**255.9**	**277.0**	**299.6**
OECD	**301.9**	**349.8**	**459.4**
Russian Federation	165.3	178.6	193.1
South & SE Asia	71.7	85.5	105.8
United States	145.7	138.6	164.8
World Total	**972.4**	**1,271.5**	**1,695.8**

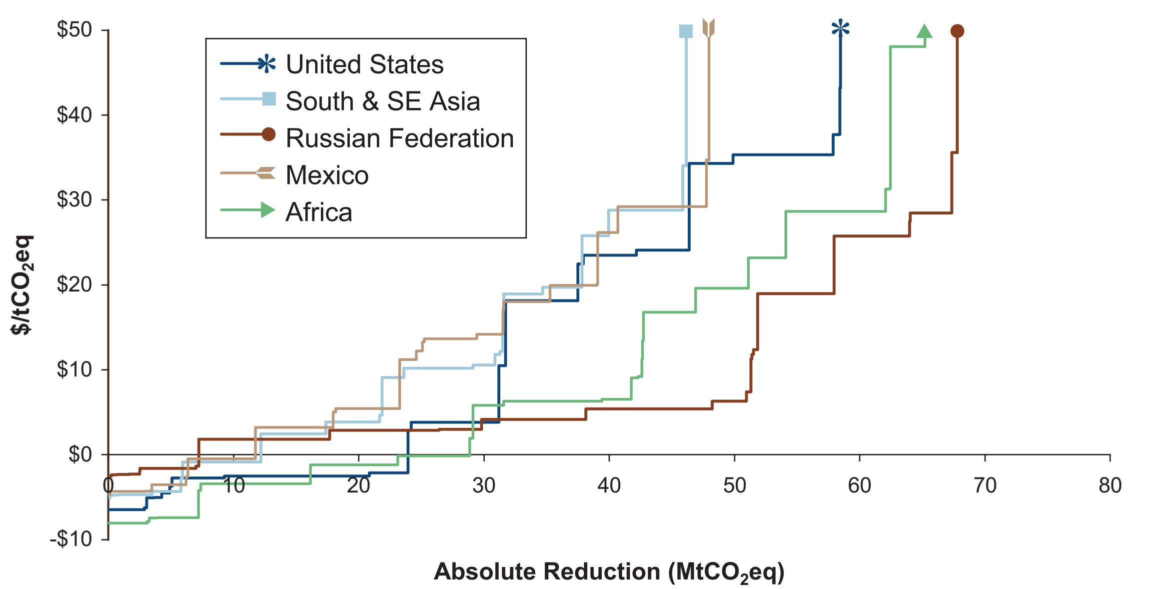
Source: USEPA, 2006.
EU-15 = European Union; OECD = Organisation for Economic Co-operation and Development.
Note: World Total does not equal the sum of the countries listed in this table because the regional groupings are a subset of the full EMF regional grouping list. See Appendix A of this report for the full EMF list of countries by region.

Table 2-12: Natural Gas MACs for Countries Included in the Analysis

	Percentage Reduction from Baseline (tCO_2eq)									
	2010					2020				
Country/Region	$0	$15	$30	$45	$60	$0	$15	$30	$45	$60
Africa	20.38%	29.98%	37.85%	43.62%	56.03%	20.38%	29.98%	37.85%	43.62%	56.03%
Annex I	**9.60%**	**24.21%**	**31.68%**	**35.12%**	**50.46%**	**8.98%**	**22.63%**	**29.62%**	**32.83%**	**47.18%**
Australia/New Zealand	14.44%	20.06%	29.35%	36.94%	56.54%	14.44%	20.06%	29.35%	36.94%	56.54%
Brazil	16.64%	25.42%	36.87%	43.54%	57.79%	16.64%	25.42%	36.87%	43.54%	57.79%
China	17.05%	36.78%	43.33%	44.11%	45.92%	17.05%	36.78%	43.33%	44.11%	45.92%
Eastern Europe	19.05%	25.84%	34.03%	34.22%	48.71%	19.05%	25.84%	34.03%	34.22%	48.71%
EU-15	11.58%	18.38%	28.39%	29.01%	49.18%	11.58%	18.38%	28.39%	29.01%	49.18%
India	10.70%	28.15%	36.44%	43.49%	58.74%	10.70%	28.15%	36.44%	43.49%	58.74%
Japan	28.05%	28.12%	32.51%	46.17%	61.10%	28.05%	28.12%	32.51%	46.17%	61.10%
Mexico	11.06%	23.15%	37.02%	43.55%	57.62%	11.06%	23.15%	37.02%	43.55%	57.62%
Non-OECD Annex I	**6.26%**	**27.29%**	**33.72%**	**35.50%**	**48.29%**	**6.09%**	**26.56%**	**32.81%**	**34.54%**	**46.99%**
OECD	**13.86%**	**20.73%**	**29.85%**	**35.60%**	**53.75%**	**12.14%**	**18.17%**	**26.16%**	**31.20%**	**47.11%**
Russian Federation	3.75%	26.85%	33.14%	35.11%	48.42%	3.75%	26.85%	33.14%	35.11%	48.42%
South & SE Asia	11.51%	29.75%	37.75%	43.61%	56.22%	11.51%	29.75%	37.75%	43.61%	56.22%
United States	14.52%	19.24%	28.14%	35.47%	54.76%	14.52%	19.24%	28.14%	35.47%	54.76%
World Total	**10.11%**	**24.98%**	**32.95%**	**37.90%**	**53.36%**	**10.19%**	**25.25%**	**33.24%**	**38.40%**	**53.81%**

Source: USEPA, 2003a.
EU-15 = European Union.

Figure 2-2: EMF MACs for Top Five Emitting Countries/Regions from Natural Gas: 2020



Source: USEPA, 2003a.
Note: This table was constructed using percentage reductions from USEPA (2003), with baselines from USEPA (2005).

II.2.5 Summary

The methodology and data discussed in this section describe the MAC analysis conducted for the natural gas sector by the EMF-21 study. MACs for 2010 and 2020 were estimated based on aggregated industry data from each country or region. The MACs represent static estimates of potential CH_4 mitigation from natural gas systems based on available information regarding infrastructure and country-reported emissions estimates provided through the United Nation's Framework Convention on Climate Change emissions inventory reports.

II.2.6 References

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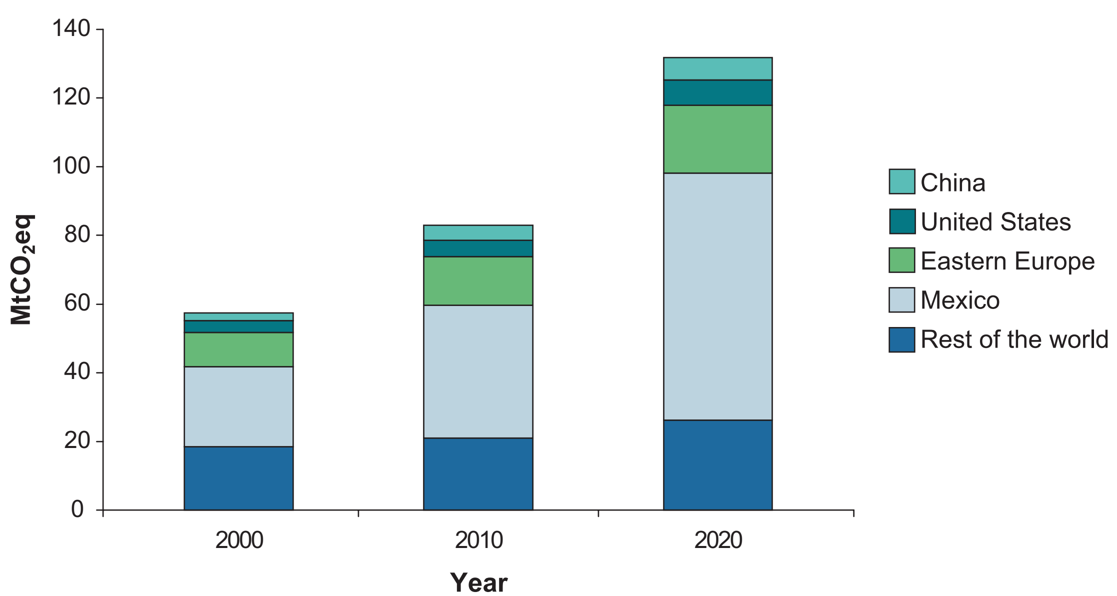
II.3 Oil Sector

Worldwide CH_4 emissions from oil production accounted for more than 57 $MtCO_2eq$ in 2000 (USEPA, 2006). Oil is the 11th largest source of anthropogenic CH_4 emissions globally. The USEPA estimates that oil production contributed approximately 0.5 percent of total global CH_4 emissions in 2000 (USEPA, 2006). Combined, Mexico, Eastern Europe, the United States, and China accounted for approximately 67 percent of the world's CH_4 emissions from oil (Figure 3-1). Global CH_4 emissions from oil are expected to grow by approximately 104 percent between 2005 and 2020.

Figure 3-1: CH_4 Emissions from Oil Production by Country: 2000–2020



Source: USEPA, 2006.

II.3.1 Introduction

Oil production begins by extracting crude oil either from underground production field wells (onshore) or platform oil derricks (offshore). The process of extracting oil involves drilling a deep well to access an oil reservoir underground. Once a well is drilled, compressors are used to pressurize the well, allowing the crude oil to exit the well through the vertical shaft. The compressed oil is transported via pipeline to a processing system and finally to a storage tank. Marine, rail, and truck tankers are the three major forms of transportation used by the oil sector to move crude oil from the site of production to the refinery. Pumping stations regulate the transfer of crude oil from storage tanks or pipelines onto transport tankers.

CH_4 emissions are associated with crude oil production, transportation, and refining operations. These oil production segments release CH_4 into the atmosphere as fugitive emissions, emissions from operational upsets, and emissions from fuel combustion (USEPA, 2004). In the United States, the largest emissions sources include high-bleed pneumatic devices, flaring, chemical injection pumps, and oil wellheads for light crude (USEPA, 2004). Emissions from oil production fields accounted for more than 97 percent of the total oil industry emissions. The remaining 3 percent was emitted from crude oil refinement (2 percent) and transportation (1 percent) (USEPA, 2004).

II.3.1.1 Emissions from Production Field Operations

During production field operations, CH_4 is released into the atmosphere via venting, accidental leaks, and fuel combustion. The USEPA suggests that the majority of emissions come from oil wellheads, storage tanks, and related field processing equipment such as compressors and chemical and injection pumps. CH_4 emissions from storage tanks, a dominant source of emissions, are created when the CH_4 entrained in crude oil under high pressure volatilizes as the oil enters the tank where it is stored at atmospheric pressure. Equipment leaks and vessel blowdowns during routine maintenance make up the second largest share of emissions from oil systems. The remaining emissions from field operations are associated with fugitive leaks and combustion through flares (USEPA, 2004).

Saudi Arabia and the United States were the two largest producers of oil in 2000, producing a reported 9.2 and 8.1 million barrels of crude oil per day, respectively. However, they do not have the largest CH_4 emissions from oil. Onshore production of oil generates less CH_4 emissions than offshore oil operations, because CH_4 produced onshore is more readily captured and transported for use. Oil production in many of the Organization of the Petroleum Exporting Countries (OPEC) members, including Saudi Arabia, consists primarily of onshore production operations. In contrast, a large share of the oil production in Mexico comes from offshore platforms.

II.3.1.2 Emissions from Crude Oil Transportation

Venting activities in transport tanks and marine vessel loading operations account for the majority of emissions in the transportation segment. Fugitive emissions from floating roof tanks account for the remainder of oil transportation emissions in the United States (USEPA, 2004).

II.3.1.3 Emissions from Crude Oil Refining

Most of the CH_4 entrained in crude oil has already escaped prior to the refining stage. Vented emissions that occur during normal operations account for the majority of emissions from this sector. Examples include refinery system blowdowns during routine maintenance and asphalt blowing. Fugitive leaks and combustion emissions are also a source of emissions. Most fugitive emissions come from leaks in a refinery's fuel gas system. Combustion emissions result from small amounts of unburned CH_4 in process heater stacks and from unburned CH_4 in engine exhausts and flares (USEPA, 2004).

II.3.1.4 Abatement Options

Three abatement options are discussed for the oil sector: flaring, direct use, and reinjection of gas into oil fields. The installation of a flaring system results in an estimated 98 percent reduction in fugitive emissions but can be costly in an offshore environment because of technical, environmental, and safety concerns. Direct use is applicable primarily to oil platforms, because CH_4 captured onshore is typically injected into the pipeline system (and is reflected in the baseline emissions). Reinjection of CH_4 back into the oil production field is an alternative to flaring or direct use and can enhance future oil recovery.

The following sections discuss the activity data and emissions factors used to develop baseline emissions, abatement options and their costs, and CH_4 MACs for oil production for selected countries. The chapter concludes with sensitivity analysis of key assumptions and a discussion of uncertainties and limitations.

II.3.2 Baseline Emissions Estimates

Baseline emissions from the oil sector are composed of emissions from production field operations, crude oil transportation, and crude oil refining. These emissions are classified either as fugitive emissions, vented emissions from operations, or emissions from fuel combustion (USEPA, 2004).

A country's baseline emissions estimate is the product of activity factors and emissions factors. The following section provides an overview of activity and emissions factors and concludes with a discussion of historical and projected baselines by type of equipment used.

II.3.2.1 Activity Factors

Activity factors characterize a given industry's size, either as the number of units (e.g., number of wells or miles of pipeline) or the flow through the units (million barrels [MMbbl] per day or year). The United States tracks 70 different activity factors for the oil industry. Some of these activity factors change annually in proportion to rates of crude oil production, transportation, and refinery runs, while others change in proportion to the number of facilities such as oil wells and petroleum refineries (USEPA, 2004). A detailed list of the activity factors related to production field operations, transportation, and refining is provided in Appendix D to this chapter (see Table D-1).

IPCC recognizes that this level of detailed information is not readily available in every country and therefore offers guidance on more aggregate activity factors that can be used to quantify the size of a country's oil system. Generally, aggregate activity factors such as production and consumption of oil are used.

Historical Activity Data

Oil production and consumption rates depend on economic conditions, global demand, and available reserves. For the purposes of this report, historical activity data were taken from publicly available reports, either from national communications or, when information was unavailable, from expert judgment (USEIA, 2005a). Table 3-1 reports oil production for selected countries in MMbbl per day for 1990 to 2003.

Projected Activity Data

Oil production is projected to increase by approximately 43 percent during the next 20 years. Table 3-2 and Table 3-3 list forecasted estimates for oil production and consumption between 2002 and 2025. In addition to OPEC countries continuing to expand production, Eastern European and some developing countries are forecasted to experience large proportional growth. Countries from the FSU in the Caspian Area are expected to experience the largest increase in production between 2002 and 2025, expanding from 1.66 to 6.22 MMbbl per day. Developing countries in regions such as Africa and the Middle East are also expected to expand production by 127 percent and 46 percent, respectively.

II.3.2.2 Emissions Factors and Related Assumptions

Emissions factors from oil production are defined as CH_4 emissions rates by either equipment type or operation. Equipment used in crude oil production includes wellheads, compressors, pipelines, storage tanks, and pneumatic devices. The United States has conducted a detailed bottom-up analysis to estimate average emissions factors by equipment or operation type. For countries or regions where this level of detail is unavailable, the IPCC's *1996 Revised Guidelines Reference Manuel* provides suggested approximate average emissions factors for each segment of oil systems for various regions around the world.

Table 3-1: Oil Production by Country: 1990–2003 (MMbbl per Day)

Country	1990	1995	2000	2002	2003
Saudi Arabia	7.0	9.2	9.5	8.8	10.1
United States	9.0	8.6	8.1	8.0	7.8
Russian Federation	N/A	6.2	6.7	7.7	8.5
Iran	3.1	3.7	3.8	3.5	3.8
Venezuela	2.3	3.0	3.4	2.9	2.6
Mexico	3.0	3.1	3.4	3.6	3.8
China	2.8	3.0	3.2	3.4	3.4
Norway	1.8	2.9	3.3	3.3	3.3
Canada	2.0	2.4	2.7	2.9	3.0
Iraq	2.1	0.6	2.6	2.0	1.3
United Arab Emirates	2.3	2.4	2.6	2.4	2.7
United Kingdom	1.9	2.8	2.5	2.5	2.3
Kuwait	1.2	2.2	2.2	2.0	2.3
Nigeria	1.8	2.0	2.2	2.1	2.2
Brazil	0.8	0.9	1.5	1.7	1.8
World Total	**65.5**	**68.9**	**75.9**	**75.0**	**77.7**

Source: USEIA, 2005a. Adapted from Table G-1 in the International Energy Annual 2003.

Historical Emissions Factors

Historical emissions factors have remained relatively constant. Countries use the IPCC's emissions factors cited in the *1996 Revised Guidelines* to estimate annual emissions baselines each year from publication of the *Guidelines* to the present. Table 3-4 lists aggregate emissions factors provided by the IPCC for petroleum system production, transportation, and refinement. These emissions factors are based on top-down estimates of emissions by industry segment. However, as mentioned earlier, the detailed bottom-up approach taken by the United States may enable a more accurate estimate of baseline emissions by country. The U.S. oil industry emissions factors (see Tables D-1, D-2, and D-3) are also assumed to remain constant in the short term (USEPA, 2004).

IPCC and the United States report higher emissions factors in the production segment than in any other segment of a petroleum system (IPCC, 1996; USEPA, 2004). In the United States, pneumatic devices used in production field operations, flares, chemical injection pumps, and offshore platforms have the highest emissions factors of any type of equipment or operation in the petroleum system.

Projected Emissions Factors

Projected emissions factors from oil are expected to follow historical trends. IPCC and the USEPA predict only slight changes in their estimated emissions factors for the next 20 years.[1] Although new technology for equipment and operating procedures may improve in the future, current emissions factors for equipment and operations will increase slightly because of equipment age and usage.

[1] Emissions estimates do not necessarily reflect the IPCC emissions factors presented in Table 3-2.

Table 3-2: Forecasted Oil Production for Selected Countries (MMbbl per Day, Unless Otherwise Noted)

Production	2002	2010	2015	2020	2025
Conventional[a]					
Industrialized Countries					
United States	9.3	9.9	9.7	9.5	9.3
Canada	2.1	1.8	1.7	1.6	1.6
Mexico	3.6	4.3	4.6	4.7	4.9
Western Europe[b]	6.9	6.4	6.0	5.6	5.0
Japan	0.2	0.1	0.1	0.1	0.1
Australia and New Zealand	0.8	1.0	0.9	0.9	0.9
Total industrialized	22.9	23.5	23	22.4	21.8
Transitional Economies					
FSU	11.2	13.6	15.3	16.4	17.5
Russian Federation	9.6	10.3	10.8	11.1	11.3
Caspian and other[c]	1.6	3.3	4.5	5.3	6.2
Eastern Europe[d]	0.2	0.3	0.4	0.4	0.5
Total transitional economies	11.4	13.9	15.7	16.8	18.0
Emerging Economies					
OPEC[e]					
Asia	1.4	1.6	1.5	1.5	1.5
Middle East	19.0	25.8	27.9	32.1	36.7
North Africa	3.0	3.6	3.9	4.4	4.6
West Africa	2.0	2.5	2.7	3.1	3.6
South America	2.9	3.5	4.0	4.4	5.0
Non-OPEC					
China	3.0	3.7	3.6	3.6	3.5
Other Asia	2.4	2.7	2.8	2.8	2.7
Middle East[f]	1.9	2.3	2.5	2.6	2.8
Africa	2.9	3.8	4.9	5.5	6.5
South and Central America	3.8	4.6	5.5	6.0	6.5
Total emerging economies	42.3	54.1	59.3	66.0	73.4
Total Production (Conventional)	**76.6**	**91.5**	**98.0**	**105.2**	**113.2**
Total Production (Unconventional)[g]	**1.5**	**2.8**	**4.9**	**5.5**	**5.7**
Total Production	**78.1**	**94.3**	**102.9**	**110.7**	**118.9**

Source: USEIA, 2005b. Adapted from the *International Energy Outlook 2004.* Table E4. World Oil Production by Region and Country, Reference Case, 1990–2025.

FSU = Former Soviet Union.

Note: Totals may not equal sum of components because of independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official USEIA data reports.

[a] Includes production of crude oil (including lease condensates), natural gas, plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol and other sources, and refinery gains.

[b] Includes Austria, Belgium, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Luxembourg, Macedonia, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, and the United Kingdom.

[c] Includes Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Krygyzstan, Latvia, Lithuania, Moldova, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.

[d] Includes Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Czech Republic, Hungary, Macedonia, Poland, Romania, Serbia Montenegro, Slovakia, and Slovenia.

[e] OPEC = Organization of Petroleum Exporting Countries. Includes Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

[f] Non-OPEC Middle East includes Bahrain, Cyprus, Israel, Jordan, Lebanon, Oman, Syria, Turkey, and Yemen.

[g] Includes liquids produced from energy crops, natural gas, coal, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.

Table 3-3: Forecasted Oil Consumption for Selected Countries (MMbbl per Day, Unless Otherwise Noted)

Consumption	2002	2010	2015	2020	2025
Mature Market Economies					
United States	19.7	22.5	24.2	25.8	27.3
Canada	2.1	2.3	2.5	2.5	2.6
Mexico	2.0	2.3	2.5	2.8	3.0
Western Europe	13.8	14.1	14.3	14.4	14.9
Japan	5.3	5.3	5.4	5.4	5.3
Australia/New Zealand	1.0	1.2	1.3	1.4	1.5
Total mature market economies	43.9	47.7	50.1	52.2	54.6
Transitional Economies					
FSU	4.1	4.7	4.9	5.2	5.5
Eastern Europe	1.4	1.6	1.8	1.9	2.1
Total transitional economies	5.5	6.3	6.7	7.2	7.6
Emerging Economies					
China	5.2	9.2	10.7	12.3	14.2
India	2.2	3.1	3.7	4.2	4.9
South Korea	2.2	2.6	2.8	2.9	2.9
Other Asia	5.6	7.9	9.2	10.4	11.6
Middle East	5.7	7.3	8.0	8.6	9.2
Africa	2.7	3.7	4.3	4.6	4.9
South and Central America	5.2	6.8	7.8	8.5	9.3
Total emerging economies	28.7	40.6	46.3	51.6	57.0
Total Consumption	**78.2**	**94.6**	**103.2**	**111.0**	**119.2**

Source: USEIA, 2005b. Adapted from the *International Energy Outlook 2004*. Table A4. World Oil Consumption by Region, Reference Case, 1990–2025.

FSU = Former Soviet Union.

Note: Totals may not equal sum of components because of independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official USEIA data reports.

Table 3-4: IPCC Emissions Factors for Petroleum Systems in Select Regions

	Petroleum System Industry Segments (kg/petajoule)				
	Production				
Region	Fugitive Emissions	Venting and Flaring	Transportation	Storage	Refining
Western Europe	300–5,000	1,000–3,000	745	90–1,400	20–250
United States and Canada[a]	300–5,000	3,000–14,000[a]	745	90–1,400	20–250
FSU, Central and Eastern Europe	300–5,000	—	745	90–1,400	20–250
Other oil-exporting countries	300–5,000	—	745	90–1,400	20–250
Rest of the world	300–5,000	—	745	90–1,400	20–250

Source: IPCC, 1996. Adapted from Table 1-58 in 1996 Revised Guidelines Reference Manual.

FSU = Former Soviet Union.

[a] In the United States and Canada, venting and flaring emissions are based on total production of both oil and gas produced.

II.3.2.3 Emissions Estimates and Related Assumptions

This section discusses the historical and projected baseline emissions from oil production.

Historical Emissions Estimates

Table 3-5 lists CH_4 emissions by country from 1990 through 2000. Historically, a country's emissions in the oil sector have correlated closely with oil production trends. Throughout the last decade, Mexico's oil emissions have grown to be the largest of any country. By 2000, Mexico had surpassed Romania, which experienced a sharp decline in baseline emissions over the same time period from 1990 through 2000.

Projected Emissions Estimates

As shown in Table 3-6, worldwide CH_4 emissions from oil are expected to increase by more than 80 percent from 2005 to 2020. Countries projected to experience increased production are also projected to have the largest growth in baseline emissions. Mexico and Brazil are projected to experience the largest increases at 160 percent and 157 percent, respectively, in their baseline emissions between 2005 and 2020.

II.3.3 The Cost of CH_4 Emissions Reductions from Oil

This section discusses opportunities for emissions reductions beyond existing baseline practices.

II.3.3.1 Abatement Option Opportunities

Three abatement options can be applied to the oil sector: flaring, direct use, and reinjection of gas into oil fields for enhanced oil recovery. Table 3-7 summarizes the costs and emissions reductions associated with each option.

Flaring in Place of Venting: Offshore and Onshore

The installation of a flaring system results in an estimated 98 percent reduction in fugitive emissions. Implementation of a flare in an offshore environment is more expensive because of technical, environmental, and safety concerns. For offshore application, total capital costs are estimated to be approximately $818 per tCO_2eq, and O&M costs are estimated to be approximately $25 per tCO_2eq. This abatement option has a technical lifetime of 15 years, yielding a breakeven price of approximately $177per tCO_2eq. For onshore sites, total capital costs are $34 per tCO_2eq, and annual O&M costs are approximately $1.10 per tCO_2eq, yielding a breakeven price of $7 per tCO_2eq. Capital costs are assumed to be constant across countries, but O&M costs vary because of differences in labor costs across countries. This option has no monetary benefits because the CH_4 is combusted and vented as CO_2 to the atmosphere.

Direct Use of CH_4

This abatement option applies primarily to offshore platforms and has an estimated reduction efficiency of 90 percent. In this abatement option, CH_4 is used for consumption on oil platforms and/or converted to liquefied natural gas. A 15-year lifetime is estimated for this abatement option. Total capital costs for this abatement option are approximately $55 per tCO_2eq. In the United States, O&M costs are estimated at $1.10 per tCO_2eq (O&M cost varies by country). Benefits for this abatement option are the cost savings from substituting CH_4 for alternative energy sources. For the United States, the breakeven price for direct use of CH_4 is $7 per tCO_2eq.

Table 3-5: Baseline Emissions from Oil Production, by Country: 1990–2000 ($MtCO_2eq$)

Country	1990	1995	2000
Mexico	18.8	19.3	23.3
Romania	20.1	11.4	8.3
China	1.2	1.4	2.2
United States	4.4	4.1	3.9
Nigeria	0.9	1.0	1.8
Iran	1.3	1.6	1.2
Kuwait	0.4	0.8	1.0
United Arab Emirates	1.1	1.2	1.2
Indonesia	1.2	1.0	1.9
Iraq	1.1	0.3	0.9
Ecuador	0.3	0.3	0.5
Canada	0.8	0.8	0.9
Bulgaria	0.6	0.7	0.6
Russian Federation	1.7	0.9	0.6
Lithuania	0.5	0.5	0.4
Rest of the world	**8.2**	**8.2**	**8.7**
World Total	**62.6**	**53.5**	**57.4**

Source: USEPA, 2006.

Table 3-6: Projected Baseline Emissions from Oil Production by Country: 2005–2020 ($MtCO_2eq$)

Country	2005	2010	2015	2020
Mexico	27.7	38.7	54.1	71.9
Romania	9.3	12.0	14.7	17.3
China	2.9	4.4	6.1	6.5
United States	3.4	3.7	4.1	4.5
Nigeria	2.2	2.7	3.3	4.1
Iran	1.8	2.2	2.7	3.6
Kuwait	1.0	1.3	1.4	1.8
United Arab Emirates	1.2	1.2	1.4	1.7
Indonesia	1.9	1.8	1.6	1.4
Iraq	0.8	0.9	1.0	1.3
Ecuador	0.6	0.6	0.8	1.1
Canada	0.9	0.9	1.0	1.0
Bulgaria	0.7	0.8	0.9	1.0
Russian Federation	0.7	0.8	0.9	1.0
Lithuania	0.6	0.6	0.7	0.8
Rest of the world	**9.1**	**10.1**	**11.4**	**12.9**
World Total	**64.7**	**82.9**	**106.1**	**131.8**

Source: USEPA, 2006.

Table 3-7: Cost of Reducing CH_4 Emissions from Oil

Abatement Technology	Year	Capital Cost ($/$tCO_2$eq)	Annual Cost ($/$tCO_2$eq)	U.S. Emissions Available for Reduction ($MtCO_2$eq)[a]	Reduction Efficiency	U.S. Emissions Reductions ($MtCO_2$eq)	Breakeven Price ($/$tCO_2$eq)[b]
Flaring: offshore							
	2010	832.60	24.91	0.52	98%	0.51	$170.35
	2020	832.60	24.91	0.53	98%	0.52	$170.35
Flaring: onshore							
	2010	33.30	0.99	0.52	98%	0.51	$6.82
	2020	33.30	0.99	0.53	98%	0.52	$6.82
Direct use (offshore)							
	2010	55.51	1.11	0.52	90%	0.47	$7.09
	2020	55.51	1.11	0.53	90%	0.48	$7.09
Reinjection (onshore)							
	2010	66.61	2.21	0.52	95%	0.49	$10.14
	2020	66.61	2.21	0.53	95%	0.50	$10.14

[a] Based on 50 percent of CH_4 emissions generated onshore and 50 percent offshore (USEPA, 2003).

[b] Based on 15-year lifetime.

Reinjection of CH_4

Reinjection of CH_4 is an alternative to flaring or direct use. In this option, CH_4 captured from oil field operations is reinjected into the oil production field to enhance future oil recovery. Reinjection has an estimated reduction efficiency of 95 percent and a technical lifetime of 15 years. Total capital costs for this technology are approximately $67 per tCO_2eq. Annual O&M costs are estimated to be $2.20 per tCO_2eq in the United States, but vary by country. Benefits associated with this option include an additional increase in oil recovery and the mitigation of costs associated with flaring. The estimated breakeven price for the United States is $10 per tCO_2eq.

II.3.4 Results

This section presents the EMF-21 study's MAC results in tabular format and provides a graph of the MACs for regions with the largest emissions.

II.3.4.1 Data Tables and Graphs

Percentages reported in Table 3-8 are from the report to the EMF provided by the USEPA (USEPA, 2003). It is estimated that there are no "no-regret" options for CH_4 abatement in the oil sector.

At a breakeven price of $23 per tCO_2eq, the average percentage abatement is 17 percent for the United States and 38 percent for China, reflecting the high cost of offshore options. Technology changes have not been incorporated into abatement potential for CH_4 from the oil sector.

Table 3-8: Percentage Abatement for CH_4 for Selected Breakeven Price ($/$tCO_2$eq): 2000

Technology	Breakeven Cost ($/$tCO_2$eq)	Emissions Reduction (% from Baseline)	Emissions Reduction in 2010 ($MtCO_2$eq)	Emissions Reduction in 2020 ($MtCO_2$eq)
	Assuming a 10% discount rate and 40% tax rate			
Flaring instead of venting (offshore)	$575.81	6%	0.02	0.03
Flaring instead of venting (onshore)	$23.03	3%	0.01	0.01
Direct use	$22.22	13%	0.05	0.06
Reinjection	$31.22	8%	0.03	0.04

Source: USEPA, 2003. Adapted from Oil Sector technology tables in Appendix B to EMF report.

The EMF regional baselines and MAC results of the EMF-21 study are presented in Tables 3-9 and 3-10 for 2010 and 2020 using the base energy price, a 10 percent discount rate, and a 40 percent tax rate. These MACs represent static percentage reductions in baselines for individual regions/countries and represent the official MACs used in climate change modeling. Figure 3-2 provides MACs for the five EMF countries/regions with the largest estimated emissions from the oil sector in 2020.

Table 3-9: Baseline Emissions by EMF Regional Grouping: 2000–2020 ($MtCO_2$eq)

Country/Region	2000	2010	2020
Africa	3.4	4.7	7.4
Annex I	**17.6**	**21.9**	**28.8**
Australia/New Zealand	0.1	0.2	0.3
Brazil	0.3	0.3	0.5
China	2.2	4.4	6.5
Eastern Europe	10.0	14.1	19.7
EU-15	1.0	1.0	1.1
India	0.2	0.3	0.4
Japan	0.0	0.0	0.0
Mexico	23.3	38.7	71.9
Non-OECD Annex I	**10.9**	**15.3**	**21.1**
OECD	**30.1**	**45.5**	**79.8**
Russian Federation	0.6	0.8	1.0
South & SE Asia	2.5	2.5	2.3
United States	3.9	3.7	4.5
World Total	**57.4**	**82.9**	**131.8**

Source: USEPA, 2006.

EU-15 = European Union; OECD = Organisation for Economic Co-operation and Development.

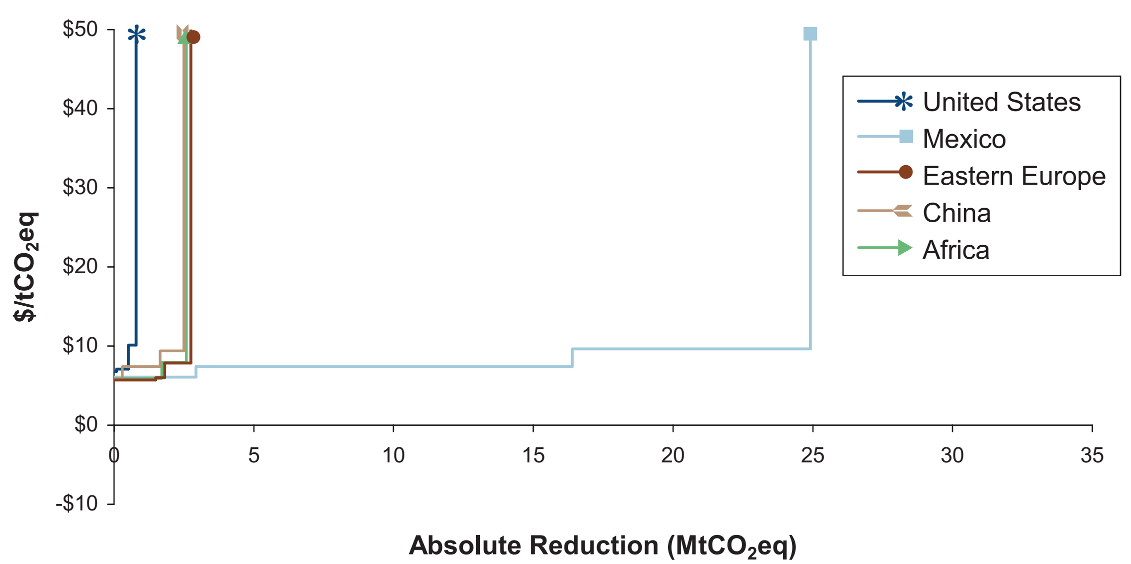
Note: World Total does not equal the sum of the countries listed in this table because the regional groupings are a subset of the full EMF regional grouping list. See Appendix A of this report for the full EMF list of countries by region.

Table 3-10: Oil System MACs for Countries Included in the Analysis

Country/Region	Percentage Reduction from Baseline (tCO_2eq)									
	2010					2020				
	$0	$15	$30	$45	$60	$0	$15	$30	$45	$60
Africa	0.00%	37.27%	37.27%	37.27%	46.05%	0.00%	37.27%	37.27%	37.27%	46.05%
Annex I	**0.00%**	**21.48%**	**21.48%**	**21.48%**	**26.54%**	**0.00%**	**20.16%**	**20.16%**	**20.16%**	**24.91%**
Australia/New Zealand	0.00%	22.07%	22.07%	22.07%	27.26%	0.00%	22.07%	22.07%	22.07%	27.26%
Brazil	0.00%	26.69%	26.69%	26.69%	32.97%	0.00%	26.69%	26.69%	26.69%	32.97%
China	0.00%	38.17%	38.17%	38.17%	47.15%	0.00%	38.17%	38.17%	38.17%	47.15%
Eastern Europe	0.00%	13.12%	13.12%	13.12%	16.20%	0.00%	13.12%	13.12%	13.12%	16.20%
EU-15	0.00%	11.71%	11.71%	11.71%	14.47%	0.00%	11.71%	11.71%	11.71%	14.47%
India	0.00%	17.54%	17.54%	17.54%	21.66%	0.00%	17.54%	17.54%	17.54%	21.66%
Japan	0.12%	0.22%	0.22%	0.22%	0.27%	0.12%	0.22%	0.22%	0.22%	0.27%
Mexico	0.00%	34.64%	34.64%	34.64%	42.79%	0.00%	34.64%	34.64%	34.64%	42.79%
Non-OECD Annex I	**0.00%**	**31.67%**	**31.67%**	**31.67%**	**39.12%**	**0.00%**	**30.81%**	**30.81%**	**30.81%**	**38.06%**
OECD	**0.00%**	**24.55%**	**24.55%**	**24.55%**	**30.33%**	**0.00%**	**22.75%**	**22.75%**	**22.75%**	**28.11%**
Russian Federation	0.00%	33.98%	33.98%	33.98%	41.97%	0.00%	33.98%	33.98%	33.98%	41.97%
South & SE Asia	0.00%	24.07%	24.07%	24.07%	29.73%	0.00%	24.07%	24.07%	24.07%	29.73%
United States	0.00%	17.67%	17.67%	17.67%	21.83%	0.00%	17.67%	17.67%	17.67%	21.83%
World Total	**0.00%**	**28.08%**	**28.08%**	**28.08%**	**34.69%**	**0.00%**	**28.96%**	**28.96%**	**28.96%**	**35.78%**

Source: USEPA, 2003.
EU-15 = European Union; OECD = Organisation for Economic Co-operation and Development.

Figure 3-2: EMF MACs for Top Five Emitting Countries/Regions from Oil: 2020



Source: USEPA, 2003.
Note: Regional MACs were constructed using percentage reductions from USEPA (2003), with baselines from USEPA (2005).

II.3.5 Uncertainties and Limitations

Uncertainties and limitations persist despite attempts to incorporate all publicly available international oil sector information. Limited information on the oil systems of developing countries increases this uncertainty. Additional information would improve the accuracy of baseline emissions projections:

- **Improved Cost Data.** Improved documentation of oil CH_4 abatement options and their cost components would make it easier to estimate baseline reductions, given some estimate of market penetration.
- **Improved Emissions Factor Data.** Improved documentation of emissions factors for oil systems of countries outside the United States would enhance the accuracy of international analysis of CH_4 emissions.
- **Improved Abatement Option Data.** Improved abatement option data are needed to identify true abatement opportunities for oil systems. For example, although flares have long been thought of as a potential abatement option, new research suggests that some amount of CH_4 may be escaping combustion at the site of the flare. Accurate information on emissions factors is necessary before reduction efficiencies can be estimated.

II.3.6 Summary

The data discussed in this chapter demonstrate that oil is a significant source of greenhouse gas emissions, but because of information limitations for some countries, a more thorough cost analysis is not possible. Self-regulation by industry and changes in market structure may lead to reductions in emissions baselines in the future. However, to truly understand the potential benefits of an abatement option in an oil system and to estimate potential market penetration across countries, more information is needed.

II.3.7 References

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Section II: Energy Sector Appendixes

Appendixes for this section are available for download from the USEPA's Web site at http://www.epa.gov/nonco2/econ-inv/international.html.