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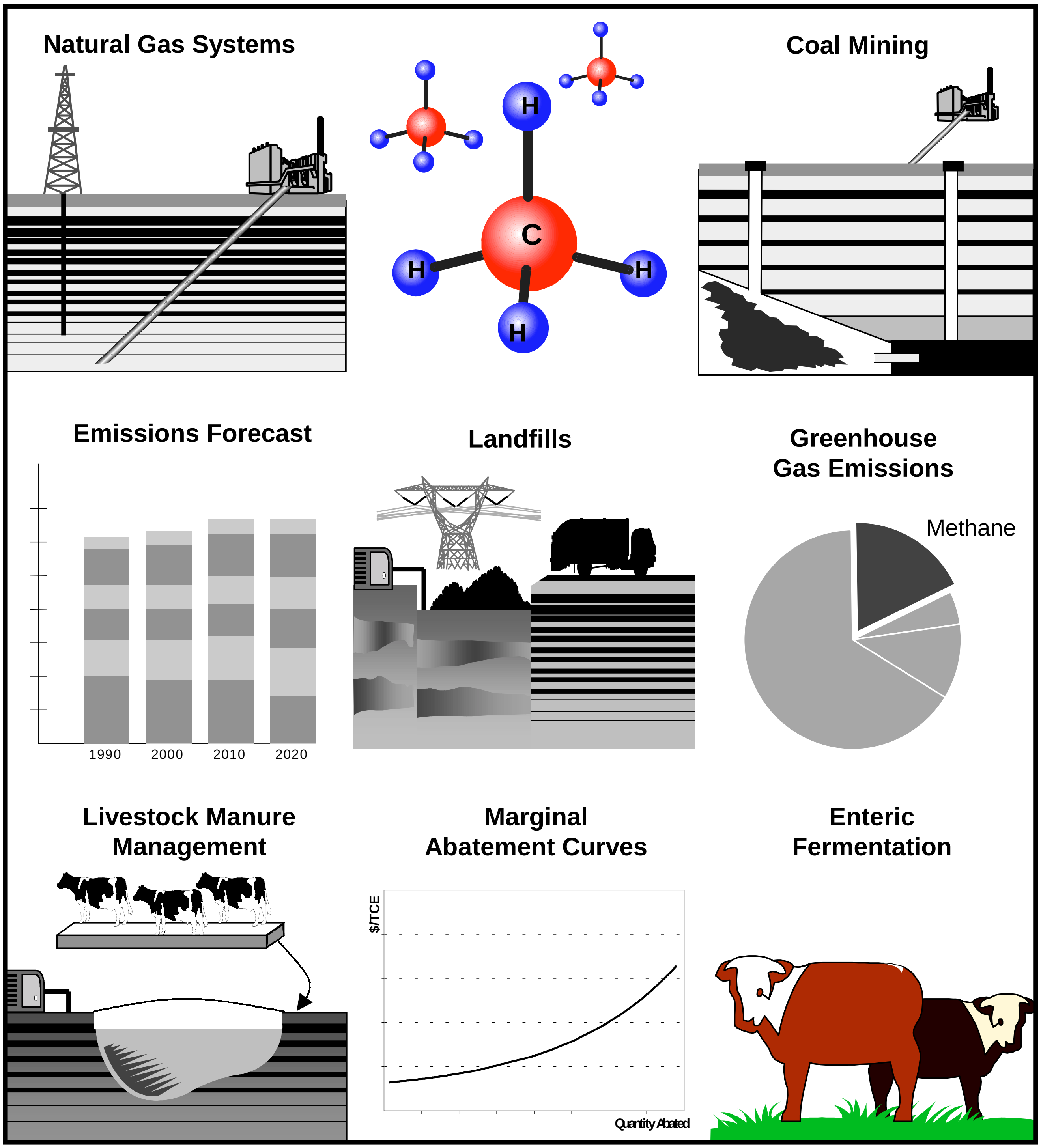
U.S. Methane Emissions 1990 – 2020: Inventories, Projections, and Opportunities for Reductions



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For Further Information

The results presented in this report are available to analysts in an electronic format. For additional information, contact Mr. Francisco de la Chesnaye, Office of Air and Radiation, Office of Atmospheric Programs, Climate Protection Division, Methane Energy Branch, Tel +1(202) 564 – 0172, Fax +1(202) 565 – 2077, or e-mail delachesnaye.francisco@epa.gov.

U.S. Methane Emissions 1990-2020: Inventories, Projections, and Opportunities for Reductions

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U.S. Environmental Protection Agency
Office of Air and Radiation
401 M St., SW
Washington, DC 20460
U.S.A.

Abbreviations, Acronyms, and Units

AF	Activity factor
ASAE	American Society of Agricultural Engineers
Bcf	Billion cubic feet
BMP	Best management practice
CAA	Clean Air Act
CCAP	Climate Change Action Plan
C&D	Construction and demolition
CFC	Chlorofluorocarbon
CH_4	Methane
CMOP	Coalbed Methane Outreach Program
CO_2	Carbon dioxide
DI&M	Directed inspection and maintenance
DOE	Department of Energy
EF	Emission factor
EIA	Energy Information Administration
EPA	Environmental Protection Agency
E-PLUS	Energy Project Landfill Gas Utilization Software
GAA	Government Advisory Associates
GHG	Greenhouse gas
GSAM	Gas Systems Analysis Model
GWP	Global warming potential
IC	Internal combustion
IPCC	Intergovernmental Panel on Climate Change
kW	kilowatt
kWh	kilowatt-hour
LMOP	Landfill Methane Outreach Program
MAC	Marginal abatement curve
Mcf	Thousand cubic feet
MMBtu	Million British thermal units
MMcf/d	Million cubic feet per day
MMTCE	Million (metric) tons of carbon equivalent
MMT	Million (metric) tons
MSHA	Mine Safety and Health Administration
MSW	Municipal solid waste
MW	Megawatt
NMOC	Non-methane organic compound
NPV	Net present value
O&M	Operation and maintenance
PRO	Partner-reported opportunity
RLEP	Ruminant Livestock Efficiency Program
Tcf	Trillion cubic feet
Tg	Teragram
TCE	Metric ton of carbon equivalent
UNFCCC	United Nations Framework Convention on Climate Change
USDA	United States Department of Agriculture
VOC	Volatile organic compound
WIP	Waste-in-place

Conversions

1 Mcf Methane = 1 MMBtu
1 Bcf = 1,000 MMcf
1 Tg = 1×10^{12} g
1 Tg CH_4 = 1 MMT CH_4
1 MMT CH_4 = 5.73 MMTCE
GWP of CO_2 = 1
GWP of CH_4 = 21

Acknowledgements

This report was produced by the U.S. EPA's Methane Energy Branch in the Office of Air and Radiation, Office of Atmospheric Programs, Climate Protection Division. The report would not have been complete without the efforts and contributions of many individuals and organizations. The following individuals reviewed a preliminary version of this report and provided useful comments, many of which were addressed for this final version. The reviewers included: Peter Carothers (Alternative Energy Development), Tom Conrad (SCS Engineers), Kimberly Denbow (American Gas Association), Lorna Greening (Hagler Bailly Services, Inc.), Matthew R. Harrison (Radian International), William Jewell (Cornell University), Barry L. Kintzer (USDA), Eugene Lee (USEPA), Bob Lott (Gas Research Institute), Richard Mattocks (Environomics), John Reilly (Massachusetts Institute of Technology), Glenda E. Smith (American Petroleum Institute), Pramod C. Thakur (Consol Inc.), Lori Traweek (American Gas Association), Greg Vogt (SCS Engineers), Ann C. Wilkie (University of Florida), and Peter Wright (Cornell University). Although these individuals participated in the review of this analysis, their efforts do not necessarily constitute an endorsement of the report's results or of any U.S. EPA policies and programs.

In particular, the Methane Energy Branch staff contributed significantly to the report. They are: Ed Coe, Shelley Cohen, and Brian Guzzone on Landfills; Paul Gunning and Carolyn Henderson on Natural Gas Systems; Karl Schultz and Roger Fernandez on Coal Mining; Kurt Roos on Livestock Manure; Mark Orlic and Tom Wirth on Enteric Fermentation; Bill Irving on Inventories; and Michele Dastin-van Rijn on the preliminary version of the report. Francisco de la Chesnaye directed the final analysis and completion of the report with support from Reid Harvey and oversight from Dina Kruger.

The staff of the Global Environmental Issues Group at ICF Consulting deserves special recognition for its expertise, efforts in preparing many of the individual analyses, and for synthesizing this report.

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Executive Summary

Methane gas is a valuable energy resource and the leading anthropogenic contributor to global warming after carbon dioxide. Atmospheric methane concentrations have doubled over the last 200 years and continue to rise, although the rate of increase is slowing (Dlugokencky, et al., 1998). By mass, methane has 21 times the global warming potential of carbon dioxide over a 100-year time frame. Methane accounts for 10 percent of U.S. greenhouse gas emissions (excluding sinks) and reducing these emissions is a key goal of the U.S. Climate Change Action Plan (EPA, 1999).

The major sources of anthropogenic methane emissions in the U.S. are landfills, agriculture (livestock enteric fermentation and manure management), natural gas and oil systems, and coal mines. Smaller sources in the U.S. include rice cultivation, wastewater treatment, and others. Unlike other greenhouse gases, methane can be used to produce energy since it is the major component (95 percent) of natural gas. Consequently, for many methane sources, opportunities exist to reduce emissions cost-effectively or at low cost by capturing the methane and using it as fuel.

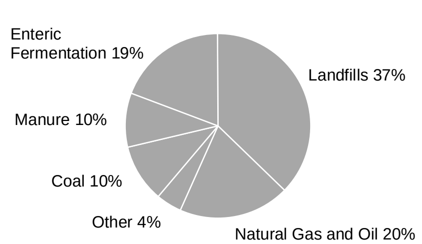
This report has two objectives. First, it presents the U.S. Environmental Protection Agency's (EPA's) baseline forecast of methane emissions from the major anthropogenic sources in the U.S., and EPA's cost estimates of reducing these emissions. Emission estimates are given for 1990 through 1997 with projections for 2000 to 2020. The cost analysis is for 2000, 2010, and 2020. Second, this report provides a transparent methodology for the calculation of emission estimates and reduction costs, thereby enabling analysts to replicate these results or use the approaches described herein to conduct similar analyses for other countries.

Baseline Methane Emission Estimates

EPA estimates annual emissions for 1990 to 1997 and forecasts emissions for 2000, 2010, and 2020. In 1990, the U.S. emitted 169.9 million metric tons of carbon equivalent (MMTCE) or 29.7 Teragrams (Tg) of methane. By 1997, estimated methane emissions were slightly higher at 179.6 MMTCE (31.4 Tg) (EPA, 1999). The baseline U.S. methane emission forecast for 2010 is 186.0 MMTCE (32.5 Tg) which is almost a ten percent increase over the 1990 levels. However, this forecast excludes the expected reductions associated with U.S. voluntary programs. When these programs are taken into account, methane emissions are expected to remain at or below 1990 levels through 2020. Exhibit ES-1 shows current methane emissions and projections by industry.

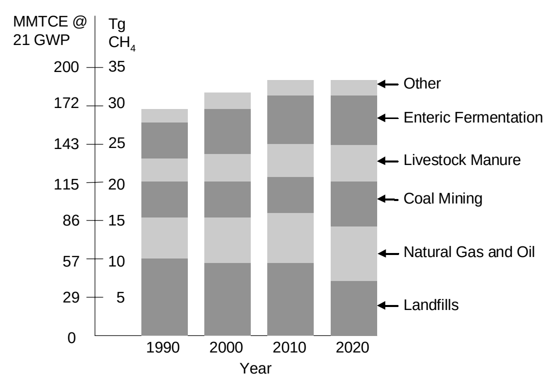
Exhibit ES-1: U.S. Methane Emissions (MMTCE)

Source Breakdown of 1997 U.S. Methane Emissions



Total = 179.6 MMTCE
Source: EPA, 1999.

Source Breakdown of Baseline Forecast Emissions



To estimate historic and future emissions, EPA characterizes the source industries in detail and identifies the specific processes within those industries that produce emissions. Forecasts are based on a consistent set of industry factors, e.g., consumption, prices, technological change, and infrastructure makeup. The major emission sources are outlined below.

- **Landfills.** The largest source (accounting for 37 percent) of U.S. anthropogenic methane emissions, landfills generate methane during anaerobic decomposition of organic waste. In 1990, landfills generated 56.2 MMTCE (9.8 Tg) of methane, which increased to 66.7 MMTCE (11.6 Tg) by 1997 (EPA, 1999). Baseline emissions are expected to decrease to 52.0 MMTCE (9.1 Tg) in 2010, due to the Clean Air Act New Source Performance Standards and Emissions Guidelines (Landfill Rule). The Landfill Rule requires the nation's largest landfills to reduce emissions of non-methane organic compounds and results in a simultaneous reduction in methane emissions. The principal technologies for reducing emissions from landfills involve collecting methane and using it as fuel for electric power generation or for sale to nearby industrial users.

- **Natural Gas Systems.** Emissions of methane occur throughout the natural gas system from leaks and venting of gas during normal operations, maintenance, and system upsets. In 1990, methane emissions from the U.S. natural gas system totaled about 32.9 MMTCE (5.7 Tg), and by 1997 methane emissions were estimated at 33.5 MMTCE (5.8 Tg) (EPA, 1999). EPA expects emissions to increase as natural gas consumption increases, although at a lower rate than gas consumption growth. Baseline emissions reach 37.9 MMTCE (6.6 Tg) in 2010. Improved management practices and technologies can reduce leaks or avoid venting of methane from all parts of the natural gas system.

- **Coal Mining.** Methane and coal are formed together by geological forces during coalification. As coal is mined, the methane is released. Because methane is hazardous to miners, underground mines use ventilation systems to dilute it and additional techniques to recover it during or in advance of mining. In 1990, coal mine methane emissions were estimated at 24.0 MMTCE (4.2 Tg). By 1997, emissions fell to 18.8 MMTCE (3.3 Tg) mainly due to reduced coal production at "gassy" mines and increased methane recovery (EPA, 1999). Baseline methane emissions reach 28.0 MMTCE (4.9 Tg) by 2010 due to growth in coal mining from deep mines. The major technologies for reducing emissions include recovery and sale to pipelines, use for power generation, or on-site use. Catalytic oxidation of methane in ventilation air may also be undertaken to reduce emissions.

- **Livestock Manure Management.** Methane is produced during the anaerobic decomposition of livestock manure. The major sources of U.S. livestock manure methane include large dairy and cattle operations and hog farms that use liquid manure management systems. In 1990, livestock manure emitted about 14.9 MMTCE (2.6 Tg) of methane. Emissions from this source increased to 17.0 MMTCE (3.0 Tg) by 1997 (EPA, 1999). Baseline emissions reach 22.3 MMTCE (3.9 Tg) in 2010 due to animal population growth driven by increases in total meat and dairy product consumption and increasing use of liquid waste management systems that produce methane. Existing cost-effective technologies can be used to recover this methane to produce energy.

- **Enteric Fermentation.** Methane emissions from livestock enteric fermentation were 32.7 MMTCE (5.7 Tg) in 1990 and 34.1 MMTCE (6.0 Tg) in 1997 (EPA, 1999). Baseline methane emissions reach 37.7 MMTCE (6.6 Tg) by 2020 due to increased domestic and international demand for U.S. livestock products. Emissions can be reduced through the application of improved management practices. The cost-effectiveness of these practices has not been quantified as part of this analysis, however.

Costs of Reducing Emissions

This report presents the results of extensive benefit-cost analyses conducted on the opportunities (technologies and management practices) to reduce methane emissions from four of the five major U.S. sources: landfills, natural gas systems, coal mining, and livestock manure. To date, most economic analyses of U.S. greenhouse gas (GHG) emission reductions have focused on energy-related carbon emissions since carbon dioxide (CO_2) currently accounts for about 82 percent of the total U.S. GHG emissions (weighted by 100-year global warming potentials) (EPA, 1999). The cost estimates for reducing methane emissions presented in this report can be integrated into economic analyses to produce more comprehensive assessments of total GHG reductions. By including methane emission reductions, the overall cost of reducing GHG emissions in the U.S. is reduced. At increasing values for emission reductions, in terms of dollars per metric ton of carbon equivalent ($/TCE), more costly CO_2 reductions can be substituted by lower cost methane reductions, when available, thereby lowering the marginal cost and the total cost of a particular GHG emission reduction level.

The cost analysis is conducted for the years 2000, 2010, and 2020. All values are in 1996 constant dollars. Results for the source-specific analyses are summarized below.

- **Landfills.** The cost analysis focuses on technologies for recovering and using landfill methane for energy. Two options are evaluated: use of landfill methane for electricity generation and as a fuel for direct use by a nearby end-user. After accounting for emission reductions due to the Landfill Rule, at $0/TCE, about 21 percent of baseline emissions from landfills could be captured and used cost-effectively in 2000. Cost-effective reductions decrease slightly to 20 percent, at $0/TCE, in 2010, in part reflecting greater coverage of total emissions by the Landfill Rule. At $30/TCE, emissions could be reduced by 38 percent from the baseline in 2000, and by 41 percent in 2010. Emission reductions approach their maximum at $100/TCE in 2000, and $40/TCE in 2010. EPA projects the incremental benefits of higher values for carbon equivalent to be slightly smaller in 2020 due to the Landfill Rule.
- **Natural Gas Systems.** Cost curves for reducing methane emissions from natural gas systems are based on technologies and practices for reducing leaks and venting of natural gas in the natural gas system. EPA evaluates 118 technologies and practices that have been identified by the gas industry in conjunction with EPA's Natural Gas STAR Program. EPA's analysis assesses the cost-effectiveness of each technology and practice based on the value of methane as natural gas. In 2000, 2010, and 2020, about 30 percent of the projected emissions from natural gas systems can be avoided cost-effectively, based on the value of the saved methane. When a value of $30/TCE for avoided emissions is added to the market price for gas, about 35 percent of the emissions can be reduced. At $100/TCE, about 49 percent of emissions can be reduced. Additional technologies could likely emerge in this sector to reduce emissions at high values for carbon equivalent, however, EPA only examines current technologies in this analysis.
- **Coal Mining.** EPA's analysis for reducing coal mine methane emissions focuses on recovering methane from underground mining, which comprises 65 percent of the emissions from this source. Two emission reduction strategies are analyzed: recovering methane from mines for sale as natural gas and using new catalytic oxidation technologies. The results suggest that in 2010, 37 percent of emissions from coal mines can be cost-effectively reduced at energy market prices, or $0/TCE. Up to 71 percent of emissions can be reduced at $30/TCE, which represents essentially all of the technically recoverable methane from this source. In 2020, the same pattern exists with 41 percent recoverable at $0/TCE and 71 percent recoverable at $30/TCE.
- **Livestock Manure Management.** Cost curves for reducing methane emissions from livestock manure are based on recovering and utilizing

methane produced at dairies and swine farms. EPA's analysis focuses on anaerobic digestion technologies (including covered and complete mix digesters) that capture methane for use on-site to generate electricity. At current energy prices, emissions from livestock manure could be reduced by 14 percent in 2000 and 2010. Emission reductions increase slightly to 15 percent in 2020. With an additional $30/TCE, emission reductions reach 30 percent in 2000, 31 percent in 2010, and 32 percent in 2020. At $100/TCE, emissions can be reduced by about 63 percent in 2000, 65 percent in 2010, and 67 percent in 2020.

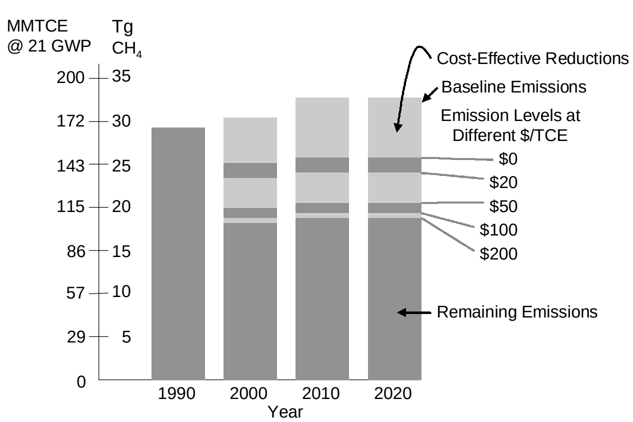
- **Enteric Fermentation**. Emissions from livestock enteric fermentation can be reduced through enhanced feeding and animal management techniques. The costs and cost-effectiveness of these reductions have not been quantified for this report.

The aggregate results of the analysis are presented in two ways. Exhibit ES-2 summarizes potential reductions across all sources at various carbon equivalent values. These reductions are the summation of source-specific results where different discount rates are applied to each source: 8 percent for landfills, 20 percent for natural gas systems, 15 percent for coal mining, and 10 percent for livestock manure management. For 2010, EPA estimates that up to 34.8 MMTCE (6.1 Tg) of reductions are possible at energy market prices or $0/TCE. Consequently, methane emissions could be reduced below 1990 emissions of 169.9 MMTCE (29.7 Tg) if many of the identified opportunities are thoroughly implemented. At higher emission reduction values, more methane reductions could be achieved. For example, EPA's analysis indicates that with a value of $20/TCE for abated methane added to the energy market price, U.S. reductions could reach 50.3 MMTCE (8.8 Tg) in 2010.

EPA also constructs marginal abatement curves (MACs) for each of the four sources along with an aggregate curve for 2010 which is shown in Exhibit ES-3. In order to properly construct the MAC for 2010, a discount rate of eight percent is equally applied to all sources.[1] MACs are derived by rank-ordering individual opportunities by cost per emission reduction amount. Methane values and marginal costs are denominated in both energy values (natural gas and electricity prices) and emission reduction values in terms of $/TCE. On the MACs, energy market prices are aligned to $0/TCE, where no additional price signals from emission reduction values exist to motivate reductions. At and below $0/TCE, all emission reductions are due to increased efficiencies, conservation of methane, or both. As a value is placed on methane emission reductions in terms of $/TCE, these values are added to the energy market prices and allow for additional reductions to clear the market. Any "below-the-line" reduction amounts, with respect to $0/TCE, illustrate this dual price-signal market, i.e., energy prices and emission reduction values.

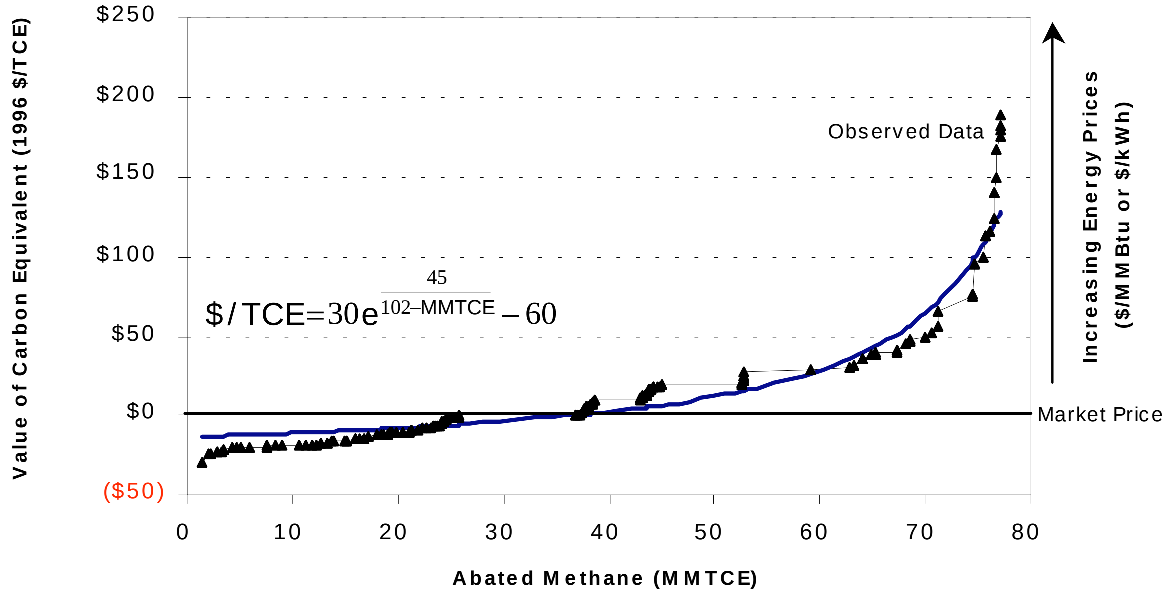
The aggregate U.S. MAC for 2010 in Exhibit ES-3 illustrates the following key findings. First, substantial emission reductions, 36.8 MMTCE (6.4 Tg), can be achieved at energy market prices with no additional emission reduction values ($0/TCE). Second, at

Exhibit ES-2: U.S. Baseline Emissions and Potential Reductions (source-specific discount rates) (MMTCE)



	2000	2010	2020
Baseline Emissions	173.9	186.0	183.7
Cumulative Reductions			
at $0/TCE	30.8	34.8	35.0
at $10/TCE	36.4	42.3	40.9
at $20/TCE	41.7	50.3	47.4
at $30/TCE	54.6	61.7	58.7
at $40/TCE	56.2	63.5	61.0
at $50/TCE	59.5	66.9	64.8
at $75/TCE	64.3	71.9	70.7
at $100/TCE	67.2	74.9	74.0
at $125/TCE	68.4	76.2	75.5
at $150/TCE	68.7	76.5	75.9
at $175/TCE	69.0	76.8	76.2
at $200/TCE	69.2	77.0	76.5
Remaining Emissions	104.7	108.9	107.2

Exhibit ES-3: Marginal Abatement Curve for U.S. Methane Emissions in 2010 (at an 8 percent discount rate)



$20/TCE and $50/TCE total estimated reductions are 52.6 MMTCE (9.2 Tg) and 70.0 MMTCE (12.2 Tg), respectively. Third, at $100/TCE, total achievable reductions are estimated at 75.5 MMTCE (13.2 Tg). Finally, above $100/TCE, the MAC becomes inelastic, that is, non-responsive to increasing methane values. This inelasticity indicates the limits of the options considered. The magnitude of the cost-effective and low-cost reductions reflects methane's value as an energy source and emphasizes that many proven technologies can be used to recover it. For several sources, the inelastic section of the curve at the higher end of the cost range indicates a limitation of the analysis, namely that only available technologies are assessed. Additional technologies may become available to reduce methane emissions at these prices; however, EPA has not yet assessed this possibility.

EPA has developed a number of voluntary programs as part of the Climate Change Action Plan (CCAP) to overcome market barriers and encourage cost-effective methane recovery projects. In this report, the emission reductions associated with these CCAP programs have not been subtracted from the baseline emission projections. However, EPA expects that approximately 50 percent of the reductions available in 2010 at $0/TCE will be captured by these programs. These programs have reduced emissions by 8 MMTCE in 1998 and are expected to reduce emissions by 12 MMTCE in 2000, and 20 MMTCE in 2010.

References

Dlugokencky, E.J., K.A. Masarie, P.M. Lang, and P.P. Tans. 1998. "Continuing Decline in the Growth Rate of the Atmospheric Methane Burden," *Nature*, v. 393, 4 June 1998.

EPA. 1999. *Inventory of Greenhouse Gas Emissions and Sinks 1990-1997*. Office of Policy, Planning, and Evaluation, U.S. Environmental Protection Agency, Washington, DC. (Available on the Internet at http://www.epa.gov/globalwarming/inventory/index.html.)

Endnotes

[1] In the construction of a national or aggregate marginal abatement curve, a single discount rate is applied to all sources in order to equally evaluate various options. Given a particular value for abated methane, all options up to and including that value can be cost-effectively implemented. An eight percent discount rate, the lowest in the range of the source-specific rates (8 to 20 percent), is used since it is closer to social discount rates employed in national level analyses. The results from the single, eight percent discount rate analysis are slightly higher than the results where source-specific discount rates are used because a lower discount rate reduces project costs enabling additional reductions.

1. Introduction and Aggregate Results

Introduction

This report has two objectives. First, it presents the U.S. Environmental Protection Agency's (EPA's) baseline forecast of methane emissions from the major anthropogenic sources in the U.S., and EPA's cost estimates of reducing these emissions. Emission estimates are given for 1990 through 1997 with projections for 2000 to 2020. The cost analysis is for 2000, 2010, and 2020. Second, this report provides a transparent methodology for the calculation of emission estimates and reduction costs, thereby enabling analysts to replicate these results or use the approaches described herein to conduct similar analyses for other countries.

The information presented in this report can be used in several ways. The emission estimates and forecasts represent the most up-to-date estimates of methane emissions in the U.S.; thus, this report replaces and expands upon EPA's *Anthropogenic Methane Emissions in the United States, Estimates for 1990, Report to Congress* (1993a). As such, this report can be used where estimates of future emissions are required. The report also summarizes the state of knowledge on methane emissions from the major anthropogenic sources.

While the emission estimations are refinements of earlier approaches, the cost analyses presented in this report represent a major contribution to the literature on mitigating emissions. To date, most economic analyses of greenhouse gas (GHG) emission reductions have focused on the energy-related carbon emissions since carbon dioxide (CO_2) currently accounts for about 82 percent of the total U.S. emissions (weighted by 100-year global warming potentials) (EPA, 1999). The cost-estimates for reducing methane emissions presented in this report can be integrated into economic analyses to produce more comprehensive assessments of total GHG reductions. By including methane emission reductions, the overall cost of reducing GHG emissions in the U.S. is reduced. At increasing values for emission reductions, more costly CO_2 reductions can be substituted by lower cost methane reductions, when available, thereby lowering the marginal cost and the total cost of a particular GHG emission reduction level.

The marginal abatement curves (MACs) developed in this report can be used to estimate possible emission reductions at various prices for carbon equivalent emissions or conversely, the costs of achieving certain amounts of reductions. EPA recognizes that the cost analyses will change with the introduction of new technologies and additional research into methane emission abatement technologies. Other countries, nevertheless, can use the cost analyses presented in this report as the basis for estimating emission reduction costs.

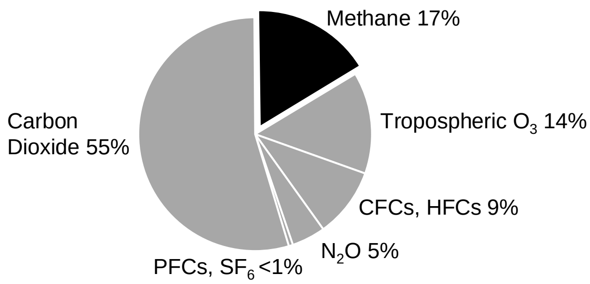
1.0 Overview of Methane Emissions

Next to carbon dioxide, methane is the second largest contributor to global warming among anthropogenic greenhouse gases. Methane's overall contribution to global warming is significant because, over a 100-year time frame, it is estimated to be 21 times more effective at trapping heat in the atmosphere than carbon dioxide. As illustrated in Exhibit 1-1, methane accounts for 17 percent of the enhanced greenhouse effect (IPCC, 1996a).[1]

Over the last two centuries, methane's concentration in the atmosphere has more than doubled from about 700 parts per billion by volume (ppbv) in pre-industrial times to 1,730 ppbv in 1997 (IPCC, 1996a). Exhibit 1-1 illustrates this trend. Scientists believe these atmospheric increases are largely due to increasing

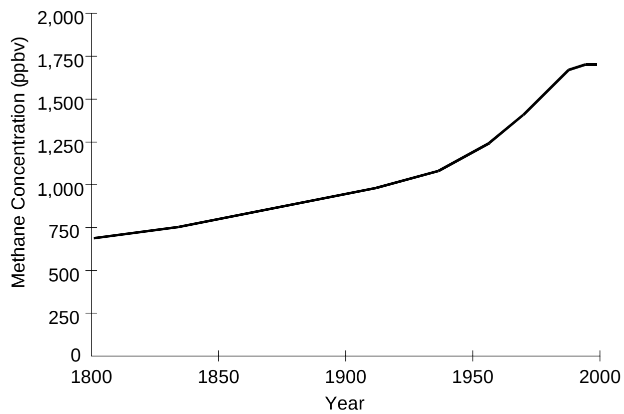
Exhibit 1-1: Global Enhanced Greenhouse Effect and Methane Concentrations

Contribution of Anthropogenic Gases to Enhanced Greenhouse Effect Since Pre-Industrial Times (measured in Watts/m^2)



Total = 2.85 Watts/m^2
Source: IPCC, 1996a.

Historical Global Atmospheric Methane Concentrations



Source: Boden, et al., 1994; Dlugokencky, et al., 1998.

emissions from anthropogenic sources. Although atmospheric methane concentrations continue to rise, the rate of increase appears to have slowed since the 1980s. If present trends continue, however, atmospheric methane concentrations will reach 1,800 ppbv by 2020 (Dlugokencky, et al., 1998).

Atmospheric methane is reduced naturally by sinks. Natural sinks are removal mechanisms and the greatest sink for atmospheric methane (CH_4) is through a reaction with naturally-occurring tropospheric hydroxyl (OH).[2] Methane combines with OH to form water vapor (H_2O) and carbon monoxide (CO), which in turn is converted into carbon dioxide (CO_2). Atmospheric methane, nevertheless, has a clearly defined chemical feedback that decreases the effectiveness of the hydroxyl sink. As methane concentrations rise, less hydroxyl is available to break down methane, producing longer atmospheric methane lifetimes and higher methane concentrations (IPCC, 1996a).

On average, the atmospheric lifetime for a methane molecule is 12.2 years (± 3 years) before a natural sink consumes it (IPCC, 1996a). This relatively short lifetime makes methane an excellent candidate for mitigating the impacts of global warming because emission reductions could lead to stabilization or reduction in methane concentrations within 10 to 20 years.

2.0 Sources of Methane Emissions

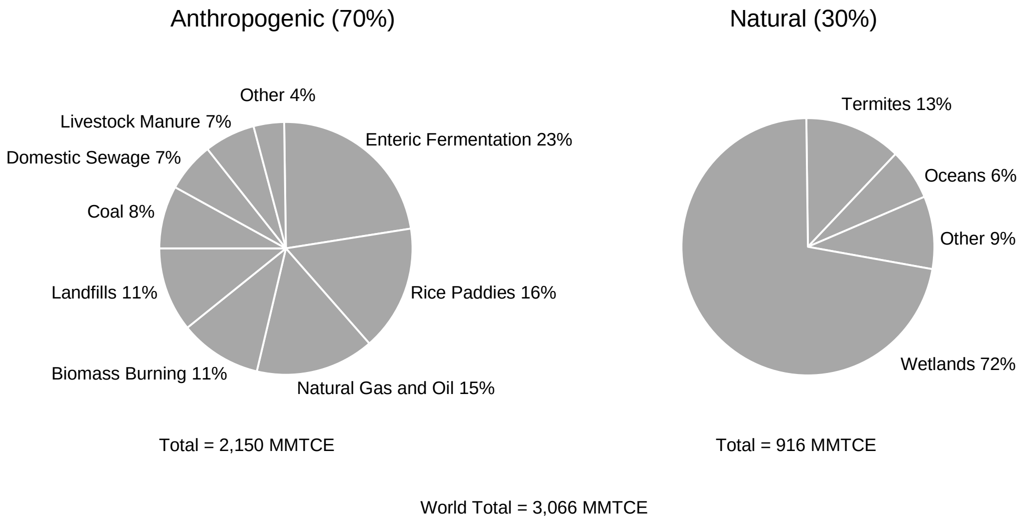
Methane is emitted into the atmosphere from both natural and anthropogenic sources. Natural sources include wetlands, tundra, bogs, swamps, termites, wildfires, methane hydrates, and oceans and freshwaters. Anthropogenic sources include landfills, natural gas and oil production and processing, coal mining, agriculture (livestock enteric fermentation and livestock manure management, and rice cultivation), and various other sources. By 1990, anthropogenic sources accounted for 70 percent of total global methane emissions (EPA, 1993a; IPCC, 1996a). This section summarizes the natural and anthropogenic sources of methane.

2.1 Natural Methane Emissions

In 1990, worldwide natural sources emitted 916 million metric tons of carbon equivalent (MMTCE) or 160 Teragrams (Tg) of methane into the atmosphere, or about 30 percent of the total methane emissions (IPCC, 1996a). The leading natural methane sources are described below in descending order of their contribution to emissions (see Exhibit 1-2).

Wetlands. Methane is generated by anaerobic (oxygen poor) bacterial decomposition of plant material in wetlands. Natural wetlands emit about 659 MMTCE

Exhibit 1-2: Worldwide Natural and Anthropogenic Methane Emissions in 1990



Source: IPCC, 1995 and 1996a.

(115 Tg) of methane per year, which is 72 percent of natural emissions and 20 percent of total global methane emissions (IPCC, 1995). Methane emissions from wetlands will probably increase with global warming as a result of accelerated anaerobic microbial activity. In addition, climate change models predict increased precipitation as global temperatures rise, which could create more wetlands (EPA, 1993b). Tropical wetlands (between 20° N and 30° S) represent 17 percent of total wetland area and 60 percent of emissions from wetlands. These relatively high emissions are due to higher temperatures, more precipitation and more intense solar radiation, which encourage higher plant growth and decomposition rates (EPA, 1993b).

Northern Wetlands (those above 45° N) are usually underlain with near-surface permafrost that prevents soil drainage and creates wetland conditions. Northern wetlands represent nearly 80 percent of the wetland area and 35 percent of methane emissions from wetlands (EPA, 1993b).

Termites. Microbes within the digestive systems of termites break down cellulose, and this process produces methane. Emissions from this source depend on termite population, amounts of organic material consumed, species, and the activity of methane-oxidizing bacteria. While more research is needed, some experts believe that future trends in termite emissions are more influenced by anthropogenic changes in land use, i.e., deforestation for agriculture, than by climate change. Termites emit an estimated 115 MMTCE (20 Tg) of methane each year (IPCC, 1995).

Oceans and Freshwaters. The surface waters of the world's oceans and freshwaters are slightly supersaturated with methane relative to the atmosphere and therefore emit an estimated 57 MMTCE (10 Tg) of methane each year (IPCC, 1995). The origin of the dissolved methane is not known. In coastal regions it may come from sediments and drainage. It also has been suggested that methane is generated in the anaerobic gastrointestinal tracts of marine zooplankton and fish (EPA, 1993b). Methane in freshwaters can result from the decomposition of wetland plants. (In this report, methane emissions from freshwaters are included in the estimates for wetlands.) As atmospheric methane concentrations increase, the proportion of methane supersaturated in oceans and freshwaters will decline relative to the atmospheric concentrations of methane, assuming that the methane concentration in oceans and freshwaters remains constant.

Gas Hydrates. Methane is trapped in gas hydrates, which are dense combinations of methane and ice located deep underground and beneath the ocean floor. Recent estimates of hydrates suggest that around 44 billion MMTCE (7.7 billion Tg) of methane is trapped in both oceanic and continental gas hydrates (DOE, 1998). Scientists agree that increasing temperatures will eventually destabilize many gas hydrates, but are unsure about the timing and the amount of methane emissions that would be released from the deeply buried hydrates (EPA, 1993b).

Permafrost. Small amounts of methane are trapped in permafrost, which consists of permanently frozen soil and ice. (To be classified as permafrost, the ice and soil mixture must remain at or below 0° Celsius year-round for at least two consecutive years.) Due to the large amount of existing permafrost, the total amount of methane stored in this form could be quite high, possibly several thousand Tg (EPA, 1993b). This methane is released when permafrost melts. However, no estimates have been made for current emissions from this source.

Wildfires. Wildfires are primarily caused by lightning and release a number of greenhouse gases, including methane which is a product of incomplete combustion. However, no estimates are available for methane emissions from this source.

2.2 Anthropogenic Methane Emissions

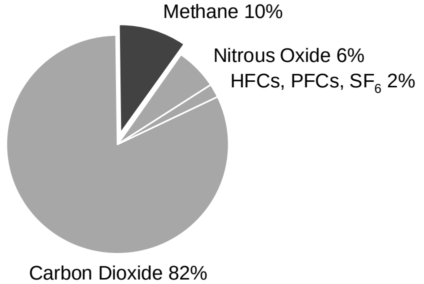
Methane emissions from anthropogenic sources account for 70 percent of all methane emissions and totaled 2,150 MMTCE (375 Tg) worldwide in 1990 (IPCC, 1996a). The leading global anthropogenic methane sources are described below in descending order of magnitude. The two leading sources of anthropogenic methane emissions worldwide are livestock enteric fermentation and rice production. By contrast, in the U.S., the two leading sources of methane emissions are landfills and natural gas and oil systems (see Exhibit 1-3). In 1997, the U.S. emitted 179.6 MMTCE (31.4 Tg) of methane, about 10 percent of global methane emissions for that year (EPA, 1999). The U.S. is the fourth-largest methane emitter after China, Russia, and India (EPA, 1994).

Enteric Fermentation. Ruminant livestock emit methane as part of their normal digestive process, during which microbes break down plant material consumed by the animal into material the animal can use. Methane is produced as a by-product of this digestive process, and is expelled by the animal. In the U.S., cattle emit about 96 percent of the methane from livestock enteric fermentation. In 1994, livestock enteric fermentation produced 490 MMTCE (85 Tg) of methane worldwide (IPCC, 1995), with the emissions coming from the former Soviet Union, Brazil, and India (EPA, 1994). EPA estimates that U.S. emissions from this source were 34.1 MMTCE (6.0 Tg) in 1997 (EPA, 1999). Under EPA's baseline forecast, livestock enteric fermentation emissions in the U.S. will increase to about 37.7 MMTCE (6.6 Tg) by 2020 (Exhibit 1-4). The projected increase is due to greater consumption of meat and dairy products.

Rice Paddies. Most of the world's rice, including rice in the United States, is grown on flooded fields where organic matter in the soil decomposes under anaerobic conditions and produces methane. The U.S. is not a

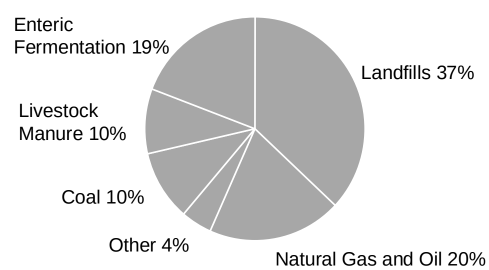
Exhibit 1-3: U.S. Methane Emissions

U.S. Greenhouse Gas Emissions in 1997
Weighted by Global Warming Potential



Total = 1,814 MMTCE
Source: EPA, 1999.

Source Breakdown of 1997 U.S. Methane Emissions



Total = 179.6 MMTCE
Source: EPA, 1999.

Exhibit 1-4: Baseline Methane Emissions in the United States (MMTCE)					
Source	**1990[a]**	**1997[a]**	**2000**	**2010**	**2020**
Landfills	56.2	66.7	51.4	52.0	41.1
Natural Gas Systems	32.9	33.5	35.6	37.9	38.8
Oil Systems	1.6	1.6	1.6	1.6	1.7
Coal Mining	24.0	18.8	23.9	28.0	30.4
Livestock Manure Management	14.9	17.0	18.4	22.3	26.4
Enteric Fermentation	32.7	34.1	35.2	36.6	37.7
Other[b]	7.3	7.4	7.8	7.6	7.6
Total	**169.9**	**179.6**	**173.9**	**186.0**	**183.7**

[a] Source: EPA, 1999.

[b] These estimates developed by EPA for the 1997 *Climate Action Report* (DOS, 1997).

Totals may not sum due to independent rounding.

major producer of rice and therefore emits little methane from this source. Worldwide emissions of methane from rice paddies were 345 MMTCE (60 Tg) in 1994 (IPCC, 1995), with the highest emissions coming from China, India, and Indonesia (EPA, 1994). EPA estimates U.S. emissions from this source at 2.7 MMTCE (0.5 Tg) in 1997 and expects emissions to remain stable in the future (EPA, 1999).

Natural Gas and Oil Systems. Methane is the major component (95 percent) of natural gas. During production, processing, transmission, and distribution of natural gas, methane is emitted from system leaks, deliberate venting, and system upsets (accidents). Since natural gas is often found in conjunction with petroleum, crude petroleum gathering and storage systems are also a source of methane emissions. In 1994, natural gas systems worldwide emitted 230 MMTCE (40 Tg) of methane and oil systems emitted 85 MMTCE (15 Tg) of methane (IPCC, 1995). EPA estimates that 1997 U.S. emissions were 33.5 MMTCE (5.8 Tg) from natural gas systems and 1.6 MMTCE (0.27 Tg) from oil systems (EPA, 1999). EPA expects emissions from oil systems to remain near 1997 levels through 2020. The baseline emission forecast is 38.8 MMTCE (6.8 Tg) from natural gas systems in 2020 (Exhibit 1-4). The increase results from higher consumption of natural gas and expansions of the natural gas system.

Biomass Burning. Biomass burning releases greenhouse gases, including methane, but is not a major source of U.S. methane emissions. In 1994, biomass burning produced 230 MMTCE (40 Tg) of methane worldwide (IPCC, 1995). EPA estimates that U.S. emissions from this source were 0.2 MMTCE (0.03 Tg) in 1997 and that emissions will remain stable through 2020 (EPA, 1999).

Landfills. Landfill methane is produced when organic materials are decomposed by bacteria under anaerobic conditions. In 1994, landfills produced 230 MMTCE (40 Tg) of methane worldwide (IPCC, 1995). EPA estimates that U.S. emissions from this source were 66.7 MMTCE (11.6 Tg) in 1997 (EPA, 1999). The baseline forecast is 41.1 MMTCE (7.2 Tg) from U.S. landfills in 2020 (Exhibit 1-4). Landfill methane is the only U.S. source that is expected to decline in the baseline over the forecast period. This decline is due to the implementation of the New Source Performance Standards and Emissions Guidelines (the Landfill Rule) under the Clean Air Act (March 1996). While the Landfill Rule controls greenhouse gas emissions that form tropospheric ozone (smog), it also will lead to lower methane emissions. The Landfill Rule requires large landfills to collect and combust or use landfill gas emissions.

Coal Mining. Methane is trapped within coal seams and the surrounding rock strata and is released during coal mining. Because methane is explosive in low concentrations, underground mines install ventilation systems to vent methane directly to the atmosphere. In 1994, coal mining produced 170 MMTCE (30 Tg) of methane worldwide (IPCC, 1995). EPA estimates that U.S. emissions from this source were 18.8 MMTCE

(3.3 Tg) in 1997 (EPA, 1999). EPA's baseline estimate indicates that emissions from coal mines could reach 30.4 MMTCE (5.3 Tg) by 2020 (Exhibit 1-4). The increase results from greater coal production from deep mines.

Domestic Sewage. The decomposition of domestic sewage in anaerobic conditions produces methane. Domestic sewage is not a major source of methane emissions in the U.S., where it is collected and processed mainly in aerobic (oxygen rich) treatment plants. In 1994, domestic sewage produced 145 MMTCE (25 Tg) of methane worldwide (IPCC, 1995). EPA estimates that emissions from sewage in the U.S. were 0.9 MMTCE (0.2 Tg) in 1997 and expects emissions to increase only slightly by 2020 (EPA, 1999). This increase will be due primarily to population increases.

Livestock Manure Management. The decomposition of animal waste in anaerobic conditions produces methane. Over the last eight years, methane emissions from manure have generally followed an upward trend. This trend is driven by: (1) increased swine and poultry production; and (2) increased use of liquid manure management systems, which create the anaerobic conditions conducive to methane production. In 1994, manure management produced 145 MMTCE (25 Tg) of methane worldwide (IPCC, 1995). EPA estimates that U.S. emissions from this source were 17.0 MMTCE (3.0 Tg) in 1997 (EPA, 1999). Emissions from livestock manure in the baseline are projected to increase to 26.4 MMTCE (4.6 Tg) by 2020 (Exhibit 1-4) mainly due to increases in livestock population and milk production.

3.0 Options for Reducing Methane Emissions

One of the key elements of the U.S. Climate Change Action Plan (CCAP) is the implementation of cost-effective reductions of methane emissions through voluntary industry actions.[3] Because methane is a valuable energy resource, recovering methane that normally would be emitted into the atmosphere and using it for fuel reduces greenhouse gas emissions. The methane saved from these voluntary actions often pays for the costs of recovery and also can be cost-effective even without accounting for the broader social benefits of reducing greenhouse gases (GHG).

Beginning in the early 1990s, EPA launched five voluntary programs to promote cost-effective methane emission reductions:

- AgSTAR Program – works with livestock producers to encourage methane recovery from animal waste;
- Coalbed Methane Outreach Program (CMOP) – works with the coal and natural gas industries to collect and use methane that is released during mining;
- Landfill Methane Outreach Program (LMOP) – works with states, municipalities, utilities, and the landfill gas-to-energy industry to collect and use methane from landfills;
- Natural Gas STAR Program – works with the companies that produce, transmit, and distribute natural gas to reduce leaks and losses of methane; and
- Ruminant Livestock Efficiency Program (RLEP) – works with livestock producers to improve animal nutrition and management, thereby boosting animal productivity and cutting methane emissions.

Under these voluntary programs, industry partners voluntarily undertake cost-effective efforts to reduce methane emissions. EPA works with partners to quantify the results of their actions and account for reductions in historical methane emission estimates. One of the principal benefits of these voluntary programs is the sharing of information between government and industry and within industry on emissions, and emission reduction opportunities and associated costs. These programs have contributed significantly to EPA's understanding of the opportunities for emission reductions.

Many of these opportunities involve the recovery of methane emissions and use of the methane as fuel for electricity generation, on-site heat uses, or off-site sales of methane. These actions represent key opportunities for reducing methane emissions from landfills, coal mines, and livestock manure management. Other options may include oxidizing or burning the methane emissions. Catalytic oxidation is a new technology potentially applicable at coal mines; flaring is an option available at landfills and other sites.

The natural gas industry offers the most robust array of emission reduction options. The Natural Gas STAR Program has identified a number of best management practices for reducing leaks and avoiding venting of methane. In addition, partners in the program have employed a number of other strategies for reducing emissions. These strategies are described in the chapter on natural gas systems.

Conversely, few technology-specific reduction options have yet been identified for the ruminant livestock industry, where methane production is a natural byproduct of enteric fermentation. The principal options are improving the efficiency of feedlot operations and animal feeds for ruminant livestock. Better feeds and animal management can increase yields of meat and dairy products relative to methane production.

A principal benefit of the various voluntary programs is abundant information developed on the efficacy of the emission reduction options and the costs of implementing these options. EPA uses this information to estimate the costs of reducing emissions. Partners in the various voluntary programs are already undertaking emission reduction efforts because they have been found to be cost-effective. While some of the emission reduction options are cost-effective in some settings, they are not in others, e.g., methane recovery and use may be more cost-effective at large coal mines and landfills than at small ones. In the next section the economics of decision making in the implementation of reduction options is discussed.

4.0 Economic Analysis of Reducing U.S. Methane Emissions

This report presents the results of extensive benefit-cost analyses conducted on the opportunities (technologies and management practices) to reduce methane emissions from four of the five major U.S. sources: landfills, natural gas systems, coal mining, and livestock manure. The analyses are conducted for the years 2000, 2010, and 2020. EPA selected these sources because well-characterized opportunities exist for cost-effective emission reductions. The results are in terms of abated methane (emission reductions) that can be achieved at various values of methane. The total value of methane is the sum of its value as a source of energy and as an emission reduction of a GHG.

Methane has a value as a source of energy since it is the principal component of natural gas. Therefore, avoided methane emissions in natural gas systems are valued in terms of dollars per million British thermal units ($/MMBtu). Similarly, methane also can be combusted to generate electricity and is valued in dollars per kilowatt-hour ($/kWh). The value of potential methane emission reductions is calculated relative to carbon equivalent units using methane's 100-year global warming potential (GWP) of 21 (IPCC, 1996a). The value of abated methane, as well as other GHGs, can thus be stated in terms of dollars per metric ton of carbon equivalent ($/TCE). Throughout the analysis, energy market prices are aligned to $0/TCE. This value represents a scenario where no additional price signals from GHG abatement values exist to motivate emission reductions; all reductions are due to responses to market prices for natural gas. As a value is placed on GHG reductions in terms of $/TCE, these values are added to energy market prices and allow for additional emission reductions to clear the market.

A benefit-cost analysis is applied to the opportunities for emission reductions and is defined as:

- **Benefits.** Benefits are calculated from the amount of methane saved by implementing the options multiplied by the value of the methane saved as its use as an energy resource; plus the value of methane as an emission reduction of a GHG, if available;
- **Costs (including capital expenditures and operation and maintenance expenses).** The costs of implementing specific reduction options are estimated for four of the five major anthropogenic sources. The applied discount rates are particular to each source-specific

analysis and set at eight percent for the aggregate analysis.[4] In the source-specific analyses, different discount rates are used to determine cost-effective reductions.

Because nearly all of the technologies and practices for reducing methane emissions produce or save energy, energy prices are a key driver of the cost analyses. The value of the energy produced or saved offsets to various degrees the capital and operating costs of reducing the emissions. Higher energy prices offset a larger portion of these costs, and in some cases make the technologies and practices profitable.[5]

In the source-specific analyses, energy market prices, in 1996 U.S. dollars, are used to establish whether an option is cost-effective. These prices are established based on the following approaches:

- For landfills, both electricity and natural gas prices are used in the analysis since landfills sell gas directly to consumers or use the recovered gas to generate electricity. For electricity prices, the analysis uses an estimated price of $0.04/kWh to represent the value of electricity close to distribution systems and receiving a renewable energy premium. For natural gas, the price used is $2.74/MMBtu. In this case, the analysis uses the average industrial gas price discounted by 20 percent to adjust for the lower Btu content of landfill gas (EIA, 1997).

- Coal mine methane is sold as natural gas to interstate pipelines, used to generate electricity, or used on-site. For natural gas, coal mine methane is valued at $2.53/MMBtu, which is the average delivered price for natural gas in Alabama, Indiana, Kentucky, and Ohio. The electricity generated from coal mines is valued at $0.03/kWh to reflect the greater distance from distribution systems.

- The set of energy prices for natural gas systems depends on where the emissions are reduced. Production emission reductions are valued at the average wellhead price of $2.17/MMBtu; transmission savings are valued at $2.27/MMBtu; and distribution system savings are valued at $3.27/MMBtu (EIA, 1997).

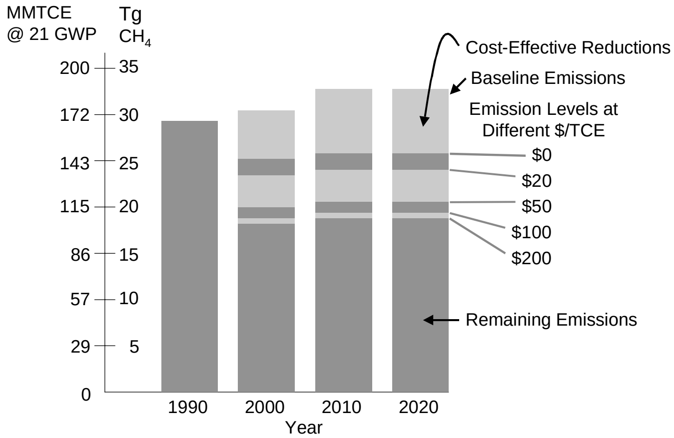
- Livestock manure methane is used to generate electricity for farm use and offset electricity consumption from a utility grid. The analysis uses $0.09/kWh for dairy farms and $0.07/kWh for swine farms. These prices are weighted averages of retail commercial electricity rates based on dairy and swine populations, respectively. The national average price was discounted by $0.02/kWh to reflect the effects of interconnect and demand charges and other associated costs.

In order to incorporate methane emission reduction values into the analysis, various $/TCE values are translated into equivalent electricity and gas prices using the heat rate of the engine-generator (for electricity), the energy value of methane (1,000 Btu/cubic foot), and a GWP of 21. See individual chapters for greater detail.

5.0 Achievable Emission Reductions and Composite Marginal Abatement Curve

The aggregate results of the analyses are presented in this section. Exhibit 1-5 shows estimated total U.S. reductions at various values for abated methane in $/TCE. These reductions are the summation of source-specific results where different discount rates are applied to each source: 8 percent for landfills, 10 percent for livestock manure management, 15 percent for coal mining, and 20 percent for natural gas systems. For 2010, EPA estimates that up to 34.8 MMTCE (6.1 Tg) of reductions are possible at energy market prices or $0/TCE. Consequently, methane emissions could be reduced below 1990 emissions of 169.9 MMTCE (29.7 Tg) if many of the identified opportunities are thoroughly implemented. At higher emission reduction values, more methane reductions could be achieved. For example, EPA's analysis indicates that with a value of $20/TCE for abated methane

Exhibit 1-5: U.S. Baseline Emissions and Potential Reductions (source-specific discount rates) (MMTCE)



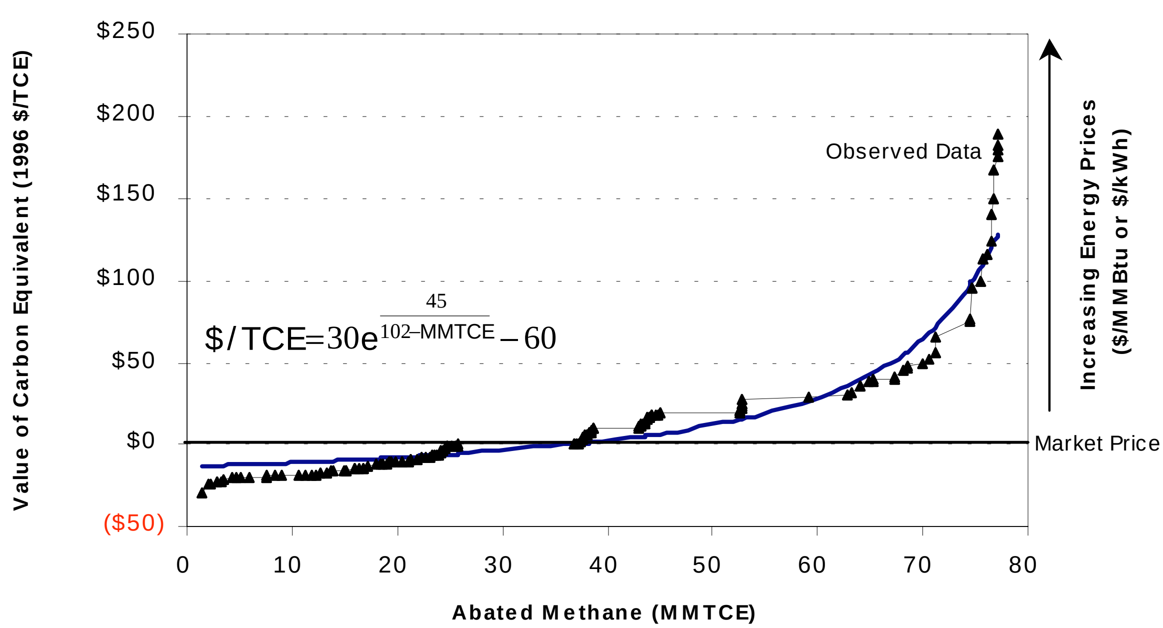
	2000	2010	2020
Baseline Emissions	173.9	186.0	183.7
Cumulative Reductions			
at $0/TCE	30.8	34.8	35.0
at $10/TCE	36.4	42.3	40.9
at $20/TCE	41.7	50.3	47.4
at $30/TCE	54.6	61.7	58.7
at $40/TCE	56.2	63.5	61.0
at $50/TCE	59.5	66.9	64.8
at $75/TCE	64.3	71.9	70.7
at $100/TCE	67.2	74.9	74.0
at $125/TCE	68.4	76.2	75.5
at $150/TCE	68.7	76.5	75.9
at $175/TCE	69.0	76.8	76.2
at $200/TCE	69.2	77.0	76.5
Remaining Emissions	104.7	108.9	107.2

added to the energy market price, U.S. reductions could reach 50.3 MMTCE (8.8 Tg) in 2010.

Exhibit 1-6 presents EPA's aggregate U.S. methane marginal abatement curve (MAC) for 2010 which is calculated using a discount rate of eight percent equally applied to all sources in order to properly construct the curve.[4] The MAC illustrates the amount of reductions possible at various values for methane and is derived by rank ordering individual opportunities by cost per emission reduction amount (IPCC, 1996b). Any point along a MAC represents the marginal cost of abating an additional amount of methane. A complete picture is revealed when the prevailing market prices for energy and GHG reductions are applied to the MAC to show the amount of available emissions that clear the market. Any "below-the-line" reduction amounts, with respect to $0/TCE, illustrate this dual price-signal market, i.e., energy market prices and emission reduction values.

The MAC illustrates the following key findings. First, substantial emission reductions, 36.8 MMTCE (6.4 Tg), can be cost-effectively achieved, that is, at energy market prices with no additional emissions reduction values or $0/TCE. Second, at $20/TCE and $50/TCE

Exhibit 1-6: Marginal Abatement Curve for U.S. Methane Emissions in 2010 (at an 8 percent discount rate)



estimated reductions are 52.6 MMTCE (9.2 Tg) and 70.0 MMTCE (12.2 Tg), respectively. Third, at $100/TCE, achievable reductions are estimated at 75.5 MMTCE (13.2 Tg). Finally, above $100/TCE, the MAC becomes inelastic, that is, non-responsive to increasing methane values which indicates the limits of the options considered. At higher energy and emission reduction values, additional options, which have yet to be developed, will likely become available. By not estimating potential, future higher-cost options, this analysis under-estimates the ability to reduce emissions at higher values for abated methane.

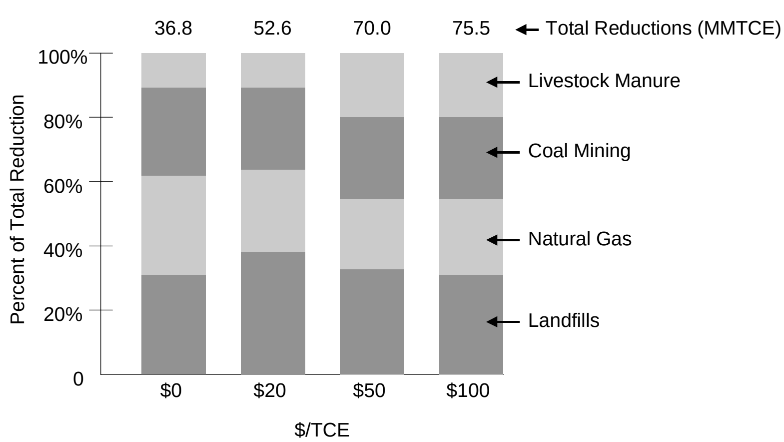
The MAC is based on approximately 160 observations. These results are from the benefit-cost analyses conducted on the identified opportunities to abate methane emissions.

An analytic approximation of the MAC is calculated in order to make these results useful to larger economic models concerned with GHG reduction costs. The estimated relationship is obtained by using an exponential trendline, expressing the relationship between methane values/abatement costs and the quantity of abated methane.[6] This function is described as: $/TCE = 30 exp [45/(102 – MMTCE)]-60.

Exhibit 1-7 illustrates the relative contribution of each of the sources to reducing methane emissions. Of the four sources, landfills contribute the most to the emission reductions, i.e., over one-quarter of the reductions. Coal mining and natural gas systems each account for about one-quarter of total emission reductions. Livestock manure contributes up to about one-fifth of the reductions, primarily at higher energy prices and emission reduction values. Several key aspects of the analysis are highlighted below:

- The methane recovery efficiency at landfills is estimated at 75 percent for all landfills and is assumed to remain constant. Below $0/TCE, using the recovered methane directly in boilers or similar equipment is more cost-effective than producing electricity in most cases.
- Because of the diverse sources of methane emissions from natural gas systems, a large number of technologies and practices are evaluated. Among the options evaluated, replacing high-bleed pneumatic devices and techniques for reducing emissions from compressor stations are the most significant in terms of cost-effective emission reductions.
- The coal mine methane analysis includes a catalytic oxidation technology for recovering heat energy from the low concentration of methane in coal mine ventilation air. This technology becomes profitable at approximately $30/TCE, leading to substantial emission reductions from underground mining. Below this value, methane recovery is the primary method of reducing emissions.
- The principal methods for reducing methane emissions from livestock manure are to collect and combust the methane that would other-

Exhibit 1-7: Portion of Emission Reductions from Each Source in 2010 (at an 8 percent discount rate) (MMTCE)



wise be emitted from liquid manure management systems. Anaerobic digester technologies, the principal technology evaluated, produce multiple benefits, including odor reduction at swine farms as well as producing energy for on-farm use.

6.0 Significance of This Analysis

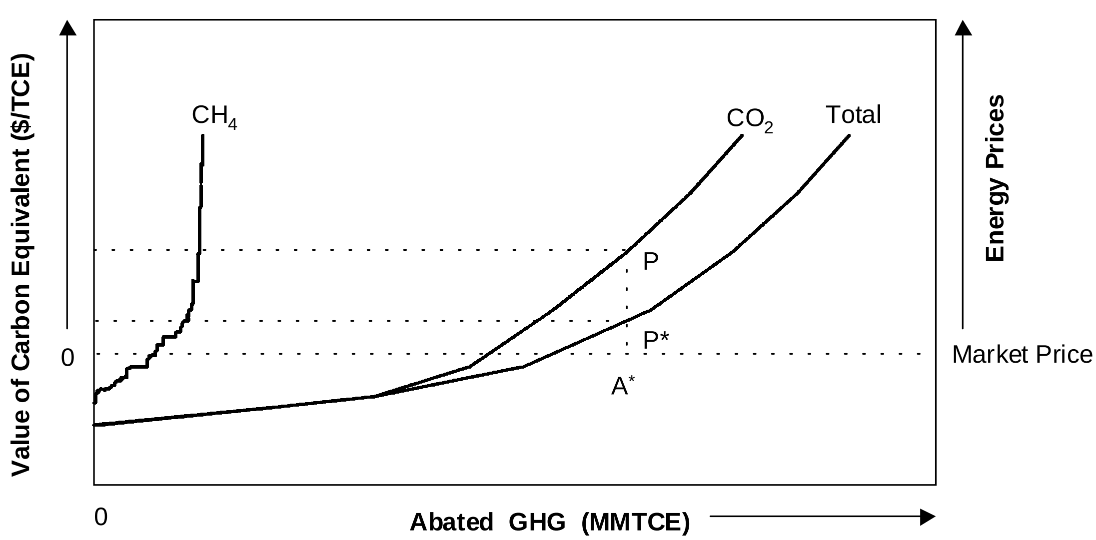
To date, most economic analyses of GHG reduction opportunities have focused on energy-related carbon emissions since CO_2 currently accounts for about 82 percent of the total U.S. emissions (weighted by 100-year global warming potentials) (EPA, 1999). The analyses provided in this report can be integrated with CO_2 economic analyses to provide a broader understanding of reducing the total cost of achieving GHG emission reductions. Recent comprehensive studies by the Joint Program on the Science and Policy of Global Change, Massachusetts Institute of Technology (Reilly, 1999) and the Australian Bureau for Agricultural and Resource Economics (Brown, 1999) show that a multi-gas mitigation strategy can reduce the costs of achieving GHG emission reductions. Both of these studies utilized EPA's preliminary cost analysis on methane reductions (EPA, 1998).

The economic benefits of pursuing a mitigation strategy that includes methane is shown in Exhibit 1-8. Illustrative MACs are presented for methane (CH_4), CO_2, and for the summation of the two showing additional emission reductions with increases in $/TCE. Given a reduction target, A*, for both gases, the total cost of achieving that target is lower if available methane reductions are included than if only CO_2 reductions are made. At increasing values for emission reductions, more costly CO_2 reductions can be substituted by lower cost methane reductions, when available, thereby lowering the marginal cost, shown as the movement from P to P*, and decreasing the total cost (the integral or area under the curve).

7.0 Background to This Report

EPA's first major report on methane appeared in 1993 as *Anthropogenic Methane Emissions in the United States, Estimates for 1990, Report to Congress* (1993a). This report was the first effort to increase general knowledge about methane emissions by presenting a detailed and comprehensive treatment of the sources of methane emissions as part of the effort to quantify these emissions. Following this report, EPA published Opportunities to Reduce Anthropogenic

Exhibit 1-8: Illustrative MACs for Methane and Carbon Dioxide



Methane Emissions in the United States (EPA, 1993b). For all major sources of methane emissions – landfills, natural gas systems, coal mines, livestock manure, and livestock enteric fermentation – this report described the technologies available that could reduce emissions. Using these technologies, the report estimated the amount of emission reductions that would be technically feasible and the amount of emission reductions that would be economically justified. The latter included taking into account the value of methane (as a fuel) as well as a value for emission reductions.

Since the publication of these reports, EPA has sponsored additional work in the estimation of baseline emissions and the costs of emission reductions. These efforts include, for example, a 15-volume report on Methane Emissions from Natural Gas Systems co-sponsored with the Gas Research Institute (EPA/GRI, 1996).

The information from the various voluntary programs in addition to other research was used extensively in the EPA's Costs of Reducing Methane Emissions in the United States, Preliminary Report (EPA, 1998). This report first developed the overall approach for estimating the cost of emission reductions and was reviewed by a number of industry and source experts. Their subsequent recommendations as well as other improvements have been incorporated into the current document.

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9.0 Explanatory Notes

[1] The enhanced greenhouse effect is the concept that the natural greenhouse effect has been enhanced by anthropogenic emissions of greenhouse gases. Increased concentrations of carbon dioxide, methane, and nitrous oxide, CFCs, HFCs, PFCs, SF_6, and other photochemically important gases caused by human activities such as fossil fuel consumption, trap more infra-red radiation, thereby exerting a warming influence on climate. Exhibit 1-1, which illustrates relative contributions to the enhanced greenhouse effect by gas, is based on the increase in atmospheric concentrations at each gas between pre-industrial times and 1992. This exhibit does not include methane's indirect effect of tropospheric ozone and stratospheric water vapor production, which are estimated to be equivalent to about 25 percent of the direct effects.

[2] Microbial communities in upper soils constitute a much smaller methane sink.

[3] The U.S. CCAP was initiated in 1993 and designed to reduce U.S. emissions of greenhouse gases. CCAP Programs promote actions that are both cost-effective for individual private sector participants as well as beneficial to the environment.

[4] In the construction of a national or aggregate marginal abatement curve, a single discount rate is applied to all sources in order to equally evaluate various options. Given a particular value for abated methane, all options up to and including that value can be cost-effectively implemented. An eight percent discount rate, the lowest in the range of the source-specific rates (8 to 20 percent), is used since it is closer to social discount rates employed in national level analyses. The results from the single, eight percent discount rate analysis are slightly higher than the results where source-specific discount rates are used because a lower discount rate reduces project costs enabling additional reductions.

[5] The effects of energy price changes are analyzed only from the revenue side and do not consider effects to capital and O&M expenses. Therefore, the projected methane reductions may be overestimated for increases and underestimated for decreases to energy prices.

[6] For the estimated relationship, $/TCE = 30 exp [45/(102 – MMTCE)] - 60, the regression analysis yielded an R^2 of 0.95. Conversely, the relationship also can be expressed in standard economic terms as the quantity of abated methane as a function of price ($/TCE): MMTCE = 102 – 45/ln [($/TCE+60)/30].

2. Landfills

Summary

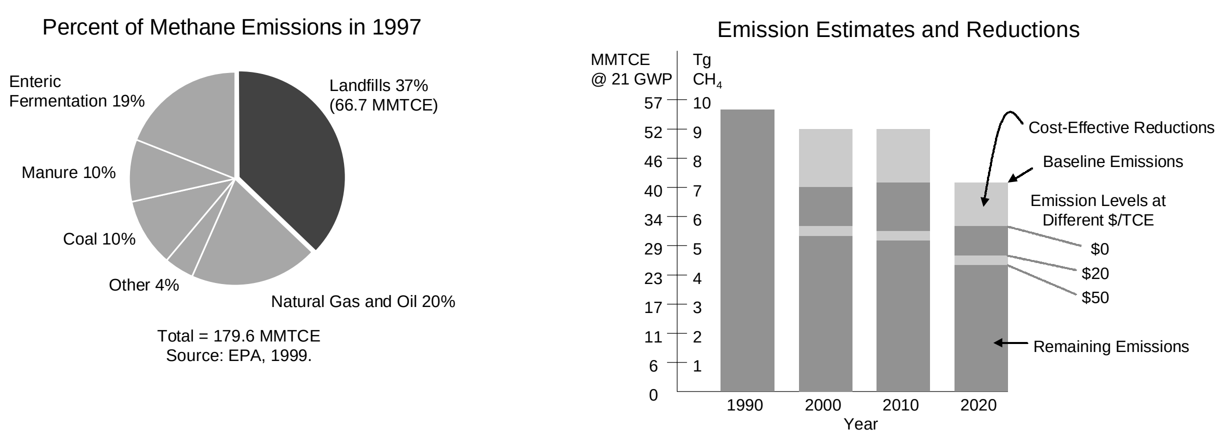
Landfills are the largest source of U.S. methane emissions and emitted approximately 66.7 MMTCE (11.6 Tg) of methane or 37 percent of total U.S. emissions in 1997 (EPA, 1999). Municipal solid waste landfills, which receive about 61 percent of U.S. solid waste, generate 93 percent of U.S. landfill emissions, while industrial landfills account for the remaining emissions. Over 2,500 landfills currently operate in the U.S. with a small number of the largest landfills receiving most of the waste and generating the majority of methane emissions (BioCycle, 1998).

EPA expects future landfill methane emissions to decline due to the Landfill Rule (New Source Performance Standards and Emissions Guidelines), which was promulgated under the Clean Air Act in March 1996 and amended in June 1998 (EPA, 1996, 1998). The Landfill Rule requires landfill gas to be collected and either flared or used at landfills that: (1) have a design capacity greater than 2.5 million metric tons (MMT) and 2.5 million cubic meters; and (2) emit at least 50 metric tons (MT) per year of non-methane organic compounds (NMOCs). Although the Landfill Rule controls NMOC emissions because they contribute to tropospheric ozone (smog) formation, the process of reducing them also reduces methane emissions. Under the Landfill Rule, EPA expects landfill methane emissions to decline to 52.0 MMTCE (9.1 Tg) in 2010, excluding possible additional Climate Change Action Plan and other reductions.[1]

Landfill methane emissions can be reduced through methane recovery and use projects, as well as flaring. Currently, over 250 U.S. landfills have methane utilization projects. The recovered methane is used as on-site fuel, used to generate electricity, or sold to energy end-users, such as factories. Recovering landfill methane also reduces odors and the risk of methane migration through soil.

Exhibit 2-1 shows baseline emissions decreasing between 1990-2020. Although not shown, baseline emissions increase between 1990-1997. After 1997, emissions decrease due to the Landfill Rule. In addition, Exhibit 2-1 shows that by implementing cost-effective technologies and practices, the U.S. could reduce methane emissions from landfills by up to 10.5 MMTCE (1.8 Tg) in 2010 at energy market prices (in 1996 US$) or $0/TCE. At higher emission reduction values, more methane reductions could be achieved. For example, EPA's analysis indicates that with a value of $20/TCE for abated methane added to the energy market price, baseline emissions could decrease to 31.8 MMTCE and U.S. reductions could reach 20.2 MMTCE (3.5 Tg) in 2010.

Exhibit 2-1: U.S. Methane Emissions from Landfills (MMTCE)



1.0 Methane Emissions from Landfills

Solid waste landfills produce methane as bacteria decompose organic wastes under anaerobic conditions. Methane accounts for approximately 45 to 50 percent of landfill gas, while carbon dioxide and small quantities of other gases comprise the remaining 50 to 55 percent. Methane production begins six months to two years after waste disposal and may last for decades, depending on disposal site conditions, waste characteristics, and the amount of waste in the landfill. Methane migrates out of landfills and through zones of low pressure in soil, eventually reaching the atmosphere. During this process, the soil oxidizes approximately ten percent of the methane generated by a landfill, and the remaining 90 percent is emitted as methane unless captured by a gas recovery system and then used or flared (Liptay, et al., 1998).

This section presents background information on the factors influencing methane generation and the methods EPA uses to estimate both current and future emissions. A description of the five primary factors that influence landfill methane production are discussed first, followed by a discussion of the emission estimation method used for this analysis. Next, the current and projected emission estimates for U.S. landfills are presented. Lastly, the uncertainties associated with the emission estimates are discussed.

1.1 Emission Characteristics

The amount and rate of methane production over time at a landfill depends on five key characteristics of the landfilled material and surrounding environment. These characteristics are briefly summarized below.

Quantity of Organic Material. The most significant factor driving landfill methane generation is the quantity of organic material, such as paper and food and yard wastes, available to sustain methane-producing microorganisms. The methane production capacity of a landfill is directly proportional to its quantity of organic waste. Methane generation increases as the waste disposal site continues to receive waste and gradually declines after the site stops receiving waste. However, landfills may continue to generate methane for decades after closing.

Nutrients. Methane generating bacteria need nitrogen, phosphorus, sulfur, potassium, sodium, and calcium for cell growth. These nutrients are derived primarily from the waste placed in the landfill.

Moisture Content. The bacteria also need water for cell growth and metabolic reactions. Landfills receive water from incoming waste, surface water infiltration, groundwater infiltration, water produced by decomposition, and materials such as sludge. Another source of water is precipitation. In general, methane generation occurs at slower rates in arid climates than in non-arid climates.

Temperature. Warm temperatures in a landfill speed the growth of methane producing bacteria. The temperature of waste in the landfill depends on landfill depth, the number of layers covering the landfill, and climate.

pH. Methane is produced in a neutral environment (close to pH 7). The pH of most landfills is between 6.8 and 7.2. Above pH 8.0, methane production is negligible.

1.2 Emission Estimation Method

Estimating the quantity of municipal solid waste-in-place (WIP) that contributes to methane emissions requires a characterization of the current and expected future population of landfills. EPA characterizes each landfill in terms of its year of opening, waste acceptance during operation, year of closure, and design capacity. The landfill population as of 1990 is based on EPA's landfill survey (EPA, 1988). The future population of landfills is modeled by simulating the closure of existing landfills as they reach their design capacity and the opening of new landfills when a significant shortfall in disposal capacity is predicted. Simulated new landfills are assumed to be larger, on average, than the landfills they are replacing, reflecting the trend toward fewer and larger regional waste disposal facilities.

EPA simulates the opening and closing of landfills based on waste disposal estimates. For 1990 through 1997, waste disposal estimates are based on annual BioCycle data (BioCycle, 1998).[2] The uncertainty in predicting future waste disposal levels is due to significant shifts in waste disposal practices. Therefore, for the years after 1997, this analysis uses a constant overall disposal rate based on the average rate from 1990 to 1995. This simplification is based on the assumption that the total amount of municipal solid waste (MSW) generated will increase while the percentage of waste landfilled will decline due to rising recycling and composting rates (EPA, 1997a).

The current and future national quantity of waste disposed is apportioned across an assumed population of landfills. Exhibit 2-2 shows the landfill sizing assumptions for each category used in the population analysis. (See Appendix II, Exhibit II-3 for the distribution of waste disposal across the landfill categories). The analysis annually updates the landfill characteristics, i.e., the total WIP and years of operation. The result is a simulated population of landfills reflecting the national MSW disposal rates over time.

Exhibit 2-2: Landfill Capacity Assumptions

Landfill Category	Capacity (MT)
Small	500,000
Small-Medium	1,000,000
Medium	5,000,000
Large	15,000,000
Very Large	> 15,000,000

MT = metric tons

1.3 Emission Estimates

EPA uses the results of the landfill population analysis to calculate the methane emissions from MSW landfills. The quantity of waste in landfills over time drives methane generation. An emissions model uses this landfill-specific data to estimate the amount of methane produced by MSW landfills in a given year (EPA, 1993). The model is based on information from 85 landfills that represent the population of U.S. landfills and vary in terms of depth, age, regional distribution, and other factors.

As indicated in Exhibit 2-3, annual landfill methane emissions are calculated by summing annual methane generated from MSW landfills, subtracting methane recovered and oxidized, and adding methane emissions from industrial solid waste.

Exhibit 2-3: Components of Methane Emissions from Landfills

Total Landfill Methane Emissions

Equals

Methane Generated from Municipal Solid Waste (MSW Landfills)

Less

Methane Recovered and Flared or Used for Energy

Less

Methane Oxidized from MSW Landfills

Plus

Methane Emissions from Industrial Waste Sites

Exhibit 2-4 presents estimates of the amount of municipal solid waste contributing to methane emissions for the years 1990 to 1997. Methane generation coefficients are applied to the WIP to determine total methane generated for individual landfills for the same period.[3]

The analysis also assesses the applicability of the Landfill Rule based on methane generated for each landfill. The Landfill Rule (New Source Performance Standards and Emissions Guidelines) was promulgated in March 1996 under the Clean Air Act and amended in June 1998. The Landfill Rule requires gas collection and flaring or other combustion at landfills whose design capacity exceeds 2.5 million metric tons (MMT) and 2.5 million cubic meters (million m^3), and that emit 50 metric tons per year (MT/yr) of non-methane organic compounds (NMOCs). EPA estimates that up to 350 existing and 50 new landfills will install gas control systems by 2000 under the Landfill Rule.[4] The emission model identifies which landfills are subject to the Landfill Rule and projects baseline emissions accordingly. Thus, for the purposes of the cost analysis presented in this chapter, EPA analyzes only landfills with emissions below the Landfill Rule threshold.

Although not explicitly modeled in this analysis, EPA has estimated methane reductions under the Climate Change Action Plan (CCAP). Under CCAP, the Landfill Methane Outreach Program (LMOP) has promoted methane recovery and utilization. LMOP/CCAP reductions reflect those landfills at which LMOP has provided assistance.

1.3.1 Current Emissions and Trends

The amount of MSW in landfills contributing to methane emissions increased from approximately 4,900 MMT in 1990 to approximately 5,800 MMT in 1997. Methane emissions also increased between 1990 and 1997, from 56.2 million metric tons of carbon equivalent (MMTCE) or 9.8 Teragrams (Tg) to 66.7 MMTCE or 11.6 Tg, respectively (EPA, 1999). Exhibit 2-5 shows this gradual increase of 1.5 MMTCE/yr (0.26 Tg/yr). Although emissions increased, methane collection and combustion by landfill operators also increased from an estimate of 8.6 MMTCE (1.5 Tg) in 1990 to 10.3 MMTCE (1.8 Tg) in 1992. Since 1992, the number of landfill gas recovery projects has increased substantially. EPA is developing annual recovery estimates for gas utilization projects for the period 1990-1998. These estimates will be published in 2000, and may result in a stable emissions trend over the period 1990-1998.

For purposes of electricity generation, the U.S. recovered 6.9 MMTCE (1.2 Tg) of landfill methane in 1990 and 8.1 MMTCE (1.4 Tg) in 1992 (GAA, 1994). To account for methane flared without energy recovery, the recovery estimate is increased by 25 percent to arrive at the total methane recovered (EPA, 1993). Due to a current lack of information on annual recovery rates, the 1990 estimate is used for 1991, and the 1992 estimate is used for 1993 through 1997.

1.3.2 Future Emissions and Trends

As previously stated, total emissions are based on a characterization of the surveyed U.S. landfill population. The surveyed population, however, excludes industrial landfills and landfills with a WIP less than 500,000 MT; therefore, the emissions from these landfills are estimated as a percentage of MSW emissions from the surveyed population. Emissions for the small landfills (containing less than 500,000 MT) are based on an estimate of the portion of total waste disposed in small landfills. This portion is estimated to decline from 12 percent of current MSW emissions to six percent of the MSW emissions by 2020. Industrial landfill emissions are as-

Exhibit 2-4: Municipal Solid Waste Contributing to Methane Emissions (MMT)

Description	1990	1991	1992	1993	1994	1995	1996	1997
Total MSW Generated[a]	267	255	265	279	293	297	297	309
Percent of MSW Landfilled[b]	77%	76%	72%	71%	67%	63%	62%	61%
Total MSW Landfilled	206	194	191	198	196	187	184	189
Cumulative MSW Contributing to Emissions[c]	4,926	5,027	5,162	5,292	5,428	5,560	5,677	5,791

MMT = million metric tons

[a,b] Source: BioCycle, 1998.

[c] The EPA emission model (EPA, 1993) assumes all waste that has been in place for less than 30 years emits methane.

Exhibit 2-5: Methane Emissions from Landfills (MMTCE)

Activity	1990	1991	1992	1993	1994	1995	1996	1997
MSW Landfilling	66.4	67.8	69.7	71.6	73.6	75.7	77.3	78.9
Recovery	(8.6)	(8.6)	(10.3)	(10.3)	(10.3)	(10.3)	(10.3)	(10.3)
Oxidation from MSW	(5.8)	(5.9)	(5.9)	(6.1)	(6.3)	(6.5)	(6.7)	(6.9)
Industrial Waste Landfilling	4.2	4.3	4.4	4.5	4.6	4.8	4.9	5.0
Total	**56.2**	**57.6**	**57.8**	**59.7**	**61.6**	**63.6**	**65.1**	**66.7**

MMTCE = million metric tons of carbon equivalent

Totals may not sum due to independent rounding.

sumed to equal seven percent of the total methane generated from MSW at all landfills, including those with less than 500,000 MT. The emissions from industrial and small landfills are added to the total MSW methane emissions and are included in baseline emissions. Excluding the small and industrial landfills, approximately 3,900 existing and future landfills are simulated in the U.S. landfill population. Of these, approximately 2,030 existed in 1990.

Future landfill methane emissions will decline due to the Landfill Rule and increased recycling and alternative waste disposal methods. Based on the annual quantity of waste disposed and the criteria for the Landfill Rule, EPA simulates candidate landfills for methane recovery. Since the analysis incorporates projected waste quantities, it reflects the fact that certain landfills will not be subject to the Landfill Rule, and others will not have enough waste to cost-effectively recover and use methane until some time in the future. Exhibit 2-6 shows estimated landfill methane emissions with and without the Landfill Rule for 2000 through 2020. Baseline emission projections include emission reductions achieved as a result of the Landfill Rule.

1.4 Emission Estimate Uncertainties

The primary source of uncertainty with the landfill emission estimates is the characterization of the current and future landfill population. The characterization is based on an EPA survey of a small number of landfills rather than landfill-specific information from the population of U.S. landfills. For example, the analysis simulates the opening and closing of landfills, waste disposal over time, and the installation of landfill gas-to-energy recovery systems. In addition, the baseline emission estimates do not include emission reductions associated with landfills that flare their gas and do not have landfill gas-to-energy recovery systems. Such data are not currently available, but EPA is working to develop it. Thus, the analysis underestimates current emission reductions.

2.0 Emission Reductions

Two approaches exist for reducing methane emissions from landfills: (1) recovering and either flaring or using landfill methane for energy; and (2) modifying waste management practices to reduce waste disposal in landfills, through recycling and other alternatives. The first approach is an increasingly common practice as demonstrated by the over 250 landfills that currently collect and use their gas for energy (Kruger, et al., 1999). This report focuses on evaluating the cost-effectiveness of methane recovery for energy. The second approach is not assessed, although expected changes in MSW disposal rates due to recycling are reflected in the emission projections.

The costs and benefits of emission reductions (through the implementation of gas recovery projects) at landfills not subject to the Landfill Rule are analyzed for the years 2000, 2010, and 2020. In addition, a marginal abatement curve (MAC) is constructed showing a schedule of emission reductions that could be obtained at increasing values for methane. The analysis considers the value of abated methane as the sum of its value as a source of energy, i.e., natural gas and electricity, and as an emission reduction of a greenhouse gas (GHG).

A description of the various technologies and practices that can reduce methane emissions is provided in this section. In addition, this section also presents the cost

Exhibit 2-6: Projected Baseline Methane Emissions from Landfills (MMTCE)

Activity	2000	2005	2010	2015	2020
MSW Landfilling	83.4	87.5	87.0	82.5	76.1
Oxidation from MSW	(8.3)	(8.8)	(8.7)	(8.2)	(7.6)
Industrial Waste Landfilling	5.3	5.5	5.5	5.2	4.8
Total Emissions (without the Landfill Rule)	**80.3**	**84.3**	**83.8**	**79.4**	**73.3**
Landfill Rule Emission Reductions	(28.8)	(30.3)	(31.8)	(32.0)	(32.2)
Projected Baseline Emissions	**51.4**	**54.0**	**52.0**	**47.4**	**41.1**

Totals may not sum due to independent rounding.

analysis for evaluating emission reductions as well as the MAC for emission reductions in 2010. Finally, the uncertainties and limitations associated with EPA's reduction estimates are described.

2.1 Technologies for Reducing Methane Emissions

Gas collection, by vertical wells and horizontal trenches, typically begins after a portion of a landfill, called a cell, is closed. Vertical wells are most commonly used for gas collection, while trenches are sometimes used in deeper landfills, and may be used in areas of active filling. The collected gas is routed through lateral piping to a main collection header. Ideally, the collection system should be designed so that an operator can monitor and adjust the gas flow if necessary. Once the landfill methane is collected, it can be used in a number of ways, including electricity generation, direct gas use (injection into natural gas pipelines), powering fuel cells, or compression to liquid fuel. EPA's analysis focuses on the first two options, summarized below.

Electricity Generation. Almost 80 percent of landfill electric power generation projects use reciprocating internal combustion (IC) engines (Kruger, et al., 1999). IC engines are relatively inexpensive, efficient, and appropriate for smaller landfills where gas flows are between 625 thousand cubic feet per day (Mcf/day) to 2,000 Mcf/day at 450 British thermal units per cubic feet (Btu/ft^3) (Jansen, 1992). This gas flow and energy content is sufficient to produce one to three megawatts (MW) of electricity per project (Thorneloe, 1992).

Direct Gas Use. Landfill gas is used as a medium-Btu fuel for boilers or industrial processes, such as drying operations, kiln operations, and cement and asphalt production. In these projects, the gas is piped directly to a nearby customer where it is used as a replacement or supplementary fuel. If medium-Btu fuel is sold to a customer that is in close proximity to the landfill, ideally within five miles, usually only minimal gas processing is required. Ideal gas customers have a steady, annual gas demand compatible with a landfill's gas flow.

The analysis does not assess the following technologies for reducing emissions because they are typically more costly than electricity generation or direct gas use projects and the extent of their use in the landfill gas-to-energy industry is difficult to predict.

- **Reduced Landfilling.** Landfilling is reduced through recycling, waste minimization, and waste diversion to alternative treatment and disposal methods, such as composting and incineration. The U.S. is making significant efforts at both the federal and state level to reduce landfilling. Although the analysis does not evaluate the cost-effectiveness of reduced landfilling, the baseline methane emission estimates include the anticipated impacts of changes in waste management practices.
- **Turbine Generators**. Similar to IC engines, turbine generators generate electricity. While turbines are often better for large projects in excess of three MW, IC engines are more cost-effective for the sizes of projects examined in this analysis. Because the largest landfills in the U.S. are expected to recover and combust their gas under the Landfill Rule by the year 2000, this analysis focuses on the smaller landfills for which IC engines are preferred.
- **Natural Gas Pipeline Injection.** Landfill gas can be sold to the natural gas pipeline system once it has met certain process and treatment standards. This option is appropriate in limited cases, such as when very large quantities of gas are available.
- **Liquid Vehicle Fuel.** Landfill gas is processed into liquid vehicle fuel for use in trucks hauling refuse to a landfill.
- **Flare-Only Option.** Several U.S. landfills have implemented flare systems without energy recovery systems. These landfills are either required to flare their landfill gas or they flare to control odor and gas migration. EPA's analysis did not address flaring as a stand-alone option.

2.2 Cost Analysis of Emission Reductions

EPA evaluates both electricity generation and direct gas use projects for landfills not subject to the Landfill Rule.

A project is considered cost-effective when the value for its abated methane (revenue) is equal to or greater than the project's cost. The analysis evaluates the cost-effectiveness over a range of comparable values for abated methane in terms of electricity prices (dollars per kilowatt-hour or $/kWh), gas prices (dollars per million Btu or $/MMBtu), and emission reduction values (dollars per metric ton of carbon equivalent or $/TCE).

EPA first evaluates electricity generation projects for each modeled landfill and determines if such a project is cost-effective. For those landfills where electricity generation projects are not cost-effective, the analysis then evaluates whether direct gas use projects are cost-effective at an equivalent value in gas-price terms, $/MMBtu. For landfills that cannot cost-effectively implement either project, methane emission reductions are zero. The analysis is repeated at a range of values for abated methane and the results of the analysis are used to construct a MAC.

Both electricity and direct gas use projects require a gas collection system and involve capital and operation and maintenance (O&M) costs for various project components. Capital costs for a collection system include the purchase and installation of extraction wells, lateral well connections, a header system, a gas mover system, and a condensate handling system. Annual O&M figures include labor costs of two to three person-years and indirect costs including overhead, insurance, and administration. The expected cost of replacing components of the collection system are small relative to the overall cost of the collection and recovery and utilization systems. Additional component costs for electricity and direct gas use are described in more detail below.[5]

2.2.1 Electricity Generation

The cost analysis for landfill gas-to-electricity projects consists of the following three steps.

Step 1: Define Project Components. Each project includes a collection system, flare system, and electricity production system. Appendix II, Exhibit II-5 details the factors used to estimate project costs.

- **Collection System.** As discussed above, all gas recovery projects start with a gas collection system. These costs are driven primarily by the amount of WIP. Gas collection efficiency is assumed to be 75 percent of emitted methane.
- **Flare System.** All gas recovery projects require a flare system because excess gas may need to be flared at any time. Peak gas flow from the collection system drives these costs.
- **Electricity Production.** Electricity production requires a variety of equipment including: compressors to move the gas, a prime mover (IC engines in this case), an electric generator, an interconnect with the local grid, and a monitoring and control system.

Total costs equal the sum of the components listed above. Exhibit 2-7 lists estimated costs for projects of various sizes as defined by a landfill's WIP and the electricity production capacity in MW. The size of each generator is based on the maximum gas flow rate during the life of the project. In most cases the gas produced is less than the maximum capacity of the engine generator. No downtime is assumed since the unit is modeled to run at less than capacity during most of the project's lifetime.

Step 2: Estimate Project Revenue. EPA estimates revenues for a range of electricity prices and values of abated methane. The rate at which landfill owners sell electricity depends on local and regional electric power market conditions, and often varies by time of day and season. This analysis uses a market price of $0.04/kWh (1996 US$) as a representative figure.[6] The analysis does not consider additional revenues from state and federal incentives for landfill gas-to-energy projects. EPA estimates the annual total electricity production from the project based on the amount of gas produced and collected each year.

For modeling purposes, electricity prices are converted to $/TCE using methane's Global Warming Potential (GWP) of 21 and the heat rate (10,000 Btu/kWh) of the engine-generator.[7]

Exhibit 2-7: Electricity Generation – Example Cost Estimates by Project Size							
Size		Collect and Flare System		IC Engine/Generator		Total Costs	
WIP (MT 000)	(MW)	Capital ($000)	O&M ($000)	Capital ($000)	O&M ($000)	Capital ($000)	O&M ($000)
318	0.50	$272	$61	$693	$66	$965	$127
476	0.75	$353	$64	$1,011	$99	$1,364	$163
635	1.00	$428	$67	$1,322	$131	$1,749	$199
953	1.50	$568	$73	$1,927	$197	$2,495	$270
1,271	2.00	$699	$78	$2,517	$263	$3,216	$341
1,127	3.00	$654	$77	$3,957	$394	$4,611	$471
2,918	5.00	$1,310	$103	$6,000	$657	$7,310	$760

All estimates are in 1996 dollars.

Step 3: Evaluate Cost-Effectiveness. EPA assesses the cost-effectiveness of implementing a project at each landfill using a benefit-cost analysis with the costs and revenues described above, and the cost parameters listed in Exhibit 2-8. Electricity production is assumed to take place for 20 years, with an option at the end of that period to replace the engines and generate electricity for another 20 years. If the net present value (NPV) of the project is zero or positive, the project is considered cost-effective.

Exhibit 2-8: Financial Assumptions for Emission Reduction Analysis

Parameter	Value
Discount Rate	8 percent real
Depreciation Period	10 years
Marginal Tax Rate	40%
Duration of Project	Electricity: 20 years; Direct Gas Use: 15 years
Collection Efficiency	75%

2.2.2 Direct Gas Use

EPA evaluates the cost-effectiveness of direct gas use projects at landfills not subject to the Landfill Rule and for which electricity generation projects are not cost-effective. The evaluation is based on the three steps indicated below.

Step 1: Define "Model" Project Components. The costs of a model project include a gas collection and flare system, gas treatment, gas compression to 50 pounds per square inch (psi), and a five-mile gas pipeline to a customer. For each landfill size, EPA estimates the capital and O&M costs for each component using the unit costs presented in Appendix II, Exhibit II-6 and the cost parameters in Exhibit 2-8. The unit costs are taken from the Energy Project Landfill Gas Utilization Software (E-PLUS), an EPA-distributed software used to evaluate the cost-effectiveness and feasibility of landfill gas-to-energy projects (EPA, 1997b).[8] Exhibit 2-9 presents the costs and break-even gas prices as defined by a landfill's WIP.

EPA estimates the break-even gas prices ($/MMBtu) required to support a "model" direct gas use project for landfills with a WIP ranging from 50,000 to 11,000,000 MT. The break-even gas price is the value required to produce a zero NPV over the 15-year life of the project.

Step 2: Define Methane Abatement Values. A market price of gas of $2.74/MMBtu (1996 US$) is used in the analysis. This price is 80 percent of the national average industrial natural gas price of $3.42/MMBtu (EIA, 1997). The national average price is discounted by 20 percent to account for the fact that the landfill gas is a medium-grade gas. EPA converts gas prices, in $/MMBtu, to methane abatement values, in $/TCE, using methane's GWP of 21 and a Btu content of 1,000 Btu/ft^3 for methane.[9]

In order to compare direct gas use with electricity generation projects and combine them on the same MAC, gas prices are aligned with the electricity prices based on equivalent emission reductions values. For example, 150 percent of the market electricity price or $0.06/kWh, is

Exhibit 2-9: Direct Gas Use Cost Estimates by Project Size											
WIP (MT 000)	Collection and Flare		Compression		Gas Treatment		Pipeline		Total		Break-Even Gas Price ($/MMBtu)
	Capital ($000)	O&M ($000)	Capital ($000)	O&M ($000)	Capital ($000)	O&M ($000)	Capital ($000)	O&M ($000)	Capital ($000)	O&M ($000)	
50	$124	$52.0	$3.3	$12.6	$3.25	$10.0	$924	$18.5	$1,054	$93	$55.03
100	$156	$54.5	$6.6	$13.3	$3.31	$10.0	$924	$18.5	$1,090	$96	$27.72
200	$215	$56.0	$13.4	$14.6	$3.42	$10.0	$924	$18.5	$1,156	$99	$14.92
300	$269	$57.3	$20.1	$15.9	$3.53	$10.0	$924	$18.5	$1,216	$102	$10.36
400	$319	$59.8	$26.7	$17.2	$3.64	$10.0	$924	$18.5	$1,273	$105	$8.11
500	$364	$62.3	$33.4	$18.5	$3.74	$10.1	$924	$18.5	$1,325	$109	$6.74
600	$412	$64.6	$40.1	$19.8	$3.85	$10.1	$924	$18.5	$1,380	$113	$5.83
700	$458	$68.0	$46.8	$21.1	$3.96	$10.1	$924	$18.5	$1,432	$118	$5.20
800	$500	$68.6	$53.5	$22.3	$4.07	$10.1	$924	$18.5	$1,481	$120	$4.67
900	$540	$70.0	$60.2	$23.6	$4.18	$10.1	$924	$18.5	$1,529	$122	$4.27
1,000	$581	$70.8	$129.0	$37.0	$5.30	$10.2	$924	$18.5	$1,639	$136	$2.16
11,000	$3,522	$189.0	$603.0	$129.0	$19.00	$10.9	$924	$18.5	$5,068	$347	$1.35

Estimates are an average for arid and non-arid conditions and represent 1996 dollars.

Source: EPA, 1997b.

paired with 150 percent of the market gas price or $4.10/MMBtu.

Step 3: Evaluate Cost-Effectiveness. For direct use projects, EPA estimates the break-even WIP for each gas price by interpolation; as shown in Exhibit 2-9. The analysis categorizes a landfill as implementing a direct gas use project when its methane-producing WIP is equal to or greater than the break-even WIP for a given gas price.

Emission reductions from direct gas use projects equal the gas that is collected and combusted. EPA assumes that only 75 percent of these cost-effective direct gas use projects are implemented to account for the uncertainty in identifying an energy end-user.

As energy prices increase, the break-even WIP declines allowing smaller landfills to cost-effectively invest in direct gas use projects. This trend is important because while the Landfill Rule is reducing emissions from larger U.S. landfills, many small landfills exist where cost-effective reductions also can be achieved.

2.3 Achievable Emission Reductions and Marginal Abatement Curve

The result of this analysis is an assessment of the cost-effectiveness of two types of landfill gas recovery and use projects: electricity generation and direct gas use. For 2010, EPA estimates that U.S. landfills could reduce methane emissions by up to 10.5 MMTCE (1.8 Tg) through implementing these types of cost-effective projects at energy market prices (1996 US$). These potential reductions are without any additional value for abated methane in terms of $/TCE. If emission reduction values are added to the energy market prices, greater methane reductions are achieved. For example, EPA's analysis indicates that with a value of $20/TCE for abated methane added to the energy market price, U.S. reductions could reach 20.2 MMTCE (3.5 Tg) in 2010.

Exhibit 2-10 shows the amounts of abated methane incremental to the Landfill Rule that can be cost-effectively achieved for a range of comparable values of abated methane through $200/TCE. For some landfills, both electricity and direct gas use projects are cost-effective. However, for modeling purposes, EPA assumes that these landfills implement an electricity generation project. Consequently, the eligible landfills for direct use projects indicated in Exhibit 2-10 represent

Exhibit 2-10: Schedule of Emission Reductions Over and Above the Landfill Rule by Price in 2010

	Electricity Production[a]				Direct Gas Use				Total Emission Reductions		
Value of Carbon Equiva-lent ($/TCE)	Price ($/kWh)	Break-Even WIP (MT)	Eligible Landfills	Incremental Reductions (MMTCE)	Price ($/MMBtu)	Break-Even WIP (MT)	Eligible Landfills	Incremental Reductions (MMTCE)	Cumulative Reductions (MMTCE)	% of base-line	Label on MAC[b]
(10)	0.03	Infeasible	0	0.00	1.64	7,436,565	0	0.00	0.00	0%	N/A[c]
(6)[d]	0.03	Infeasible	0	0.00	2.05	2,330,467	114	3.48	3.48	7%	A
0	0.04	2,900,493	64	1.98	2.74	972,739	498	5.09	10.55	20%	B
10	0.05	538,232	773	11.25	3.84	920,668	106	(7.35)[e]	14.44	28%	C
20	0.06	273,860	1,919	6.96	4.94	749,467	7	(1.16)	20.23	39%	D
30	0.07	177,368	2,319	1.27	6.03	576,422	0	(0.05)	21.45	41%	E
40	0.08	129,583	2,505	0.29	7.13	468,324	0	0.00	21.75	42%	F
50	0.09	101,309	2,615	0.11	8.23	393,655	0	0.00	21.85	42%	G
75	0.12	66,064	2,685	0.05	10.98	283,477	0	0.00	21.90	42%	H
100	0.15	48,086	2,720	0.02	13.73	222,143	0	0.00	21.91	42%	I
125	0.18	Negligible	2,720	0.00	16.48	182,893	0	0.00	21.91	42%	J
150	0.20	Negligible	2,720	0.00	19.23	152,742	0	0.00	21.91	42%	K
175	0.23	Negligible	2,720	0.00	21.98	134,836	0	0.00	21.91	42%	L
200	0.26	Negligible	2,720	0.00	24.73	118,155	0	0.00	21.91	42%	M

[a] Includes emission reductions for landfills at which either a gas or an electricity project is modeled as cost-effective. By default, the analysis selects electricity projects over gas projects where both are cost-effective.

[b] Point on marginal abatement curve (see Exhibit 2-11) indicating minimum break-even WIP for electricity and direct gas use projects.

[c] Although cost-effective reductions at landfills of this size exist, they are subject to the Landfill Rule (over 2.5 MMT WIP), and thus, are not counted as emission reductions in this analysis.

[d] The potential emission reductions associated with the modeled prices of $2.05/MMBtu or -$6/TCE are "below the line" reductions in carbon equivalent terms.

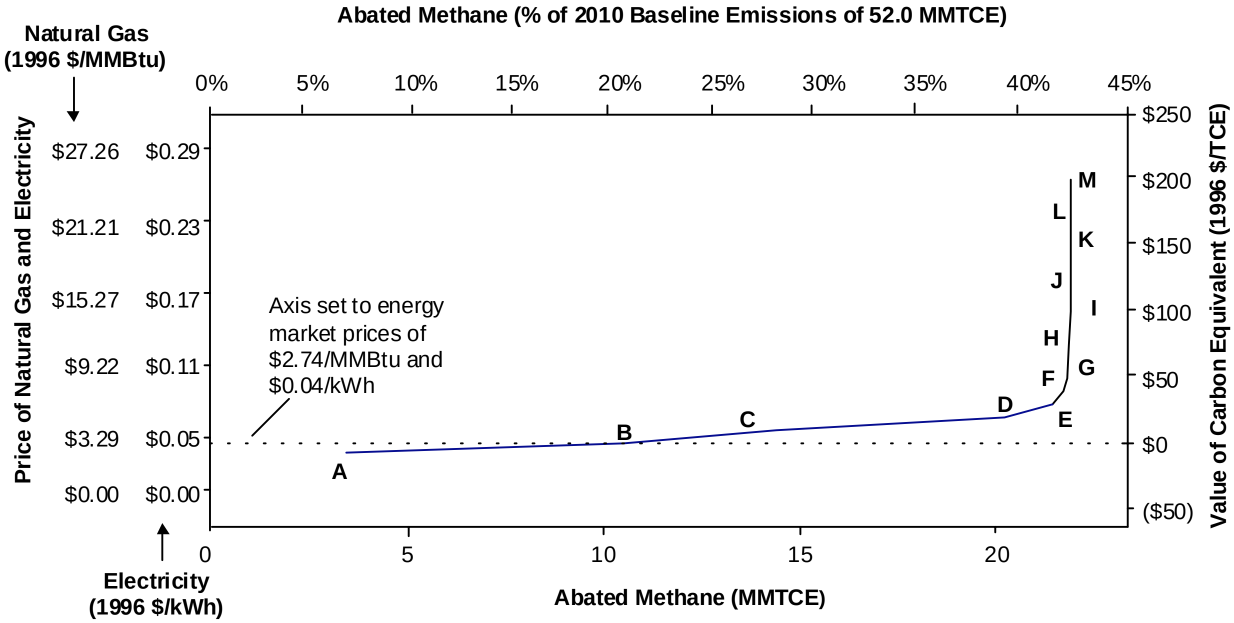
[e] Negative incremental reductions indicate that emission reductions attributed to gas projects at lower prices are modeled as electricity projects at higher prices because electricity projects become cost-effective as values increase above $0/TCE.

those landfills that find only direct gas use projects cost-effective. As indicated in the exhibit, above $20/TCE, no landfills find only direct gas use cost-effective. The negative incremental reductions under the direct gas option indicate the direct use projects for which electricity production also becomes cost-effective at the higher methane values.

Exhibit 2-11 illustrates the MAC for landfill electricity generation and direct gas use projects not subject to the Landfill Rule for 2010. Exhibit 2-12 presents the cumulative emission reductions for selected values of carbon equivalent in 2000, 2010, and 2020. The MAC can similarly be called a cost or supply curve since it shows the marginal cost per emission reduction amount. Energy market prices are aligned with $0/TCE given that this price represents no additional values for abated methane and where all price signals come only from the respective energy markets. The "below-the-line" reduction amounts, with respect to $0/TCE, illustrate this dual price-signal market, i.e., energy market prices and emission reduction values.

Each point on the MAC represents the quantity of methane that is cost-effectively abated at a given energy price combination and emission reduction value. In addition, each point on the graph reflects the minimum break-even WIP between electricity projects and direct gas use projects. The minimum break-even WIP for electricity generation and direct gas use projects determines the size of the smallest landfill for which a landfill gas-to-energy project is cost-effective. As shown in the exhibit, emis-

Exhibit 2-11: Marginal Abatement Curve for Methane Emissions from Landfills in 2010



sion reductions approach their maximum at approximately $36/TCE which is comparable to $0.08/kWh and $6.69/MMBtu.

The analysis indicates that at and below energy market prices, only direct gas use projects are cost-effective and electricity production projects do not contribute to emission reductions. This modeled result, however, underestimates the potential for emission reductions since many landfills are currently implementing electricity projects. Many of these landfills take advantage of state and federal incentives that are not reflected in this analysis.

Emission reductions from both landfills impacted by the Landfill Rule and "non-Rule" landfills reach approximately 65 percent of total MSW methane emissions, only 10 percent below the maximum possible given the estimated recovery efficiency of 75 percent. The analysis assumes that small and industrial landfills, which were not evaluated for purposes of the MAC, continue to emit methane. Therefore total emission reductions do not approach the 75 percent maximum.

Exhibit 2-12: Emission Reductions at Selected Values of Carbon Equivalent in 2000, 2010, and 2020 (MMTCE)

	2000	2010	2020
Baseline Emissions	51.4	52.0	41.1
Cumulative Reductions			
at $0/TCE	11.0	10.5	7.6
at $10/TCE	14.1	14.4	10.1
at $20/TCE	18.2	20.2	13.9
at $30/TCE	19.7	21.5	15.0
at $40/TCE	20.1	21.7	15.5
at $50/TCE	20.5	21.9	15.7
at $75/TCE	21.2	21.9	15.8
at $100/TCE	21.4	21.9	15.9
at $125/TCE	21.5	21.9	15.9
at $150/TCE	21.6	21.9	15.9
at $175/TCE	21.6	21.9	15.9
at $200/TCE	21.7	21.9	15.9
Remaining Emissions	29.8	30.1	25.2

2.4 Reduction Estimate Uncertainties and Limitations

Most of the uncertainties associated with emission reduction estimates relate to the landfill population uncertainties described in the first section. Additional data are needed to improve the basis for characterizing the landfill population and the potential to collect and use gas cost-effectively at each landfill.

Other uncertainties involve landfill gas recovery technologies and the costs for recovering landfill gas. For both electricity and direct gas use projects, EPA estimates the costs using aggregate cost factors and a relatively simple set of landfill characteristics. Costs vary depending on the depth, area, WIP, and waste materials for each landfill. Uncertainty is associated with the electricity analysis because EPA bases costs on a representative WIP. Although the costs for direct gas use projects account for depth, area, and WIP (along with unit costs), they are only representative of average costs.

The price at which landfills sell electricity also is an important driver in the analysis. At higher rates, more landfills find it cost-effective to implement electricity projects. In addition, efforts to reduce landfilling, including waste management policies that go beyond existing programs, are potentially cost-effective in further reducing future methane emissions. The costs and benefits of such alternative waste management policies are not included in this assessment.

Lastly, project revenues only reflect market prices of electricity and gas and do not reflect state and federal incentives or subsidies. Incorporating these currently available incentives in the analysis would result in additional cost-effective emission reductions.

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4.0 Explanatory Notes

[1] Climate Change Action Plan or CCAP reductions are achieved as a result of voluntary industry actions. For example, under CCAP, EPA created the joint EPA-industry Landfill Methane Outreach Program (LMOP). Under this program, landfill industry partners undertake cost-effective efforts to reduce methane emissions from landfills. This analysis does not evaluate specific emission reductions associated with LMOP, rather, the analysis focuses on projected cost-effective emission reductions at landfills not impacted by the Landfill Rule. EPA expects that 40 percent of the cost-effective emission reductions available in 2010 will be taken as a result of LMOP.

[2] BioCycle includes construction and demolition (C&D) debris in their estimates of waste generation. However, the definition of municipal solid waste (MSW) is not uniform for each state in BioCycle's survey. Some states report C&D because many of their landfills accept waste from a variety of sources (BioCycle 1998). Although the waste estimates prior to 1990 exclude C&D waste, EPA did not adjust the BioCycle estimates due to the inconsistent definition of MSW for each state.

[3] Equations for calculating methane generation as a function of methane generating waste-in-place (WIP):

Methane Generating WIP	Methane Emissions (MT/year)
Less than or equal to 0.04 10^6 MT	0
Greater than 0.04 10^6 MT and less than or equal to 2.0 x 10^6 MT	7.43 x (WIP/10^6) x Conversion Factor[a] x Scale[b]
Greater than 2.0 x 10^6 MT	(8.22 + 5.27 x (WIP/10^6)) x Conversion Factor[a] x Scale[b]

[a] Conversion Factor (m^3/min to MT/year) = (365 days/yr) x (24 hrs/day) x (60 min/hr) x (662 g CH_4/m^3) x (MT/10^6g).

[b] The landfills in the landfill population data set are weighted in order to adjust the sample landfill population to the national level. The weighted numbers are 2, 3, and 7. Hence, a simulated landfill may account for 2, 3, or 7 landfills (Scale = 2, 3, or 7).

These equations are based on a survey of 85 landfills with a WIP ranging from 1.2 million MT to 30 million MT. The third equation is based on a regression analysis of the survey results. The second equation is based on the average rate of methane generation per unit of WIP.

[4] EPA conducts the emission analysis using a range of high and low average NMOC concentration values based on the number of landfills expected to trigger under the Landfill Rule by 2000. EPA calibrates the model by adjusting the average methane NMOC concentration to 500 parts per million by volume in order to simulate 350 existing and approximately 50 new landfills that will trigger under the Landfill Rule by 2000.

[5] EPA assumes that capital and O&M costs are constant for the 30-year time horizon and do not change due to development of more efficient and less costly technologies.

[6] The electricity rates in the U.S. that landfills are able to obtain for their generation, i.e., electric buyback rates, vary depending on several factors, including: the cost of system power on the grid (peak or off-peak), transmission (and in some cases distribution charges), region, and pricing. In addition, renewable power commands a premium that historically has been in the form of regulated buy-back rates or tax credits. More recently it has taken the form of green power premiums. Historically, under a regulated environment, landfill gas power projects have received electric buyback rates ranging from $0.02/kWh to $0.10/kWh, averaging about $0.06/kWh (EPA, 1996). For this study, EPA assumes a price of $0.04/kWh. This value represents the price of electricity close to distribution systems and receiving a renewable energy premium.

[7] Equation to calculate the equivalent electricity price for a given value of carbon equivalent:

$$\frac{\$}{TCE} \ x \ \frac{10^6 \ TCE}{MMTCE} \ x \ \frac{5.73 \, MMTCE}{Tg \ CH_4} x \ \frac{Tg}{10^{12} \ g} \ x \ \frac{19.2 \ g \ CH_4}{ft^3 \ CH_4} \ x \ \frac{ft^3}{1{,}000 \ Btu} \ x \ \frac{10{,}000 \ Btu}{kWh} = \frac{\$}{kWh}$$

Where: 5.73 MMTCE/Tg CH_4 = 21 CO_2/CH_4 x (12 C / 44 CO_2)
Density of CH_4 = 19.2 g/ft^3
Btu content of CH_4 = 1,000 Btu/ft^3
Heat rate of IC Engine = 10,000 Btu/kWh

[8] The costs for electricity production and direct gas use are based on different algorithms. Both options include collection and flare project components because some amount of gas will be flared. The landfill depth and area, and the collection system variable O&M costs are adjusted in E-PLUS so that the direct gas use collection capital and O&M costs are calibrated within five to ten percent of the electricity project collection system costs.

[9] Equation to calculate the equivalent gas price for a given value of carbon equivalent:

$$\frac{\$}{TCE} \ x \ \frac{10^6 \ TCE}{MMTCE} \ x \ \frac{5.73 \, MMTCE}{Tg \ CH_4} x \ \frac{Tg}{10^{12} \ g} \ x \ \frac{19.2 \ g \ CH_4}{ft^3 \ CH_4} \ x \ \frac{ft^3}{1{,}000 \ Btu} \ x \ \frac{10^6 \ Btu}{MMBtu} = \frac{\$}{MMBtu}$$

Where: 5.73 MMTCE/Tg CH_4 = 21 CO_2/CH_4 x (12 C / 44 CO_2)
Density of CH_4 = 19.2 g/ft^3
Btu content of CH_4 = 1,000 Btu/ft^3

3. Natural Gas Systems

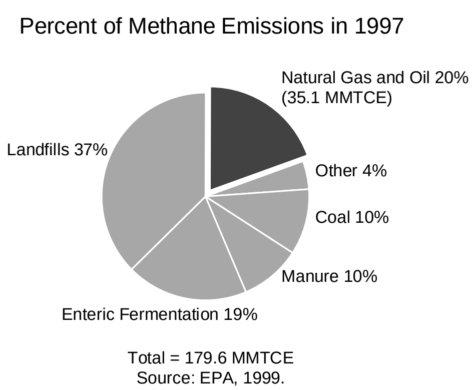
Summary

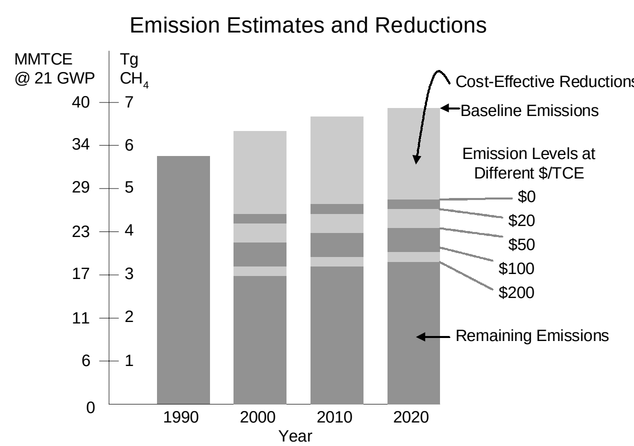
EPA estimates 1997 U.S. methane emissions to be 33.5 MMTCE (5.8 Tg) from natural gas systems and 1.6 MMTCE (0.3 Tg) from oil systems, which together accounted for approximately 20 percent of total U.S. anthropogenic methane emissions (EPA, 1999). In 1997, the U.S. produced 18.9 trillion cubic feet (Tcf) (364 Tg) and consumed 22.0 Tcf (422 Tg) of natural gas (the balance was imported), which is 95 percent methane (EIA, 1999). Natural gas is produced at thousands of gas and oil wells, purified at hundreds of processing plants, transported through a continental network of pipelines, and delivered to millions of customers. Natural gas consumption is divided among industrial (44 percent), residential (25 percent), commercial (16 percent), and electric utility (15 percent) uses (EIA, 1998). Methane is emitted to the atmosphere through leaks and by accidental and deliberate venting of natural gas during normal operations, i.e., production, processing, transmission, and distribution. Because natural gas is often found in conjunction with oil, its production and processing also emits methane.

EPA expects baseline emissions from natural gas systems to grow as natural gas consumption increases. The U.S. Department of Energy anticipates U.S. gas consumption will increase 1.6 percent each year between 1996 and 2020, leading to annual consumption of about 32 Tcf (618 Tg) by 2020. Demand is expected to increase in all sectors, especially from electric utilities (EIA, 1998). However, equipment turn-over along with new and more efficient technologies will result in a methane emission growth rate that is lower than the growth in consumption. EPA estimates that methane emissions from natural gas systems will reach 37.9 MMTCE (6.6 Tg) by 2010, excluding possible Climate Change Action Plan (CCAP) reductions.

CCAP's Natural Gas STAR Program, a voluntary EPA-industry partnership, has identified cost-effective technologies and practices that can reduce methane emissions. In 2010, EPA estimates that up to 10.1 MMTCE (1.8 Tg) of reductions are cost-effective at energy market prices (in 1996 US$) or $0/TCE, as Exhibit 3-1 shows. Methane emissions could be reduced below 1990 emissions of 32.9 MMTCE (5.7 Tg) for natural gas systems if these cost-effective technologies and practices are thoroughly implemented. More reductions could be achieved with the addition of higher carbon equivalent values.

Exhibit 3-1: U.S. Methane Emissions from Natural Gas Systems (MMTCE)





1.0 Methane Emissions from Gas and Oil Systems

This section summarizes the sources of emissions from oil and gas systems and describes EPA's methodology for estimating these emissions. The section also presents EPA's emission estimates and forecast.

1.1 Emission Characteristics

Natural Gas. The natural gas sector is comprised of four major sub-sectors: production, processing, transmission, and distribution. Methane emissions occur during normal operations in all sub-sectors as described in Exhibit 3-2. During production, gas exits wells under very high pressure, often greater than 1,000 pounds per square inch (psi). The gas is routed to dehydrators, where water and other liquids are removed, and then to small-diameter gathering lines for transport to either processing plants or directly into interstate pipelines. Processing plants further purify the gas by removing natural gas liquids, sulfur compounds, particulates, and carbon dioxide. The processed gas, which is about 95 percent methane, is then injected into large-diameter transmission pipelines where it is compressed and transported to distribution companies, often hundreds of miles away. Distribution companies take the high-pressure gas (averaging 300 psi to 600 psi) and reduce the pressure to as low as a few pounds or even ounces per square inch for delivery to homes, businesses, and industry.

From wellhead to end user, the gas moves through hundreds of valves, processing mechanisms, compressors, pipes, pressure-regulating stations and other equipment. Whenever the gas moves through valves and joints under high pressure, methane can escape to the atmosphere. In many instances, gas is vented to the atmosphere as part of normal operations. For example, a major source of vented emissions are pneumatic devices, that operate valves using pressure in the system and bleed small amounts of gas to the atmosphere when valves are opened and closed. Another example of venting is the common industry practice of shutting down a compressor and purging the gas in the compression chamber to the atmosphere.

Oil. Most oil wells produce some natural gas, which is usually dissolved in the crude oil stream. Methane and other volatile hydrocarbon compounds dissolved in oil escape the solution as the oil is processed and stored in

Exhibit 3-2: Sources of Methane Emissions from Oil and Gas Activities (1997)

Industry Sector	Natural Gas Industry Sources of Emissions	Percent of Total and Amount	Crude Oil Industry Sources of Emissions	Percent of Total and Amount
Production	Wellheads, dehydrators, separators, gathering lines, and pneumatic devices	25% 8.4 MMTCE or 1.5 Tg	Wellheads, separators, venting and flaring, other treatment equipment	49% 0.7 MMTCE or 0.13 Tg
Processing	Compressors and compressor seals, piping, pneumatic devices, and processing equipment	12% 4.1 MMTCE or 0.7 Tg	Waste gas streams during refining	2% 0.1 MMTCE or 0.01 Tg
Transmission & Storage	Compressor stations (blowdown vents, compressor packing, seals, valves), pneumatic devices, pipeline maintenance, accidents, injection/withdrawal wells, pneumatic devices, and dehydrators	37% 12.4 MMTCE or 2.2 Tg	Transportation tanker operations, crude oil storage tanks	48% 0.7 MMTCE or 0.13 Tg
Distribution	Gate stations, underground non-plastic piping (cast iron mainly), and third party damage	26% 8.6 MMTCE or 1.5 Tg	Not applicable	
Total		33.5 MMTCE or 5.8 Tg		1.6 MMTCE or 0.27 Tg

Totals may not sum due to independent rounding.

Source: EPA, 1999.

holding tanks before being transported off the well site. Depending on how much gas is associated with the oil, field operators may install equipment to capture and sell much of the gas.

1.2 Emission Estimation Method

The method for estimating emissions from natural gas systems is different from the method for oil systems. These methods are described below.

1.2.1 Natural Gas System Emissions

EPA relies on three types of data to generate the annual methane emission inventory: emission factors, activity factors, and activity factor drivers. These elements are described below:

- **Emission Factors.** Emission factors describe the rate of methane emissions measured or estimated at a piece of equipment or facility during normal operations. The source of the emission factors is a detailed study, *Methane Emissions from the Natural Gas Industry*, sponsored by EPA and the Gas Research Institute (EPA/GRI, 1996). Based on this study, EPA has developed emission factors for about 100 sources within the natural gas industry, e.g., gas well equipment, pipeline compressors and equipment, and system upsets.
- **Activity Factors.** Activity factors are statistics on pieces of equipment or facilities that are associated with given emission factors. Examples include number of wells, miles of pipe of a similar type and operating regime, or hours of operation by compressor type. Activity factors are critical for extrapolating from a limited set of emission measurements at individual pieces of equipment to larger facilities and ultimately to the entire industry. The EPA/GRI study developed activity factors corresponding to the emission factors. Additional sources of activity data are publications from the Energy Information Administration (EIA), American Petroleum Institute (API), American Gas Association (AGA), and others.
- **Activity Factor Drivers.** Activity factor drivers are used to adjust the magnitude of activity factors from year to year consistent with gas market and industry changes in order to update or forecast emission estimates. Examples of drivers include gas sales, miles of distribution main, number of wells, and hours of compressor operations. In some cases, the relationship between activity factor drivers and emission estimates may be indirect. For example, to estimate emissions from glycol dehydrators, EPA first estimates an average number of dehydrators per well. The number of wells, i.e., the activity factor driver, is updated annually and used to update emissions from glycol dehydrators. EPA obtains activity driver data from EIA, API, AGA, and other industry sources.

Appendix III, Exhibits III-1 and III-2 summarize the emission factors, activity factors, and activity factor drivers used in this analysis.

The emission inventory estimate begins with a functional segmentation of the industry and the activities that occur within each segment: production, processing, transmission and storage, and distribution (See Exhibit 3-2). For each segment, EPA estimates emissions by multiplying emission factors (EF) by associated segment-wide activity factors (AF) as shown in this formula:

$$\text{Total emissions} = \text{EF x AF}$$

The multi-volume EPA/GRI report, *Methane Emissions from the Natural Gas Industry*, analyzes emissions from all gas industry segments for the year 1992 and sums these emissions. EPA uses this estimate for the 1992 national estimate. For the period 1990 to 1997, EPA uses the activity factor drivers to adjust the 1992 estimate to reflect annual changes in the industry.

While EPA annually adjusts activity factors to reflect year-to-year changes in the industry, emission factors are treated differently. For the period 1990 to 1995, the emission factors are held constant. However, EPA assumes that a gradual improvement in technology and practices along with equipment replacement will lower emission factors by a total of five percent between 1995 and 2020.

1.2.2 Oil Industry Emissions

The current estimates of methane emissions from the oil industry depend on emission factors and activity factors based on broad categories of activities in the oil industry and not on a detailed, bottom-up approach as used for the natural gas sector estimates. The major oil sector activities are summarized in Exhibit 3-3.

Production Field. Emission factors for oil production are taken from *Anthropogenic Methane Emissions in the United States: Estimates for 1990, Report to Congress* (EPA, 1993). Emission factors are multiplied by updated activity factors (for the portion of oil wells that do not produce associated gas) as reported by API (1997).

Crude Oil Storage. Baseline emissions from crude oil storage are from Tilkicioglu and Winters (1989), who developed emission factor estimates by analyzing a model tank battery facility. These emission factors are applied to published crude oil storage data to estimate total emissions across the industry. Crude oil storage data are obtained from the Department of Energy (EIA, 1991-97).

Refining Waste Gas Streams. Tilkicioglu and Winters estimated national methane emissions from waste gas streams based on measurements at ten refineries. These data were extrapolated to total U.S. refinery capacity to estimate total emissions from waste gas streams for 1990. To estimate emissions for 1991 to 1996, the 1990 emission estimates were scaled using updated data on U.S. refinery capacity (EIA, 1991-96, 1997).

Transportation. EPA uses proxies to estimate emissions from crude tanker operations. For domestic crude, the estimate is for Alaskan crude offloaded in the continental U.S.; for imports, the estimate is for the total imported less imports from Canada. An emission factor from Tilkicioglu and Winters (1989) based on the methane content of hydrocarbon vapors emitted from crude oil is multiplied by the crude oil tanker handling estimates. Data on crude oil stocks, crude oil production, utilization, and imports are obtained from EIA (1991-96, 1997).

Venting and Flaring. Of the five activity categories, venting and flaring can occur at all stages of crude oil production and handling. However, for EPA methane emission estimates, venting and flaring is treated as a separate activity. Data from EIA (1991-96, 1997) indicate that venting and flaring activities have changed over time for a variety of reasons. Given the considerable uncertainty in the emission estimate for this category, and the inability to discern a trend in actual emissions, the 1990 emission estimate is used for the years 1991-1997.

EPA is revising the method for estimating methane emissions from oil production so that it will be more similar to the approach for natural gas systems. The revised approach, based on EPA and API work (1997), uses a much more disaggregated description of the crude oil production sector and activity and emission factors for specific equipment to generate the emission estimates. EPA expects to employ the new method for EPA's 1998 U.S. inventory estimates which will be published in 2000.

1.3 Emission Estimates

This section presents the current emission estimates for natural gas and oil systems and a forecast of emissions from natural gas systems.

Exhibit 3-3: Oil Industry Activities for Current Emission Estimates

Activity	Description
Production Field	Fugitive emissions from oil wells and related production field treatment and separation equipment
Crude Oil Storage	Crude oil storage tanks emit methane when oil is cycled through the tanks and hydrocarbons escape solution
Refining Waste Gas Streams	A variety of sources within refinery operations emit gas
Transportation (Tanker Operations)	Emissions occur as tankers are loaded and unloaded
Venting and Flaring	Gas that cannot be captured during production is vented or flared

1.3.1 Current Emissions and Trends

U.S. natural gas systems emitted 33.5 million metric tons of carbon equivalent (MMTCE) or 5.8 Teragrams (Tg) of methane in 1997 or about 19 percent of total U.S. anthropogenic methane emissions, as Exhibit 3-4 shows. These methane emissions from gas systems account for about one percent of the natural gas consumed in the U.S. in 1997. Emissions have increased slightly from 1990 reflecting an increase in the number of producing gas wells and distribution pipeline mileage. The increase in emissions was slowed by the emission reductions reported by Partners in EPA's Natural Gas STAR Program, one of the U.S. Climate Change Action Plan (CCAP) programs. The Natural Gas STAR Program was initiated in 1994 and works with natural gas and oil companies to identify and promote Best Management Practices (BMPs) and Partner Reported Opportunities (PROs) that reduce methane emissions cost-effectively.

From 1990 to 1997, methane emissions from oil system activities remained relatively constant at approximately 1.6 MMTCE (0.3 Tg). Currently, no CCAP program is devoted to reducing methane emissions from oil systems; however, the Natural Gas STAR Program includes BMPs that reduce methane emissions from oil systems. Exhibit 3-5 presents the emission estimates from oil systems. EPA is revising the estimation method for oil systems and expects estimates to increase.

1.3.2 Future Emissions and Trends

Natural Gas. Future emissions from natural gas systems are estimated by forecasting both emission factors and activity factors from the 1992 base year factors developed by EPA and GRI (1996). As noted above, EPA assumes that emission factors decline by a total of five percent between 1995 and 2020 as the existing stock of equipment is gradually replaced with newer and more efficient equipment.

Exhibit 3-4: Methane Emissions from Natural Gas Systems (MMTCE)

Source	1990	1991	1992	1993	1994	1995	1996	1997
Production	8.0	8.2	8.5	8.7	8.8	9.1	9.5	9.5
Processing	4.0	4.0	4.0	4.0	4.2	4.1	4.1	4.1
Transmission/Storage	12.6	12.7	12.9	12.6	12.5	12.5	12.4	12.7
Distribution	8.3	8.4	8.6	8.8	8.7	8.7	9.1	8.9
Sub-Total	**32.9**	**33.3**	**33.9**	**34.1**	**34.2**	**34.3**	**35.0**	**35.1**
CCAP Reductions[a]	–	–	–	–	(0.7)	(1.2)	(1.3)	(1.6)
Total	**32.9**	**33.3**	**33.9**	**34.1**	**33.5**	**33.2**	**33.7**	**33.5**

[a] CCAP reductions are from the Natural Gas STAR Program.
Totals may not sum due to independent rounding.
Source: EPA, 1999.

Exhibit 3-5: Methane Emissions from Oil Systems (MMTCE)

Source	1990	1991	1992	1993	1994	1995	1996	1997
Production	0.14	0.14	0.14	0.14	0.14	0.13	0.13	0.13
Crude Oil Storage	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Transportation	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.06
Refining	0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.05
Venting & Flaring	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32
Total	**1.56**	**1.56**	**1.56**	**1.56**	**1.56**	**1.55**	**1.55**	**1.55**

Totals may not sum due to independent rounding.
Source: EPA, 1999.

The principal drivers of future activity factors are the levels of gas consumption and domestic production, including the necessary expansions in industry infrastructure to meet these market levels. Using the consumption and production forecasts from the EIA's *Annual Energy Outlook* (EIA, 1998), EPA estimates the changes in infrastructure necessary to meet these consumption and production levels. Exhibit 3-6 presents forecasts of baseline methane emissions from natural gas systems through 2020. Unless actions are taken to reduce emissions, natural gas systems will emit 13 percent more methane in 2020 than in 1992, mostly due to growth in natural gas consumption and the associated growth in infrastructure. The forecast methodology is described below.

- **Production Sector.** Methane emissions from natural gas production depend on the number of wells needed for the forecast level of production and the location of the wells, since operating characteristics and equipment profiles vary by region. EPA uses the Gas Systems Analysis Model (GSAM) to estimate the number of wells. GSAM represents over 16,000 reservoirs, the entire gas transmission network and gas markets, and it identifies the number of wells needed to generate the forecast output and the location of these wells. From these forecasts, EPA estimates the emissions associated with ancillary well equipment, such as dehydrators, separators, heaters, and meters.

- **Processing Sector.** Processing and related equipment associated with emissions are scaled to domestic production.

- **Transmission and Storage Sector.** Transmission and storage emissions are related to forecasts of domestic consumption (sum of net production and imports). For compressors and their operations (hours in service per year), EPA generates emission estimates based on the pipeline throughput necessary to meet projected consumption. An increase in customers leads to an increase in pipeline mileage. Emission increases from storage operations and related equipment are associated with growth in consumption.

- **Distribution Sector.** The major sources of emissions from the distribution sector are gate stations, metering and pressure regulating equipment, and cast iron and unprotected steel distribution pipe. Emissions depend on the number of customers, consumption, and the rate of cast iron and unprotected steel pipe replacement. The forecast method uses consumption and pipe replacement statistics to estimate future distribution activity factors (EPA/GRI, 1996).

Oil. EPA's current forecast of emissions from oil systems—1.6 MMTCE in 2010, 1.7 MMTCE in 2020—is being revised. The new estimate will reflect that methane emissions from oil systems are directly proportional to the overall size of the petroleum industry. DOE expects U.S. demand for petroleum products to grow by 1.2 percent annually between 1996 and 2020, from 18.4 million barrels per day in 1996 to 24.3 million barrels per day in 2020 (EIA, 1998).

1.4 Emission Estimate Uncertainties

Natural Gas. Uncertainties in the emission estimates stem from the size, complexity, and heterogeneity of the infrastructure of the U.S. natural gas industry. In this analysis, the estimate of methane emissions from natural gas systems is accurate to within plus or minus 25 percent. The estimate of overall accuracy is based on separate assessments of the uncertainties surrounding each activity factor and emission factor used

Exhibit 3-6: Projected Baseline Methane Emissions from Natural Gas Systems (MMTCE)

Source	2000	2005	2010	2015	2020
Production	9.2	9.8	10.6	11.1	10.8
Processing	4.2	4.4	4.6	4.6	4.8
Transmission	13.5	13.7	14.0	14.3	14.6
Distribution	8.8	8.8	8.8	8.7	8.7
Total	**35.6**	**36.7**	**37.9**	**38.7**	**38.8**

Totals may not sum due to independent rounding.

in developing the emission estimate. The total uncertainty range is the sum of the individual uncertainties for each emission source.

Oil. Compared to the natural gas industry, greater uncertainties are associated with all aspects of the methane emission estimates for the oil industry. EPA believes that the current estimation method significantly understates emissions and that methane emissions may be four to five times greater than the estimated 1.6 MMTCE (0.3 Tg) presented here. As noted above, the method for estimating methane emissions from petroleum systems is being updated.

2.0 Emission Reductions

This section describes how EPA estimates the costs and benefits of achieving emission reductions at different potential values for methane. The value of abated methane is the market price of the methane as natural gas, in $/MMBtu, and also may include a carbon equivalent value for emission reductions, if available. The analysis only assesses reductions from natural gas systems and does not include oil systems.

2.1 Technologies for Reducing Methane Emissions

A number of technologies and practices have been identified that can reduce methane emissions from natural gas systems. EPA and the natural gas industry, through the Natural Gas STAR Program, have identified several Best Management Practices (BMPs) that are cost-effective in reducing methane emissions. The Natural Gas STAR Program has sponsored a series of Lessons Learned Studies of these BMPs and several other practices. These studies provide detailed information on the costs of achieving methane emission reductions (EPA, 1997a-h). In addition, companies that are Natural Gas STAR Partners have identified other practices that also reduce methane emissions. The cost analysis described herein is based on the BMPs and Partner-Reported Opportunities (PROs) listed in Exhibit 3-7. More details of these BMPs and PROs are found in Appendix III, Exhibits III-3 and III-4.

2.2 Cost Analysis of Emission Reductions

The objective of the cost analysis is to develop a marginal abatement curve (MAC) from the available options for reducing methane emissions. The MAC is presented as a schedule of emission reductions that could be obtained at increasing values for methane. The analysis considers the value of methane as the sum of its market value as natural gas and a market value for emission reductions represented in dollars per metric ton of carbon equivalent ($/TCE).[1] The MAC is based on a discounted cash flow analysis of the reduction options listed in Exhibit 3-7. The steps in this analysis are described below.

Step 1: Characterize the Reduction Options. Each

Exhibit 3-7: Methane Emission Reduction Options

Natural Gas STAR Best Management Practices

- ✓ Replace or repair high-bleed pneumatic devices with low-bleed devices
- ✓ Practice directed inspection and maintenance at compressor stations
- ✓ Install flash tanks on glycol dehydrators
- ✓ Practice directed inspection and maintenance of gate stations and surface facilities
- ✓ Replace cast iron distribution mains with steel or plastic pipe
- ✓ Replace cast iron distribution services pipe with steel or plastic pipe

Natural Gas STAR Partner-Reported Opportunities

- ✓ Practice directed inspection and maintenance at production sites, processing sites, transmission pipelines, storage wells, and liquid natural gas stations
- ✓ Practice enhanced directed inspection and maintenance, i.e., more frequent survey and repair at production sites, surface facilities, storage wells, offshore platforms, and compressor stations
- ✓ Install electric starters on compressors
- ✓ Install plunger lifts at production wells
- ✓ Use capture vessels for blowdowns at processing plants and other facilities
- ✓ Install instrument air systems
- ✓ Replace/repair chemical injection pumps
- ✓ Use portable evacuation compressors for pipeline repairs
- ✓ Install catalytic converters on compressor engines
- ✓ Conduct electronic metering at gate stations
- ✓ Install fuel gas retrofit systems on compressors to capture otherwise vented fuel when compressors are taken off-line
- ✓ Install static seal systems on reciprocating compressor rods
- ✓ Install dry seal systems on centrifugal compressors
- ✓ Reduce circulation rates on glycol dehydrators

option for reducing methane emissions is defined in the following terms: the emission source to which it applies; capital cost; the number of years that the capital equipment lasts (typically 5 to 15 years depending on the technology); annual operating and maintenance costs; and its efficiency, i.e., achievable emission reduction (up to 100 percent).

The options are matched to emission source definitions in the emission inventory analysis (EPA/GRI, 1996). In addition, in some cases the technologies and practices must be considered in proper order. For example, when identifying potential emission reductions from glycol dehydrators (which remove water during natural gas processing), the option of reducing the glycol recirculation rate must be considered before the higher-cost option of installing flash tanks. EPA assumes that lower-cost options are implemented first, and so the potential emission reductions from flash tanks depend on the remaining volume of emissions after glycol recirculation rates have been reduced. In this way, relationships are defined so that incremental emission reductions are analyzed for each option. In Appendix III, Exhibits III-5 and III-6 list the data used to define the reduction options.

Options can be applied in different segments of the industry and in different settings within each segment. For example, replacing high-bleed pneumatic devices with low-bleed pneumatic devices is applicable in the production, transmission, and distribution sectors. Within each sector, pneumatic devices can be applied at sites with high or low volume throughput.

Step 2: Calculate Break-Even Gas Prices. A discounted cash flow analysis is performed for each emission reduction option to estimate the price of natural gas needed to offset the cost of the option for reducing emissions. The analysis is conducted from the perspective of a private decision-maker in the natural gas industry. Exhibit 3-8 shows the financial assumptions used.

Step 3: Estimate Cost-Effective Emission Reductions for Each Option. The analysis compares the needed break-even price for each methane reduction option against the total value of the abated methane which is the sum of the market value of gas and any emission reduction values. If the value for the abated methane (revenue) is equal to or greater than an option's cost, that option is considered cost-effective. Overall for the gas industry, about one-third of the baseline emissions in 2010 can be cost-effectively reduced at the market value of gas alone, that is, with no additional carbon equivalent values or $0/TCE. More reductions could be achieved with the addition of higher carbon equivalent values. The estimates of achievable reductions are option-specific, which means they are also sector-specific.

Step 4: Generate the Marginal Abatement Curve. The MAC is derived by rank ordering the cost-effective individual opportunities at each combination of gas price and carbon-equivalent emission reduction values. The MAC can also be called a cost or supply curve since it shows the cost per emission reduction amount.

Exhibit 3-8: Financial Assumptions for Emission Reduction Analysis

Parameter	Description
Value of Gas Saved (1996 US$)	Wellhead: $2.17 / MMBtu Pipeline: $2.27 / MMBtu Distribution citygate: $3.27 / MMBtu
Discount Rate	20 percent real
Project Lifetime	5 years
Tax Rate	40 percent
Capital Costs	Vary with equipment
Depreciation Period	Maximum 5 years for large investments; 1 year for small investments
Operating & Maintenance Costs	Expressed as annual costs

2.3 Achievable Emission Reductions and Marginal Abatement Curve

Exhibit 3-9 presents the cumulative emission reductions for selected values of carbon equivalent in 2000, 2010, and 2020. Exhibit 3-10 illustrates how the technologies and practices for reducing methane emissions are applied to the natural gas industry. Given the generic nature of some of the options, e.g., directed inspection and maintenance (DI&M), the options can have different cost and savings when applied to different sectors of the industry, and within sectors to different kinds of equipment.

Exhibit 3-9: Emission Reductions at Selected Values of Carbon Equivalent in 2000, 2010, and 2020 (MMTCE)

	2000	2010	2020
Baseline Emissions	35.6	37.9	38.8
Cumulative Reductions			
at $0/TCE	10.1	10.8	11.0
at $10/TCE	11.6	12.4	12.7
at $20/TCE	11.7	12.5	12.8
at $30/TCE	12.5	13.3	13.6
at $40/TCE	12.5	13.3	13.6
at $50/TCE	14.4	15.3	15.6
at $75/TCE	15.3	16.3	16.7
at $100/TCE	17.4	18.4	18.9
at $125/TCE	18.0	19.2	19.6
at $150/TCE	18.1	19.2	19.7
at $175/TCE	18.1	19.2	19.7
at $200/TCE	18.1	19.3	19.7
Remaining Emissions	17.5	18.6	19.1

The cost effectiveness of an emission reduction option is higher when applied to operations that have greater opportunities to reduce emissions, i.e., components with high throughputs and components that operate continuously versus intermittently. For example, among meter and regulating stations in the distribution sector, DI&M is more cost-effective at larger stations with greater flows of gas than at smaller stations.

The value of natural gas to the system operator also affects the cost-effectiveness of an emission reduction option. Broadly speaking, natural gas is least valuable at the wellhead, i.e., the production sector, and most valuable in the citygate market, i.e., the distribution sector. The cost analysis recognizes this market characteristic by using three sector-specific natural gas prices: $2.17/MMBtu for wellhead, for $2.27/MMBtu for pipeline, and $3.27/MMBtu for citygate.

While a limited number of options are considered, applying these options to various segments of the industry (with corresponding different gas values) and to different equipment types results in the evaluation of 118 opportunities to reduce emissions. Appendix III, Exhibit III-7 provides a full list of these opportunities.

Exhibit 3-11 is derived from Exhibit 3-10 and presents the MAC showing the additional amounts of abated methane per increases in the price of natural gas—the left vertical axis—and additional carbon equivalent values ($/TCE)—the right vertical axis. The horizontal axis is the amount of abated methane.

The energy market price, $2.43/MMBtu in 1996, is aligned to $0/TCE. At $0/TCE, no additional price signals exist from carbon equivalent values to motivate emission reductions; all emission reductions are due to a response to the price of natural gas. As a value is placed on avoided emissions in terms of $/TCE, these values are added to the energy market prices and allow for additional emissions to clear the market. The "below-the-line" amounts, with respect to $/TCE, illustrate this dual price-signal market.

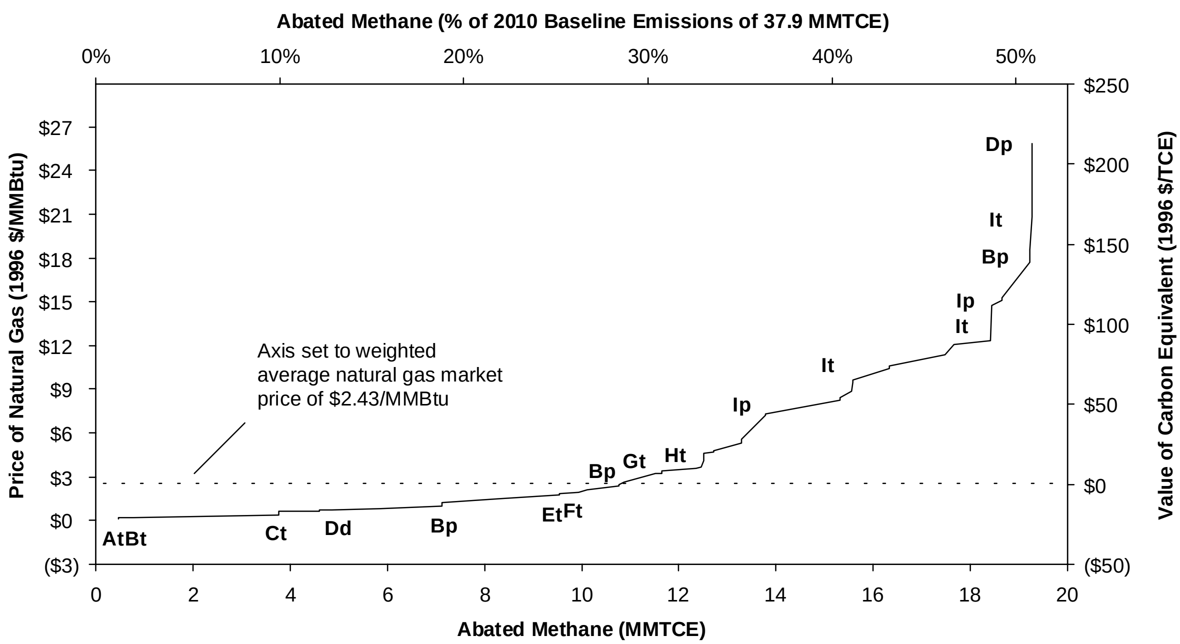
While the detailed analysis uses three different natural gas prices to reflect the increasing value of natural gas as it moves through the system, these three prices were averaged into a single price of $2.43/MMBtu to simplify Exhibit 3-10. Average natural gas prices were also used to calculate carbon equivalent values and cumulative emission reductions in Exhibit 3-10. Sector-specific natural gas prices were used to calculate incremental emission reductions.

The MAC shows that approximately 30 percent of baseline emissions can be cost-effectively reduced at $2.43/MMBtu, the average market natural gas price. At approximately $100/TCE, the MAC becomes inelastic, that is, non-responsive to any increases in the value for abated methane. Further reductions in methane emissions beyond about 50 percent of the baseline are limited given the current set of options evaluated (see below).

Exhibit 3-10: Schedule of Selected Methane Emission Reduction Options in 2010					
	Based on Sector-Specific Natural Gas Prices		Based on Industry Average Natural Gas Price		
Option	Break-Even Gas Price	Incremental Reductions (MMTCE)	Value of Carbon Equivalent ($/TCE)	Cumulative Reductions (MMTCE)	Label on MAC
Install fuel gas retrofit systems on compressors to capture otherwise vented fuel when compressors are taken off-line	$0.12	0.42	($21.06)	0.47	At
Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to high-bleed, continuous-bleed pneumatic devices)	$0.20	0.59	($20.28)	0.78	Bt
Reduce glycol circulation rates in dehydrators (not applicable to Kimray pumps, this option applies to dehydrators with gas assisted pumps but without flash tanks)	$0.45	0.28	($18.03)	3.76	Ct
Practice directed inspection and maintenance at gate stations and surface facilities	$0.75	0.14	($15.26)	4.87	Dd
Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to high bleed, intermittent bleed devices)	$1.00	0.90	($13.01)	7.13	Bp
Install reciprocating compressor rod packing (Static-Pac)	$1.81	0.06	($5.61)	9.54	Et
Install dry seals on centrifugal compressors	$1.91	0.12	($4.73)	9.93	Ft
Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to medium-bleed, intermittent-bleed devices)	$2.50	0.68	$0.63	10.78	Bp
Install flash tank separators	$3.42	0.02	$9.01	11.66	Gt
Conduct electronic monitoring at large surface facilities only	$4.84	0.06	$21.87	12.72	Ht
Replace high-bleed pneumatic devices with compressed air systems [a] (applies to high-bleed, intermittent-bleed devices)	$7.21	0.32	$43.46	13.79	Ip
Replace high-bleed pneumatic devices with compressed air systems [a] (applies to high-bleed turbine devices)	$9.68	0.10	$65.97	15.57	It
Replace high-bleed pneumatic devices with compressed air systems [a] (applies to low-bleed, continuous-bleed devices)	$12.34	0.78	$90.15	18.42	It
Replace high-bleed pneumatic devices with compressed air systems [a] (applies to medium-bleed, intermittent-bleed devices)	$14.77	0.22	$112.20	18.45	Ip
Replace higher-bleed pneumatic devices with lower-bleed pneumatic devices (applies to low-bleed, intermittent-bleed devices)	$18.00	0.01	$141.56	19.22	Bp
Replace high-bleed pneumatic devices with compressed air systems [a] (applies to medium-bleed turbine devices)	$20.81	0.04	$167.11	19.26	It
Practice directed inspection and maintenance at production sites	$25.88	0.02	$213.24	19.29	Dp

[a] This option is coordinated with the option of replacing high-bleed pneumatic devices with low-bleed pneumatic devices.

Exhibit 3-11: Marginal Abatement Curve for Methane Emissions from Natural Gas Systems in 2010



LEGEND

Emission Reduction Options

- **A** = fuel gas retrofit
- **B** = replace higher-bleed pneumatic devices with lower-bleed devices
- **C** = reduce glycol circulation rates in dehydrators
- **D** = directed inspection and maintenance (DI&M)
- **E** = reciprocating compressor rod packing (Static-Pac)
- **F** = dry seals on reciprocating compressors
- **G** = flash tank separators
- **H** = electronic monitoring at large surface facilities
- **I** = replace high-bleed pneumatic devices with compressed air

Natural Gas Industry Sectors

- **p** = applied to the production sector
- **t** = applied to the transmission sector
- **d** = applied to the distribution sector

Note: More than one point can have the same code because the same emission reduction option can be applied to different components of a sector.

2.4 Reduction Estimate Uncertainties and Limitations

The two major areas of uncertainty related to the MAC are: (1) an exclusive focus on currently available technologies; and (2) a lack of data on some of the technologies currently used by industry. By focusing on options that have been reviewed by the Natural Gas STAR Program, the study has not included the possibility that other technologies will be developed in the future that can further reduce methane emissions more efficiently. In addition, data on the PROs is incomplete in many cases. EPA's Natural Gas STAR Program has an ongoing effort to develop more detailed analyses of these opportunities.

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4.0 Explanatory Notes

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[1] Equation to calculate the equivalent gas price for a given value of carbon equivalent:

$$\frac{\$}{TCE} \; x \; \frac{10^6 \, TCE}{MMTCE} \; x \; \frac{5.73 \, MMTCE}{Tg \, CH_4} \; x \; \frac{Tg}{10^{12} \, g} \; x \; \frac{19.2 \; g \; CH_4}{ft^3 \, CH_4} \; x \; \frac{ft^3}{1{,}000 \; Btu} \; x \; \frac{10^6 \; Btu}{MMBtu} = \frac{\$}{MMBtu}$$

Where: 5.73 MMTCE/Tg CH_4 = 21 CO_2/CH_4 x (12 C / 44 CO_2)
Density of CH_4 = 19.2 g/ft^3
Btu content of CH_4 = 1,000 Btu/ft^3

4. Coal Mining

Summary

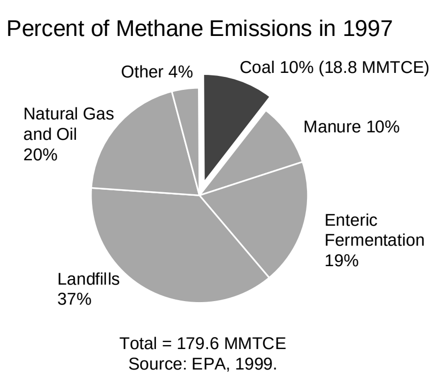
EPA estimates 1997 U.S. methane emissions from coal mines at 18.8 MMTCE (3.3 Tg), accounting for 10 percent of total U.S. anthropogenic methane emissions (see Exhibit 4-1). Methane, formed during coalification, is stored in coal seams and the surrounding strata and released during coal mining. Small amounts of methane are also released during the processing, transport, and storage of coal. Deeper coal seams contain much larger amounts of methane than shallow seams. Accordingly, 65 percent of 1997 U.S. coal mine methane emissions were from underground mines, even though underground mines accounted for only 39 percent of coal production.

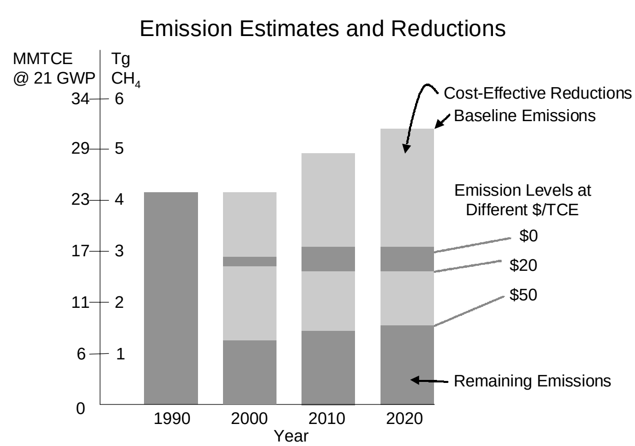
EPA expects methane emissions from U.S. coal mines to increase faster than total U.S. coal production because underground coal production – mined at increasingly greater depths – is projected to grow faster than surface production. EPA estimates that methane emissions from coal mines will reach 28.0 MMTCE (4.9 Tg) by 2010, excluding possible Climate Change Action Plan (CCAP) reductions.

Methane emissions from coal mines can be reduced by methane recovery and use projects at underground mines and by the oxidation of methane in ventilation air using new technologies. In 1997, 14 underground U.S. coal mines recovered and used methane, achieving annual reductions of 4.6 MMTCE (0.8 Tg). Methane recovery technologies include vertical wells drilled from the surface or boreholes drilled from inside the mine. Depending on gas quality, methane recovered from underground mines may be sold to natural gas companies, used to generate electricity, used on-site as fuel for drying coal, or sold to nearby industrial or commercial facilities. The oxidization of coal mine ventilation air produces heat that can be used directly on-site or to produce electricity. Coal mines in the U.S. do not currently use the oxidization technology, but it has been successfully demonstrated in Great Britain.

The Coalbed Methane Outreach Program (CMOP), a voluntary EPA-industry partnership, has identified cost-effective technologies and practices that could reduce projected 2010 U.S. coal mine emissions by 10.3 MMTCE (1.8 Tg). EPA estimates that with a value of $20/TCE for abated methane added to the energy market price, U.S. coal mine methane emissions could be reduced by 13.1 MMTCE (2.3 Tg) in 2010 as shown in Exhibit 4-1 below.

Exhibit 4-1: U.S. Methane Emissions from Coal Mining (MMTCE)





1.0 Methane Emissions from Coal Mining

Methane and coal are formed together during coalification, a process in which plant biomass is converted by biological and geological forces into coal. Methane, stored within coal seams and the surrounding strata, is liberated when pressure above or surrounding a coalbed is reduced as a result of natural erosion, faulting, or underground and surface mining. Small amounts of methane also are liberated during the processing, storage, and transport of coal (referred to as post-mining emissions). Abandoned underground coal mines also contribute to the total amount of methane liberated. This section summarizes the sources of methane emissions from coal mining and details the methodologies EPA uses to estimate current and future methane emissions. The uncertainties associated with these estimates are also presented.

1.1 Emission Characteristics

Emissions vary greatly by type of coal mine and mining operations. This section describes the methane emissions resulting from underground mines, surface mines, post-mining operations, and abandoned mines.

Underground Mines. Deeper coal seams and surrounding strata contain much larger volumes of methane than shallow coal seams. Geologic pressure, which increases with depth, holds more methane in place. Additionally, coal mined underground tends to have a higher rank or carbon content, which correlates to a higher methane content.

As a safety precaution, all underground coal mines with detectable methane emissions must use ventilation systems to ensure that methane concentrations remain below one percent methane in the air of mine workings.[1] Methane is explosive at concentrations of five percent or greater; thus for safety reasons mine workings are operated at methane levels well below the five percent threshold. Ventilation systems consist of large fans that draw vast quantities of air into mine workings to lower methane concentrations. The ventilation air (extracted mine air containing low concentrations of methane) is then vented to the atmosphere through ventilation shafts or bleeders.

Degasification systems, which are vertical wells drilled from the surface or boreholes drilled within the mine, remove methane contained in the coal or surrounding strata before or after mining so that it does not enter the mine. In contrast to ventilation systems, degasification systems recover methane in high concentrations ranging from 30 to over 90 percent, depending on the degasification technique and coal geology.

Surface Mines. Surface mining is used to mine coal located at shallow depths. Because the coalbed at surface mines has little overburden, little pressure exists to keep methane in the coal. Hence, coal at surface mines tends to have a low methane content. As overburden is removed and the coal seam is exposed during surface mining, methane is emitted directly to the atmosphere. Although surface mines accounted for over 61 percent of U.S. coal production in 1997, they accounted for only an estimated 14 percent of methane emissions.

Post-Mining Operations. Although a significant amount of methane is released from the coal seam during mining activities, some methane remains in the coal after it is removed from the mine. This methane may be emitted from the coal during processing, storage, and transportation. The rate at which methane is emitted during post-mining activities depends on the characteristics of the coal and the way it is handled. For instance, the highest releases occur when coal is crushed, sized, and dried for industrial and utility uses. Post-mining emissions can continue for months after mining.

Abandoned Mines. Abandoned underground coal mines are also a source of emissions. A few gas developers are recovering and using methane from abandoned mines. EPA is conducting further research into this emission source. The current emission estimates do not include emissions from abandoned mines.

The majority of methane emissions from coal mining are from a few very large and gassy, i.e., high-emitting, underground mines. The most gassy 125 (of 573) underground coal mines account for over 97 percent of underground methane liberated and about 65 percent of methane liberated from all coal mines. Future trends at these gassy mines, including the potential for methane recovery and use, will have a large impact on future emission levels.

1.2 Emission Estimation Method

Total methane emissions from coal mining are estimated by summing methane emissions from underground mines, surface mines, and post-mining activities.

1.2.1 Underground Mines

Methane liberated from coal mines includes emissions from ventilation and degasification systems. Some coal mines recover and use the methane collected from degasification systems. Accordingly, this portion is subtracted from total methane liberated to determine methane emitted from underground mines.

Ventilation Systems. As mentioned previously, all underground coal mines with detectable methane emissions must use ventilation systems to ensure that methane concentrations remain within safe levels. Ventilation air typically contains methane concentrations below one percent. The Mine Safety and Health Administration (MSHA) measures methane emissions from ventilation systems on a quarterly basis. Based on these measurements, MSHA estimates average daily methane emissions for each underground mine (MSHA, 1998). For 1997, MSHA compiled the average daily methane emissions for all mines with detectable methane emissions into a single database, which provides the basis for EPA's method of estimating methane emissions from ventilation systems. First, EPA estimates annual methane emissions for each mine by multiplying the daily average by 365 days per year. Next, total annual methane emissions from ventilation systems were estimated by summing annual ventilation emissions from individual mines.

The 1997 MSHA database includes methane emission data for over 500 of the estimated 950 underground mines in the United States. Those mines not listed in the MSHA database do not have detectable levels of methane and the emissions from this group of mines are assumed to be negligible.

The methodology for estimating ventilation emissions for the years prior to 1997 is slightly different than the approach used for 1997 (see Exhibit 4-2). The 1997 MSHA database contains data for all mines with detectable methane emissions, and, consequently, reports on 100 percent of all ventilation emissions (MSHA, 1998). The MSHA data indicates that 97.8 percent of ventilation emissions come from mines emitting at least 0.1 million cubic feet per day (MMcf/d) and 94.1 percent of total emissions come from mines emitting at least 0.5 MMcf/day. EPA uses these estimates to prorate other data that are only representative of the mines emitting methane above these levels. For example, the estimates for 1990, 1993, and 1994 are based on a U.S. Bureau of Mines database that reported mine-specific information for all mines emitting at least 0.1 MMcf/d from their ventilation systems (DOI, 1995). Similarly,

Exhibit 4-2: Approach Used to Estimate Ventilation Emissions

Year	Data/Method Used
1990	U.S. Bureau of Mines database listing all mines with ventilation emissions greater than 0.1 MMcf/d. EPA adjusted total emissions to account for mines not included in the database. Assumed to account for 97.8% of total emissions.
1991	Total underground coal mining emissions are estimated by using emission factors developed in 1990 and multiplying those factors by 1991 coal production. Annual ventilation data are unavailable.
1992	Same approach as 1991, using 1992 coal production data.
1993	Same approach as 1990, using 1993 data. Assumed to account for 97.8% of total emissions.
1994	Same approach as 1990, using 1994 data. Assumed to account for 97.8% of total emissions.
1995	Obtained data from MSHA for all mines emitting at least 0.5 MMcf/d. Total was then adjusted to account for mines for which data were not collected. Assumed to account for 94.1% of total emissions.
1996	Same approach as 1995, using 1996 data. Assumed to account for 94.1% of total emissions.
1997	MSHA database containing ventilation emissions for all underground coal mines with detectable emissions. Assumed to account for 100% of total.

the 1995 and 1996 data are based on MSHA mine-specific ventilation emissions for all mines emitting at least 0.5 MMcf/d. Due to a lack of mine-specific emissions for 1991 and 1992, EPA estimates total underground emissions by multiplying emission factors, based on 1990 data, by coal production in the relevant year.

Degasification Systems. In 1997, 24 U.S. coal mines used degasification systems as a supplement to their ventilation systems. In the U.S., the three most common types of degasification methods are vertical wells and horizontal boreholes, drilled in advance of mining, and gob wells, drilled post mining. MSHA reports the coal mines that are employing degasification systems and the type of degasification systems used. However, MSHA does not measure or report the amount of methane liberated from degasification systems. Some U.S. coal mines provide EPA with information about their emissions from degasification systems. In other cases, EPA estimates the amount of methane liberated based on the type of degasification system employed and mine characteristics. Exhibit 4-3 shows U.S. coal mines employing degasification systems, the type of system employed, and the estimated amount of methane liberated and used.

Methane Used. Coal mines first began large scale use of methane recovered from degasification systems in the late 1970s. Since that time, methane recovery and use has increased substantially. In 1997, 14 active U.S. coal mines recovered and used or sold some or all of the methane recovered by their degasification systems. For each of these mines, the quantity of methane recovered is indicated in Exhibit 4-3. All of these active mines sell methane to natural gas companies, since methane is the principal component of natural gas. In addition, one of the mines uses a portion of the meth-

Exhibit 4-3: Mines Employing Degasification Systems and Methane Use Projects in 1997

Mine Name	Type of Degasification System Used	Methane Liberated from Degas System (MMcf/year)	Methane Used (MMcf/year)
Buchanan No. 1	Vertical, Horizontal, Gob	10,706	10,050
VP No. 8	Vertical, Horizontal, Gob	7,951	7,687
VP No. 3	Vertical, Horizontal, Gob	7,160	6,922
Blue Creek No. 7	Vertical, Horizontal, Gob	4,883	4,883
Blue Creek No. 4	Vertical, Horizontal, Gob	3,603	3,603
Blue Creek No. 3	Vertical, Horizontal, Gob	3,057	3,057
Blue Creek No. 5	Vertical, Horizontal, Gob	2,573	2,573
Pinnacle No. 50	Vertical, Horizontal, Gob	2,356	522
Enlow Fork	Gob	2,356	-
Cumberland	Vertical, Horizontal, Gob	2,341	-
Blacksville No. 2	Horizontal, Gob	2,074	149
Bailey	Gob	1,681	-
Oak Grove	Vertical, Horizontal, Gob	1,657	1,408
Emerald No. 1	Horizontal, Gob	1,351	-
Federal No. 2	Vertical, Horizontal, Gob	1,105	197
Loveridge No. 22	Horizontal, Gob	988	74
Dilworth	Gob	827	-
Robinson Run No. 95	Horizontal, Gob	750	-
Shoal Creek	Vertical, Horizontal, Gob	489	440
McElroy	Gob	299	-
Shoemaker	Gob	261	-
Maple Meadow	Gob	170	-
Baker	Gob	83	-
Humphrey No. 7	Horizontal, Gob	19	2

Note: Although all of the mines listed above liberated methane in 1997, not all of them sold (used) the methane recovered.

Source: MSHA, 1998; Mine Owners and Operators; State Petroleum and Natural Gas Agencies' Gas Sales Data; EPA, 1997a.

ane recovered from gob wells as fuel for an on-site gas-fired coal dryer.

EPA estimates methane emissions avoided over time for each U.S. recovery and use project. All of the projects must report methane sales to state agencies responsible for monitoring sales of natural gas. EPA uses gas sales information reported by state agencies, as well as information supplied by the coal mines, to estimate the emission reductions for a particular year. For coal mines that recover methane while mining, the emission reductions are estimated as the reported gas sales amount, adjusted for additional methane use in gas-fired compressors.

For projects that recover methane in advance of mining, estimating emission reductions is more complex. For these projects, the emission reductions are counted during the year in which the methane would otherwise have been emitted, i.e., the year during which the well is mined-through. The estimates are calculated based on reported gas sales over time, the portion of gas sales coming from pre-mining degasification systems, and the number of years in advance of mining that methane is recovered. In some cases, the amount of gas sold or used does not equal the amount liberated from degasification systems since part of the gas (up to 20 percent) is simply vented (see Buchanan No. 1 in Exhibit 4-3 for one example). Currently, U.S. coal mines only use methane that has been recovered from degasification systems; however, in the future, U.S. coal mines could potentially use methane from ventilation systems (EPA, 1999b).[2]

1.2.2 Surface Mines

With the exception of a few field studies, methane emissions from surface mines have not been measured or estimated on a mine-specific basis. Methane emissions from surface mines are estimated by multiplying surface coal production for each coal basin by a basin-specific emission factor. This factor is calculated by multiplying the average methane in-situ content of surface-mined coals by a factor of two to account for methane contained in overlying or underlying coal seams or other strata (EPA, 1993).

1.2.3 Post-Mining

Post-mining emissions are estimated by multiplying basin-specific coal production for surface and underground mines by a factor equal to 33 percent of the average basin-specific in-situ content of the coal. Different average methane in-situ values are used for surface mines and for underground mines (EPA, 1993).

1.2.4 Methodology for Estimating Future Methane Liberated

To estimate the amount of methane that will be liberated from coal production in the future, emission factors are multiplied by estimates of future coal production. Emission factors have been developed for underground mines, surface mines, and post-mining activities using 1997 data. These emission factors are then multiplied by projected surface and underground coal production levels to estimate future emissions. The opening and closing of very gassy mines is also taken into account since these changes significantly impact overall emissions.[3]

1.3 Emission Estimates

This section presents estimated methane emissions from coal mining from 1990 through 1997 and projected methane emissions through 2020.

1.3.1 Current Emissions and Trends

EPA estimates that the U.S. coal mining industry emitted 18.8 MMTCE (3.3 Tg) of methane in 1997. Mining in deep coal seams accounted for 65 percent of methane emitted from coal mining in 1997, totaling 12.3 MMTCE (2.1 Tg). As shown in Exhibit 4-4, methane emissions from coal mining declined from 1990 to 1997. This decline is due to three main factors. First, several gassy mines closed. These closures are due in part to reduced demand for high-sulfur coal in response to the Clean Air Act, which places strict requirements on utilities to reduce their sulfur dioxide emissions. Other mines closed due to declining coal prices, while others simply reached the end of their productive lifetime. Second, methane recovery and use has increased significantly at underground mines; EPA estimates that the amount of emissions avoided increased from 1.6 MMTCE (0.3 Tg) in 1990 to 4.6

Exhibit 4-4: Methane Emissions from Coal Mining (MMTCE)								
Activity	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**
Underground Liberated	18.8	18.1	17.8	16.0	16.3	17.7	16.5	16.8
Underground Used	(1.6)	(1.7)	(2.1)	(2.7)	(3.2)	(3.4)	(3.8)	(4.6)
Net Underground Emissions	17.1	16.4	15.6	13.3	13.1	14.2	12.6	12.3
Surface Emissions	2.8	2.6	2.6	2.5	2.6	2.4	2.5	2.6
Post-Mining Emissions (Underground)	3.6	3.4	3.3	3.0	3.3	3.3	3.4	3.5
Post-Mining Emissions (Surface)	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	**24.0**	**22.8**	**22.0**	**19.2**	**19.4**	**20.3**	**18.9**	**18.8**

Totals may not sum due to independent rounding.
Source: EPA, 1999a.

MMTCE (0.8 Tg) in 1997. Third, although total coal production has increased, the percentage of total production from underground mines has declined slightly. Since underground production drives the total quantity of methane liberated from coal mines, a decline in underground production leads to a decline in methane liberated. Appendix IV, Exhibit IV-1 provides historical and projected coal production data.

1.3.2 Future Emissions and Trends

Although the amount of methane liberated from coal mining decreased over the past ten years, it is projected to increase between 2000 and 2020, as Exhibit 4-5 indicates. This projection is based on forecasted levels of coal production for both underground and surface mines developed by the Energy Information Administration of the U.S. Department of Energy (EIA, 1998b). Estimates for 2000 may overstate underground liberated emissions because of the closure of some very gassy mines in 1998 and 1999 that have not yet been taken into account.

1.4 Emission Estimate Uncertainties

The level of uncertainty associated with the emission estimates varies for each of the emission sub-sources.

Underground Ventilation Systems. As described above, methane emissions from ventilation systems are based on quarterly measurements taken by MSHA at individual mines. To the extent that the average of the four quarterly measurements are not representative of the true average at a given mine, average emissions at a particular mine may be over- or under-estimated. In addition, there are some limited uncertainties associated with the potential for measurement and reporting errors.

Underground Degasification Systems. MSHA reports which mines employ degasification systems and the type of degasification system used, but the agency does not record the quantity of methane liberated from degasification systems. Although coal mines are not required to publish methane liberation data, some have provided it to EPA. For other mines, EPA has estimated methane liberated based on the type of degasification system employed. The uncertainty is higher for those mines where EPA has estimated the amount of methane liberated. However, EPA has more data from gassy mines than from less gassy mines, thereby reducing overall uncertainty.

Exhibit 4-5: Projected Baseline Methane Emissions from Coal Mining (MMTCE)					
Activity	**2000**	**2005**	**2010**	**2015**	**2020**
Underground Liberated	17.1	19.3	20.4	21.5	22.1
Surface Liberated	2.8	2.8	2.9	3.0	3.2
Post-Mining Liberated (Underground)	3.5	4.0	4.2	4.5	4.6
Post-Mining Liberated (Surface)	0.5	0.5	0.5	0.5	0.5
Total	**23.9**	**26.6**	**28.0**	**29.5**	**30.4**

Totals may not sum due to independent rounding.

Methane Used at Underground Mines. As mentioned previously, all coal mines must report gas sales to state agencies responsible for monitoring gas production. While little uncertainty exists associated with the reported gas sales, uncertainty exists associated with the timing of the emission reductions. For coal mines that recover methane in advance of mining, the emission reduction is accounted for in the year in which the coal seam is mined-through. Thus, without knowing the exact timing of operations, there is uncertainty associated with estimating the timing of methane emissions avoided.

Surface Mines. Previous studies have indicated that methane emissions from surface mines are likely to be from one to three times greater than the in-situ content of the coal. EPA's emission estimation methodology assumes a value of two times the in-situ content of the coal. Additional uncertainty is related to the estimated average in-situ content for each basin.

Post-Mining Emissions. The uncertainties related to post-mining emissions are similar to those for surface mining emissions since a similar methodology is used.

Uncertainties Associated with Future Emissions. Future emissions are estimated for different sub-sources by multiplying the average emissions per ton of coal by projected future coal production levels. Accordingly, two additional sources of uncertainty are associated with the emission projections. First, the average emissions per ton of coal may change over time. Second, actual coal production levels may vary from projected coal production levels.

2.0 Emission Reductions

This section surveys the technologies and practices available for reducing coalbed methane emissions, analyzes the cost of implementing three "model" projects that integrate these abatement options, and highlights which options are most achievable and cost-effective through the development of a marginal abatement curve (MAC).

2.1 Technologies for Reducing Methane Emissions

Methane emissions from coal mines can be reduced through the implementation of the methane recovery and use projects described below.

2.1.1 Methane Recovery

Coal mines already employ a range of technologies for recovering methane. These methods have been developed primarily for safety reasons, as a supplement to ventilation systems. The major degasification techniques used at U.S. coal mines are vertical wells, longhole and shorthole horizontal boreholes, and gob wells. Exhibit 4-6 summarizes these technologies. Vertical wells and in-mine horizontal boreholes, which recover methane in advance of mining, produce nearly pure methane. In contrast, gob wells, which recover post-mining methane, may recover methane that has been mixed with mine air. The quality of the gas determines how it may be used.

Even where degasification systems are used, mines still emit significant quantities of methane via ventilation systems. Currently, technologies are in development that catalytically oxidize the low concentrations of methane in ventilation air producing usable thermal heat as a by-product.

2.1.2 Methane Use

Methane recovered from degasification can be used for the purposes described below.

Pipeline Injection. Natural gas companies may purchase methane recovered from coal mines. Most pipeline companies require gas with a methane concentration of at least 97 percent. Since gas recovered in advance of mining is nearly pure methane, the only processing required may be dehydration.

Gob gas, however, typically does not have a methane concentration greater than 97 percent. U.S. coal mines have developed different approaches for selling gob gas to natural gas companies. Two major projects, involving several coal mines in Alabama and Virginia, recover methane from gob wells for sale to a natural gas company. These coal mines have developed

Exhibit 4-6: Summary of Degasification Techniques

Method	Description	Methane Quality	Recovery Efficiency[a]	Current Use in U.S. Coal Mines
Vertical Wells	Drilled from the surface to coal seam several years in advance of mining.	Recovers nearly pure methane.	Up to 60%	Used by at least 3 U.S. mining companies in about 11 mines.
Gob Wells	Drilled from the surface to a few feet above coal seam just prior to mining.	Recovers methane that is sometimes contaminated with mine air.	Up to 50%	Used by more than 21 U.S. mines.
Shorthole Horizontal Boreholes	Drilled from inside the mine to degasify the coal seam just prior to mining.	Recovers nearly pure methane.	Up to 20%	Used by approximately 16 U.S. mines.
Longhole Horizontal Boreholes	Drilled from inside the mine to degasify the coal seam up to several years before mining.	Recovers nearly pure methane.	Up to 50%	Used by over 10 U.S. mines.
Cross-Measure Boreholes	Drilled from inside the mine to degasify surrounding rock strata.	Recovers methane that is sometimes contaminated with mine air.	Up to 60%	Not widely used in the U.S.

[a] Percent of total methane liberated that is recovered by degasification systems.

Source: EPA 1993, 1997b, and 1999a; Expert comments.

strategies for controlling the amount of air entering the gob and annually monitor gas quality in the well. These methods are highly effective, especially during the early stages of the productive lifetime of an individual gob well.

Power Generation. Coal mine methane is also used to generate electricity. In contrast to pipeline injection, power generation does not require nearly pure methane. Accordingly, methane recovered from gob wells may be used directly as fuel for a power generation project. At present, only one active U.S. mine uses recovered methane for power generation. In addition, an abandoned coal mine in Ohio also recovers methane to generate electricity for a neighboring, active coal mine.[4]

The methane contained in ventilation air may be used as combustion air in a turbine or internal combustion (IC) engine. Currently, BHP has developed a power generation project at the Appin and Tower coal mines in Australia. The project involves using methane recovered from degasification systems as the main fuel for 94 internal combustion engines rated at one MW each. The project uses about 1.3 million cubic feet a day of methane from ventilation air for this purpose (EPA, 1998). The thermal energy recovered from the oxidation of mine ventilation air can also be used in a steam turbine to generate power (CANMET, 1998; EPA, 1999b).

On-Site Use in a Thermal Coal Drying Facility. As with power generation, a thermal dryer does not require pure methane. Currently, one coal mine in Virginia uses methane recovered from gob wells as fuel for its thermal coal dryer. The thermal energy recovered from the oxidation of mine ventilation air may also be used for on-site drying operations.

Sale to Nearby Commercial or Industrial Facilities. Another option is for coal mines to sell recovered methane to nearby commercial or industrial facilities with a high demand for natural gas. In the early 1990s, gas recovered from coal mines in northern West Virginia was sold to a glass factory.

2.2 Cost Analysis of Emission Reductions

EPA estimates potential emission reductions by evaluating the ability of coal mines to cost-effectively build and operate systems for recovering and using, or oxidizing coal mine methane. EPA developed a MAC by evaluating a range of energy prices along with a range of emission reduction values. To determine cost-effectiveness, EPA assumes that in addition to the value of the energy produced, the mine owner/operator receives income equal to the emission reduction value, in $/ton of carbon equivalent ($/TCE), multiplied by the amount of methane abated. The cost-effectiveness of various options is estimated by comparing the value of the energy and the emission reduction to the costs of the system. The analysis is described below.

Step 1: Define the Current Underground Mines. The analysis is performed on underground mines that released at least 0.5 MMcf/d of methane from ventilation systems in 1997. These 58 mines account for about 94 percent of the methane released from U.S. underground coal mining (MSHA, 1998). EPA characterizes these mines in terms of coal basin, annual coal production, methane released from the ventilation system, existence of degasification system, methane recovered by the degasification system (if one is present), and mining method, i.e., longwall or room and pillar (EPA, 1999a). Where applicable, EPA estimates the amount of methane recovered from existing degasification systems. Using these data, EPA calculates the amount of methane liberated per ton of coal mined. EPA uses this liberation rate to estimate the amount of gas available for recovery per ton of coal mined.

Step 2: Future Coal Production and Future Mines. The Energy Information Administration estimates that coal production will increase 16 percent by 2010 and 26 percent by 2020 relative to 1997 production (EIA, 1998a). See Appendix IV, Exhibit IV-1 for details. Several characteristics of existing mines are assumed to be the same for future mines, such as the methane liberation rate per ton of coal. Therefore, the data set of current mines is used to represent future mines, with the exception that coal production at each mine is scaled over time to correspond with projected changes in underground U.S. coal production.

Step 3: Define "Model" Projects. The three types of modeled recovery and use options analyzed are described below and are also outlined in Exhibit 4-7.

- **Option 1: Degasification and Pipeline Injection.** Under this option, coal mines recover methane using vertical wells drilled five years in advance of mining, horizontal boreholes drilled one year in advance of mining, and gob wells. All of the gas recovered is sold to a pipeline. However, only the high-quality gas produced during the early stages of production from gob wells is assumed to be sold due to the declining gas quality over time. Methane recovery and use under this option varies by basin. EPA assumes that the technology to recover methane will improve over time, leading to increased methane recovery. (See Appendix IV, Exhibit IV-3 for a table of baseline coal basin recovery efficiencies by year.)
- **Option 2: Enhanced Degasification, Gas Enrichment, and Pipeline Injection.** This option consists of gas recovery-and-use incremental to Option 1. As in Option 1, EPA assumes that coal mines recover methane using vertical wells drilled five years in advance of mining, horizontal boreholes drilled one year in advance of mining, and gob wells drilled just prior to mining and that gas is sold to a pipeline. However, well spacing is tightened to increase recovery efficiency. Additionally, mines invest in enrichment technologies to enhance gob gas for sale to natural gas companies. This combination of tightened well spacing and gas enrichment increases recovery efficiency by 20 percent above what could have been achieved in Option 1. Accordingly, Option 2 results in an additional 20 percent of gas that is available for pipeline sale.

Exhibit 4-7: Summary of Options Included in the U.S. Coal Mine Cost Analysis of Methane Emission Reductions

Option	Technologies	Assumptions
1	Degasification and Pipeline Injection	All gas recovered from vertical wells and in-mine boreholes is sold to a pipeline. Only high quality gob gas is sold to the pipeline.
2	Enhanced Degasification, Gas Enrichment, and Pipeline Injection	Incremental to Option 1 with tightened well spacing and gas enrichment. Recovery and use efficiency increases 20% over Option 1.
3	Catalytic Oxidation	Ventilation air is oxidized.

- **Option 3: Catalytic Oxidation.** Under this option, coal mines eliminate methane in their ventilation air using a catalytic oxidizer system with a maximum capacity of 211,860 standard cubic feet per minute (scf/min). The catalytic oxidizer is estimated to oxidize up to 98 percent of the methane that passes through the system. This option can be implemented alone or in conjunction with either of the other two options. Although the heat produced by the system could potentially be used to produce electricity, EPA did not model this option due to the current lack of operational data.

As shown in Appendix IV, Exhibit IV-4, the number of wells required for any option is a function of the amount of coal mined. The size and cost of other equipment is driven by the amount of gas produced, which depends on the amount of coal mined, the rate of methane liberated per ton of coal produced, and the recovery efficiency. For those mines that already have degasification systems in place, these costs were considered sunk costs and were not included. Costs for royalty payments are also not included.

Step 4: Calculate Break-Even Emission Reduction Values. EPA performs a discounted cash flow analysis to calculate the break-even emission reduction values for Options 1, 2, and 3 for each of the 58 mines in 2000, 2010, and 2020. Exhibit 4-8 shows the financial assumptions. Costs are estimated for each mine using these assumptions and the data defined in Step 3. Project costs include only the incremental costs of methane recovery and use. For example, to the extent that a coal mine would already employ degasification systems as part of normal mining practices, the cost of drilling degasification wells or boreholes would not be an incremental cost of a methane use project. EPA estimates the revenue associated with the project as the gas price times the amount of gas recovered and sold.

Step 5: Estimate Emission Reductions for Each Option. The final step is to estimate cost-effective national emission reductions for 2000, 2010, and 2020 within a range of gas prices and emission reduction values in $/TCE. The base gas price is $2.53/MMBtu, which is the average 1996 wellhead gas price in Alabama, Indiana, Kentucky, and Ohio (EIA, 1997).[5] The additional emission reduction values, expressed in $/TCE, range from $0/TCE to $200/TCE. The emission reduction values are translated into gas prices using a global warming potential (GWP) for methane of 21 and a methane energy content of 1,000 Btu/cubic foot.[6] If the break-even gas price for the mine is equal to or less than the sum of the estimated gas price plus the emission reduction value, the emissions can be reduced cost-effectively. For Options 1 and 2, EPA estimates total emission reductions to be the sum of the emissions that can be recovered cost-effectively at the 58 mines for each combination of gas price and emission reduction value. For Option 3, the break-even emission reduction value is used to define the cases in which this option is cost-effective. The emission reduction is applied to all underground mining ventilation emissions that are calculated to be cost-effective.

2.3 Achievable Emission Reductions and Marginal Abatement Curve

This analysis indicates that projected 2010 methane emissions from U.S. coal mining can be reduced by approximately 10.3 MMTCE (1.8 Tg) or 37 percent below baseline projections by implementing currently available technologies that are cost-effective at energy market prices alone. Additional reduction options are cost-effective at carbon equivalent values greater than

Exhibit 4-8: Financial Assumptions for Emission Reduction Analysis

	Description	
Parameters	**Options 1 and 2**	**Option 3**
Base Gas Price (1996 US$)	$2.53/MMBtu	Not applicable
Discount Rate	15 percent real	15 percent real
Project Lifetime	15 years	10 years
Tax Rate	40 percent	40 percent
Depreciation Period	15 years	5 years

$0/TCE. At $20/TCE, baseline emissions in 2010 from U.S. coal mines could be reduced by 13.1 MMTCE (2.3 Tg) or 47 percent.

Exhibit 4-9 presents the cumulative emission reductions at selected values of carbon equivalent in 2000, 2010, and 2020. Exhibit 4-10 provides a schedule of selected emission reduction options for U.S. coal mines for 2010. Option 1 has a lower break-even price (lower cost) than Option 2 for any given mine. For example, the break-even price for Option 1 at Buchanan No. 1 is $0.54/MMBtu compared to $1.63/MMBtu for Option 2. The same methane reduction option becomes cost-effective at different break-even gas prices for different mines depending on the incremental amount of methane that can be recovered and used and the costs of methane recovery.

Exhibit 4-9: Emission Reductions at Selected Values of Carbon Equivalent in 2000, 2010, and 2020 (MMTCE)

	2000	2010	2020
Baseline Emissions	23.9	28.0	30.4
Cumulative Reductions			
at $0/TCE	7.1	10.3	12.5
at $10/TCE	8.0	12.0	13.9
at $20/TCE	8.2	13.1	15.3
at $30/TCE	16.8	20.0	21.7
at $40/TCE	16.8	20.0	21.7
at $50/TCE	16.8	20.0	21.7
at $75/TCE	16.8	20.0	21.7
at $100/TCE	16.8	20.0	21.7
at $125/TCE	16.8	20.0	21.7
at $150/TCE	16.8	20.0	21.7
at $175/TCE	16.8	20.0	21.7
at $200/TCE	16.8	20.0	21.7
Remaining Emissions	7.1	8.0	8.7

Exhibit 4-11 presents the MAC which is derived by a rank order of cost-effective individual opportunities at each combination of gas price and carbon equivalent emission reduction value, i.e., the cost per emission reduction amount. The options shown in Exhibit 4-10 are labeled along the MAC at increasing break-even prices through to $29.70/TCE.

At $29.70/TCE the catalytic oxidizer technology becomes cost-effective.[7] The MAC becomes inelastic because all methane emissions from ventilation air can be reduced cost-effectively.[8] The maximum amount of emission reductions that can be achieved in 2010 assuming that the catalytic oxidizer is used is 20.0 MMTCE (3.5 Tg), or 71 percent of all methane liberated from coal mines in the U.S., which is equivalent to nearly all methane liberated from underground mines in the U.S.

2.4 Reduction Estimate Uncertainties and Limitations

Overall, this analysis is limited by the lack of detailed site-specific assessments. Coal mine methane recovery and use is greatly affected by site-specific conditions. In general, average industry costs are used along with conservative assumptions, so as not to overestimate emission reductions that could be achieved.

The cost analysis only considers recovering methane in advance of mining and selling the gas to natural gas companies or oxidizing the methane in ventilation air. For some smaller, less gassy mines, more limited recovery and use options may be cost-effective. Consequently, the analysis is conservative in that additional emission reduction opportunities may exist.

The analysis does not account for the incremental benefits that will accrue from the installation of degasification systems, such as decreased ventilation costs or increased productivity. Thus, the analysis is conservative to the extent that mines realize significant financial benefits to their mining operations from the installation of degasification projects.

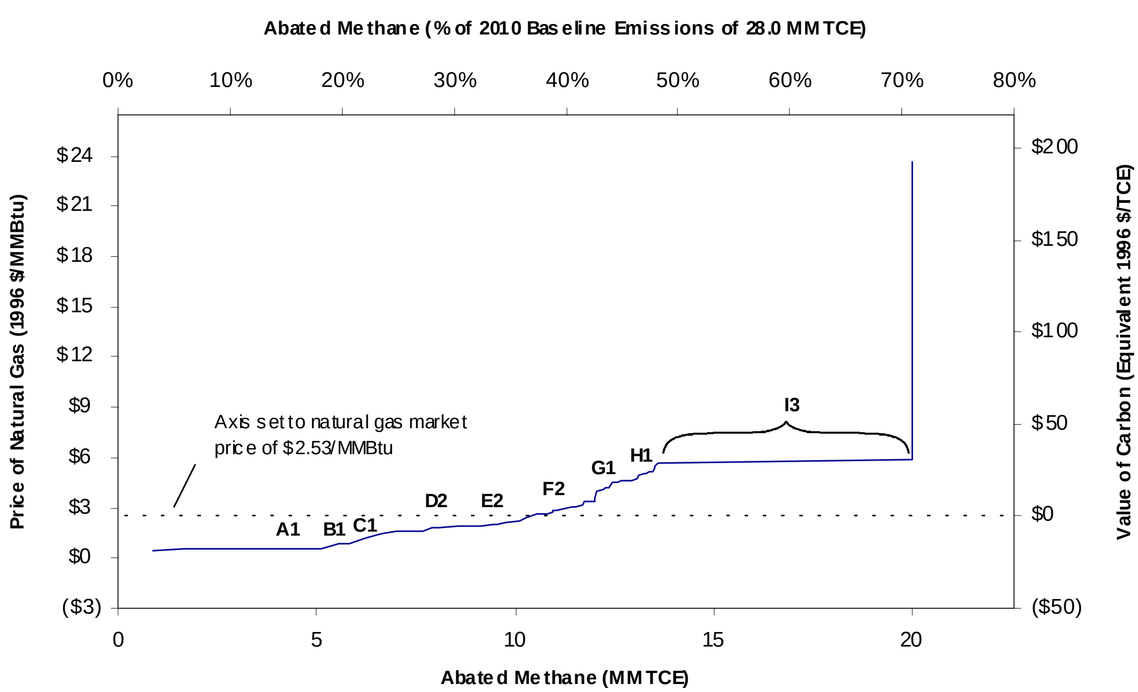
Finally, uncertainty exists regarding the capital and operation and maintenance (O&M) costs for the technologies. In particular, the catalytic oxidation technology at coal mines is under development and limited data are available to estimate costs. Consequently, EPA bases the unit costs on an existing demonstration project and assumes that the costs for catalytic oxidation are proportional to the methane ventilated from underground mines. Given that the cost is based on only one project, EPA cannot assess the extent to which the costs are being over- or under-estimated.

Option Used[a]	Representative Mine[b]	Coal Production (Million Short Tons/yr)	Break-Even Gas Price ($/MMBtu)	Value of Carbon Equivalent ($/TCE)	Emission Reductions (MMTCE)	Incremental Reductions (MMTCE)	Cumulative Reductions (MMTCE)	Label on MAC
	Sample Coal Mines					National		
1	Buchanan No. 1	5.26	$0.54	$(18.05)	1.22	4.05	4.05	A1
1	Blue Creek No. 3	2.78	$0.60	$(17.51)	0.48	1.05	5.10	B1
1	Oak Grove	3.17	$0.85	$(15.23)	0.25	0.72	5.82	C1
2	Buchanan No. 1	5.26	$1.63	$(8.14)	0.41	1.61	7.42	D2
2	Blue Creek No. 3	2.78	$1.94	$(5.32)	0.19	1.69	9.12	E2
2	Sanborn Creek	1.94	$3.33	$7.32	0.07	2.63	11.74	F2
1	McElroy	6.48	$4.59	$18.78	0.16	1.08	12.83	G1
1	Maple Creek	2.27	$5.63	$28.24	0.05	0.75	13.58	H1
3	*All Underground Mines*	NA[c]	$5.79	$29.70	20.00	6.42	20.00	I3

Exhibit 4-10: Schedule of Emission Reduction Options in 2010

[a] Option 1 = Degasification and Pipeline Injection; Option 2 = Enhanced Degasification, Gas Enrichment, and Pipeline Injection; Option 3 = Catalytic Oxidation of Ventilation Air Emissions.
[b] This representative sample of coal mines existed in 1997. Although EPA uses data from these mines to model future emission reductions, EPA does not evaluate whether any specific mine would be operating in 2010.
[c] Not Applicable.

Exhibit 4-11: Marginal Abatement Curve for Methane Emissions from Coal Mining in 2010



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4.0 Explanatory Notes

[1] The Mine Safety and Health Administration (MSHA) records coal mine methane readings with concentrations greater than 50 ppm (parts per million) methane. Readings below this threshold are considered non-detectable.

[2] One coal mine in Australia has recovered and used ventilation air as a fuel for a series of internal combustion engine-driven generators. In addition, a British coal mine reported successful demonstration of oxidation technology.

[3] In 1998 and 1999, the VP No. 3, VP No. 8, and Blue Creek No. 3 mines closed. These closures will significantly reduce total U.S. methane emissions.

[4] Additionally, coal mines in Australia, China, Germany, and the United Kingdom have successfully developed power generation projects at active underground mines.

[5] Gas prices in key coal mine states, e.g., West Virginia, Virginia, Pennsylvania, and Illinois, are assumed to fall within the range of prices represented by the states with available data.

[6] Equation to calculate the equivalent gas price for a given value of carbon equivalent:

$$\frac{\$}{TCE} \, x \, \frac{10^6 \, TCE}{MMTCE} \, x \, \frac{5.73 \, MMTCE}{Tg \, CH_4} \, x \, \frac{Tg}{10^{12} \, g} \, x \, \frac{19.2 \, g \, CH_4}{ft^3 \, CH_4} \, x \, \frac{ft^3}{1{,}000 \, Btu} \, x \, \frac{10^6 \, Btu}{MMBtu} = \frac{\$}{MMBtu}$$

Where: 5.73 MMTCE/Tg CH_4 = 21 CO_2/CH_4 x (12 C / 44 CO_2)
Density of CH_4 = 19.2 g/ft^3
Btu content of CH_4 = 1,000 Btu/ft^3

[7] Although at this price, the catalytic oxidizer technology is cost-effective, a mine may still need to implement Options 1 and 2 for technical and safety reasons.

[8] At the less gassy mines, the low methane concentration make self-sustained oxidation impossible and supplemental gas is required to combust the gas. Because EPA’s analysis is based on the more gassy mines, the assumption that all methane emissions from ventilation air can be reduced cost-effectively does not have a major impact on the MAC results.

5. Livestock Manure Management

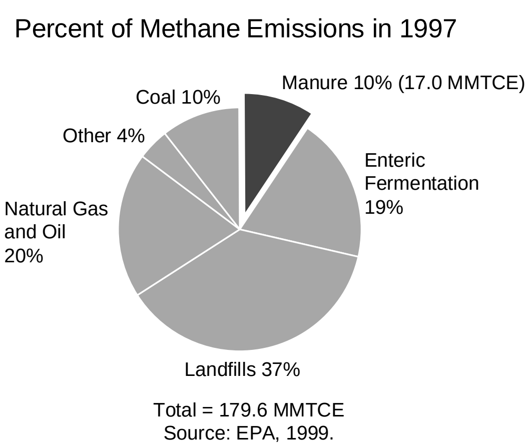
Summary

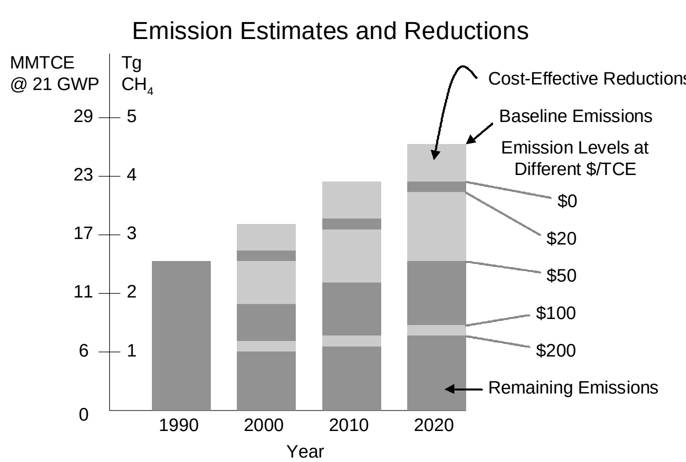
EPA estimates 1997 U.S. methane emissions from livestock manure management at 17.0 MMTCE (3.0 Tg), which accounts for ten percent of total 1997 U.S. methane emissions (EPA, 1999). The majority of methane emissions come from large swine (hog) and dairy farms that manage manure as a liquid. As shown below in Exhibit 5-1, EPA expects U.S. methane emissions from livestock manure to grow by over 25 percent from 2000 to 2020, from 18.4 to 26.4 MMTCE (3.2 to 4.6 Tg). This increase in methane emissions is primarily due to the increasing use of liquid and slurry manure management systems which generate methane. This use is associated with the trend toward larger farms with higher, more concentrated numbers of animals.

Cost-effective technologies are available that can stem this emission growth by recovering methane and using it as an energy source. These technologies, commonly referred to as anaerobic digesters, decompose manure in a controlled environment and recover methane produced from the manure. The recovered methane can fuel engine-generators to produce electricity or boilers to produce heat and hot water. Digesters also reduce foul odor and can reduce the risk of ground- and surface-water pollution. In addition, digesters are practical and often cost-effective for most large dairy and swine farms, especially those located in warm climates.

The AgSTAR Program, a voluntary EPA-industry partnership initiated under the Climate Change Action Plan (CCAP), has identified cost-effective opportunities that could reduce methane emissions by up to 3.2 MMTCE (0.6 Tg) in 2010 at current energy market prices, i.e., $0/ton of carbon equivalent ($0/TCE), as Exhibit 5-1 shows. Greater methane reductions could be achieved with the addition of higher values per TCE. For example, EPA's analysis shows that in 2010, emission reductions could reach 4.5 MMTCE (0.8 Tg) with a value of $20/TCE added to the energy market price (in 1996 US$).

Exhibit 5-1: U.S. Methane Emissions from Livestock Manure Management (MMTCE)





1.0 Methane Emissions from Manure Management

Livestock manure is primarily composed of organic material and water. Anaerobic and facultative bacteria decompose the organic material under anaerobic conditions. The end products of anaerobic decomposition are methane, carbon dioxide, and stabilized organic material. Several biological and chemical factors influence methane generation from manure. These factors are discussed below. In addition, this section discusses the methods EPA uses to estimate methane emissions from manure in the U.S. Current and future emissions are presented as well as a discussion on the uncertainties associated with the emission estimates.

1.1 Emission Characteristics

The methane production potential of manure depends on the specific composition of the manure, which in turn depends on the composition and digestibility of the animal diet. The amount of methane produced during decomposition is also influenced by the climate and the manner in which the manure is managed. The management system determines key factors that affect methane production, including contact with oxygen, water content, pH, and nutrient availability. Climate factors include temperature and rainfall. Optimal conditions for methane production include an anaerobic, water-based environment, a high level of nutrients for bacterial growth, a neutral pH (close to 7.0), warm temperatures, and a moist climate.

Before the 1970s, methane emissions from manure were minimal because the majority of livestock farms in the U.S. were small operations where animals deposited manure in pastures and corrals. Manure management normally consisted of scraping and collecting the manure and later applying it as fertilizer to croplands, allowing manure to remain in constant contact with air.

Much larger dairy and swine farms have become more common since 1990. To collect and store manure at these large farms, farmers often use liquid manure management systems that use water to flush or clean alleyways or pits where the manure is excreted. This liquid and manure mixture is generally collected and stored until it can be applied to cropland using irrigation equipment. While in storage, the submerged manure generates methane.

Dairy and swine farms are typically the only livestock farms where liquid and slurry manure systems are used. Beef, poultry, and other livestock farms generally do not use liquid manure systems, and therefore produce much less methane.

The key factors affecting methane production from livestock manure are the quantity of manure produced, manure characteristics, the manure management system, and climate.

- **Quantity of Manure Production**. Manure production varies by animal type and is proportional to the animal's weight. A typical 1,400-pound dairy cow produces about 112 pounds of manure per day and a typical 180-pound hog produces about 11 pounds of manure per day.
- **Manure Characteristics**. Methane generation takes place in the volatile solids portion (VS) of the manure.[1] The VS portion depends on livestock type and diet. Animal type and diet also affect the quantity of methane that can be produced per kilogram of VS in the manure. This quantity is commonly referred to as "B_o" and is measured in units of cubic meters of methane per kilogram of VS (m^3 CH_4/kg VS). Manure characteristics are summarized in Appendix V, Exhibit V-1.
- **Manure Management System.** Methane production also depends on the type of manure management system used. U.S. producers use "dry" and "liquid" manure management systems. Dry systems include solid storage, dry feedlots, deep pit stacks, and daily spreading of the manure. In addition, unmanaged manure from animals grazing on pasture falls into this category. Liquid management systems use water to facilitate manure handling. These systems, known as liquid/slurry systems, use concrete tanks and lagoons to store flushed and scraped manure. The la-

goons are typically earthen structures such as ponds or lagoons. Both types of systems store manure until it is applied to cropland and create the ideal anaerobic environment for methane production. Up to half of the manure on large dairy farms and virtually all the manure on large hog farms is managed using liquid systems.

- **Climate.** Manure decomposes more rapidly when climate conditions encourage bacterial growth. For anaerobic manure systems, warm temperatures increase methane generation. Therefore, methane generation is greater in warm states such as California and Florida and lower in cool states such as Minnesota and Wisconsin. For dry manure management systems, wet climates have higher emissions than arid climates, though emissions in either case are very low.

The characteristics of manure systems and climate can be represented in a methane conversion factor (MCF) which quantifies the potential for emitting methane and has a range from zero to one. Manure systems and climates that promote methane production have an MCF near one. Conditions that do not promote methane production have an MCF near zero. Appendix V, Exhibit V-2 lists MCFs for different climates and manure management systems.

1.2 Emission Estimation Method

EPA estimates emissions by determining the amount and type of manure produced, the systems used to manage the manure, and the climate (Safley, et al., 1992; EPA, 1993).

As shown in the equation in Exhibit 5-2, the national emission estimate is the sum of emission estimates developed at the state level, for the relevant animal types and manure management systems. A detailed description of the emission estimation method is contained in Appendix V, Section V.1.

By developing state-level estimates, key differences in annual manure characteristics, populations, manure management practices and climate are incorporated into the analysis. EPA estimates manure production using livestock population data published by the U.S. Department of Agriculture (USDA). The American Society of Agriculture Engineers (ASAE) publishes volatile solid production rates each year. The current estimates use VS rates from the 1995 ASAE Standards (ASAE, 1995).

Exhibit 5-2: Methane Emissions Equation

$$CH_4 = \overset{\text{States}}{\sum_i} \; \overset{\text{Animal Types}}{\sum_j} \; \overset{\text{Manure Mgmt. System}}{\sum_k} Manure_{ij} \bullet MF_{ijk} \bullet VS_{ij} \bullet B_{oj} \bullet MCF_{ik}$$

CH_4	=	Methane generated (ft^3/day)
$Manure_{ij}$	=	Total manure produced by animal type *j* in state *i* (lb/day)
MF_{ijk}	=	Percent of manure managed by system *k* for animal type *j* in state *i*
VS_{ij}	=	Percent of manure that is volatile solids for animal type *j* in state *i*
B_{oj}	=	Maximum methane potential of manure for animal type *j* (ft^3/lb of volatile solids)
MCF_{ik}	=	Methane conversion factor for system *k* in state *i*

Methane generation potentials (B_o) were determined through laboratory research performed by Hashimoto and Steed (1992), and referenced in EPA (1993). EPA determined state-specific emission factors for dairy cows and swine based on the farm size distribution in each state (USDC, 1995) and system MCF values developed by Safley, et al. (1992) and Hashimoto and Steed (1992). Emission factors for other livestock types were also determined by Safley, et al. (1992) based on climate and manure management system usage.

The calculation of dairy cow emissions also includes a dry matter intake (Dmi) scaling factor to account for the improvement in the rations fed to dairy cows. Dairy farmers use more digestible feed in the diets of dairy cows to increase productivity. The improved feed also increases the proportion of VS available in the manure, increasing methane production on a per-animal basis.

1.3 Emission Estimates

EPA estimates current and historic emissions using reported data and available research. Future emissions are estimated using projections of livestock production and changes in manure management practices. The emissions estimates are described in detail in the following sub-sections.

1.3.1 Current Emissions and Trends

EPA estimates that 1997 U.S. methane emissions from livestock manure were 17.0 million metric tons of carbon equivalent (MMTCE) or 3.0 Teragrams (Tg), as shown in Exhibit 5-3 (EPA, 1999). Total emissions from manure have increased each year from 1990 to 1995. Emissions declined in 1996, but displayed a sharp rise in 1997, mostly due to fluctuations in the swine populations. Steady shifts in the dairy cattle population toward states with higher use of liquid systems caused an increase in emissions from this livestock category, despite a decrease in the dairy cattle population.

1.3.2 Future Emissions and Trends

EPA estimates future emissions using forecasts for two key factors: animal production and manure management practices.

- **Future Livestock Production**. Forecasts of livestock production are based on trends and projections of consumption of dairy and meat products, agricultural policy, and imports/exports. USDA forecasts short-term trends, usually six to seven years in the future. Taking into account improvements in productivity, EPA uses these USDA production forecasts to project long-term trends in livestock population to the year 2020. EPA assumes that as consumption of livestock products increases, the extent of intensive livestock production will increase to meet that demand. A 16 percent increase in swine production and a 17 percent increase in milk production is expected between 1997 and 2010.

- **Future Manure Management Practices.** Future manure management practices have a large impact on emission estimates. Because forecasts of future livestock manure management practices are not available in existing literature, EPA projects usage of manure management systems based on field experience. If the use of confined and intensive livestock production systems continues to increase, the use of liquid-based manure management systems will probably increase. Such systems are often preferred for large-scale livestock production systems because they allow for the efficient collection, storage, and, in some cases, treatment, of livestock manure. This shift towards liquid systems would result in significant increases in emissions because liquid systems produce considerably more methane than dry systems. However, due to increasing pressure to minimize water quality and odor problems, some producers are evaluating dry

Exhibit 5-3: Methane Emissions from Livestock Manure Management (MMTCE)

Animal Type	1990	1991	1992	1993	1994	1995	1996	1997
Dairy Cattle	4.3	4.3	4.4	4.4	4.5	4.6	4.5	4.6
Beef Cattle	1.1	1.2	1.2	1.2	1.2	1.3	1.3	1.3
Swine	7.8	8.2	8.6	8.6	9.1	9.2	8.9	9.3
Sheep	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Goats	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Poultry	1.5	1.5	1.6	1.6	1.7	1.7	1.7	1.8
Horses	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
TOTAL	**14.9**	**15.4**	**16.0**	**16.1**	**16.7**	**16.9**	**16.6**	**17.0**

Totals may not sum due to independent rounding.
Source: EPA, 1999.

systems and the use of grass-based dairies that may result in fewer liquid-based manure management systems.

Over the last twenty years the share of the dairy cattle population on large farms (greater than 500 cows) has risen from 8 to 18 percent. The proportion of hogs raised on large farms (greater than 1,000 hogs) has increased from 31 percent in 1987 to 50 percent in 1992, directly corresponding with increased use of liquid manure management systems (USDC, 1995). In 1995, 33 percent of all cattle manure and 75 percent of all hog manure was managed with liquid systems (EPA, 1993). The next statistical data point will be available when the next Census of Agriculture is available. Field experience indicates that the use of liquid systems is continuing to increase, perhaps at an accelerating rate.

The two key factors contributing to emission growth are increased manure volumes due to the expected growth in animal populations needed to meet forecast production levels, shown in Exhibit 5-4, and the growing use of liquid management systems. Based on livestock production projections, EPA estimates that manure production in 2020 will be seven percent higher than in 1990, and that 20 percent more manure will be managed in liquid systems. Exhibit 5-5 presents U.S. manure methane emission estimates for 2000 through 2020.

1.4 Emission Estimate Uncertainties

The major sources of uncertainty in the emissions estimates are manure management practice data and predictions of future production. These uncertainties are described in detail below.

1.4.1 Current Emissions

Uncertainties are associated with both the activity levels and the emission factors used in the emission analysis. The estimates of current animal populations and manure characteristics (volatile solids) are fairly certain because these data are regularly revisited and updated by reliable sources, e.g., USDA and ASAE. The methane production potential values, determined

Exhibit 5-4: U.S. Livestock Production

Animal Type	Units	1995	2000	2005	2010	2015	2020
Dairy Cattle	Billion lbs milk/yr	156	166	178	185	193	201
Beef Cattle	Billion lbs/yr	28	28	28	29	30	30
Swine	Billion lbs/yr	19	19	21	22	23	24
Poultry	Billion lbs/yr	5	5	5	5	5	5
Sheep	1,000 head	8,886	7,998	7,998	7,977	7,939	7,872
Goats	1,000 head	2,495	2,495	2,495	2,495	2,495	2,495
Horses	1,000 head	6,000	6,325	6,642	6,970	7,314	7,661

Source: 1995-2005 values are based on USDA, 1996; 2010-2020 are values from extrapolation analysis.

Exhibit 5-5: Projected Baseline Methane Emissions from Livestock Manure Management (MMTCE)

Animal Type	2000	2005	2010	2015	2020
Dairy Cattle	5.2	5.8	6.3	6.9	7.5
Beef Cattle	1.2	1.2	1.2	1.3	1.3
Swine	9.9	11.1	12.3	13.5	14.8
Sheep	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1
Goats	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1
Poultry	1.8	2.0	2.2	2.4	2.6
Horses	0.2	0.2	0.2	0.2	0.2
TOTAL	**18.4**	**20.4**	**22.3**	**24.3**	**26.4**

Totals may not sum due to independent rounding.

through laboratory research, are also relatively reliable. Greater uncertainty exists in the estimates of the amount of manure managed by each type of manure system and the estimates of the MCFs for each manure system. To best characterize the dairy and swine industry trends described in Section 1.3.1, farm-size distributions should be updated each year. Currently, however, farm-size distribution data are published by USDA every five years, which contributes to uncertainty in this factor. Finally, methane production between similar systems can vary widely. The research used to develop MCFs was extensive but does not completely account for this variability.

The uncertainties in manure methane emission estimates can be reduced by improving the characterization of livestock manure management practices and by improving the estimated MCFs. The current analysis utilizes published farm-size distribution data to reduce uncertainty in state manure management practices on dairy and swine farms. The next Census of Agriculture will be released in late 1999. Using this updated data will further improve this characterization. MCF estimates can be improved through additional field measurements over the complete range of practices and temperatures under which manure is managed. Measurements should focus on liquid systems because they are the largest source of manure methane emissions.

1.4.2 Future Emissions

In addition to the uncertainties associated with current emission estimates, future emission estimates are subject to uncertainty stemming from forecasts of future dairy and meat product consumption and productivity. USDA forecasts of future trends are the most reliable projections that exist for the U.S. However, many unpredictable factors can influence future production, such as global market changes that impact the demand for livestock exports.

Although the analysis of future emissions includes the impacts of increased dry matter intake by dairy cows, it does not include the impacts of changing feed for other livestock. These impacts may contribute to an underestimation of emissions for some livestock types, particularly for swine, where recent data shows a trend towards feed that increases VS production.

Additionally, accurately predicting future manure management system usage is difficult. In the near term, liquid system usage will continue to increase as the dairy and swine industries move toward larger production scales. However, potential regulations in livestock waste management may affect future management strategies. The extent and direction of the impact of such regulations is not yet known.

The uncertainty in estimates of future emissions will be reduced by improving forecasts of manure management characterization, based on on-going monitoring of trends and regulation. In addition, developing more accurate projections of livestock product demand and consumption will reduce the uncertainty of the future estimates.

2.0 Emission Reductions

EPA evaluates cost-effective methane emission reduction opportunities at livestock facilities. The analysis and discussion in this section focus on methane recovery and utilization. It first describes the technologies, costs, and potential benefits of methane recovery and utilization. These costs and benefits are then translated into emission reduction opportunities at various values of methane, which are used to construct a schedule of emission reductions and a marginal abatement curve (MAC).

2.1 Technologies for Reducing Methane Emissions

Reduction strategies focus on emissions from liquid systems because these systems have large methane emissions that can be feasibly reduced or avoided. Two general options exist for reducing emissions from liquid systems: (1) switching from liquid management systems to dry systems; or (2) recovering methane and utilizing it to produce electricity, heat or hot water. Only the option of recovering and utilizing methane is used in the cost analysis. Each option is described below.

2.1.1 Switch to Dry Manure Management

Methane production is minimal in dry, aerobic conditions. Switching from liquid to dry management systems would reduce methane emissions produced in liquid systems. However, such a shift is largely impractical for both environmental impact and process design reasons. Dry manure management systems can lead to significant surface and ground water pollution. In addition, the liquid manure management systems at large dairy and swine farms are integrated with the overall production process. Switching to dry systems would require a fundamental shift in the entire production scheme. For these reasons, EPA does not consider this option in this analysis.

2.1.2 Recover and Use Methane to Produce Energy

With the use of liquid-based systems, the only feasible method to reduce emissions is to recover the methane before it is emitted into the air. Methane recovery involves capturing and collecting the methane produced in the manure management system. This recovered methane can be flared or used to produce heat or electricity.

Electricity generation for on-farm use can be a cost-effective way to reduce farm operating costs. The generated electricity displaces purchased electricity, and the excess heat from the engine displaces propane. The economic feasibility of electricity generation usually depends on the farm's ability to use the electricity generated on-site. Selling the electricity to an electric power company has seldom been economically beneficial because the utility buy-back rates are generally very low.

Three methane recovery technologies are available. Covered anaerobic digesters may be used at farms that have engineered ponds for holding liquid waste. Complete-mix and plug-flow digesters can be used for other farms. Each system attempts to maximize methane generation from the manure, collect the methane, and use it to produce electricity and hot water. Methane recovery also significantly reduces odor, which is important for many facilities.

- **Covered Anaerobic Digesters.** Covered anaerobic digesters are the simplest type of recovery system and can be used at dairy or swine farms in temperate or warm climates. Larger dairies and swine farms often use lagoons as part of their manure-management systems. Recovering methane usually requires an additional lagoon (primary lagoon), a cover, and a collection system. The primary lagoon is covered for methane generation and a secondary lagoon is used for wastewater storage. Manure flows into the primary lagoon where it decomposes and generates methane. The methane is collected under the cover and used to power an engine-generator. Waste heat from the generator is used for on-farm heating needs. The digested wastewater flows into the secondary lagoon where it is stored until it can be applied to cropland. A two-lagoon system also provides added environmental benefits over a single-lagoon system, including odor and pathogen reduction. This technology is often preferred in warmer climates and/or when manure must be flushed as part of on-going operations.

- **Complete-Mix Digesters.** Complete-mix digesters are tanks into which manure and water are added regularly. As new water and manure are flushed into the tank, an equal amount of digested material is removed and transferred to a lagooon. The digesters are mixed mechanically on an intermittent basis to ensure uniform digestion. The average retention time for wastewater in the tanks is 15 to 20 days. As manure decomposes, methane is generated and collected. To speed decomposition, waste heat from the utilization equipment heats the digesters. Complete-mix digesters can provide digestion and methane production at both dairy and swine farms. However, they are not recommended for use at dairy farms because of the high solids content of dairy manure. Complete-mix digesters are typically used at swine farms in colder climates where lagoons cannot produce methane year-round.

- **Plug-Flow Digesters.** Plug-flow digesters consist of a long concrete-lined tank where manure flows through in batches, or "plugs." As new manure is added daily at the front of the digesters, an equal amount of digested manure is pushed out the far end. One day's manure plug takes about 15 to 20 days to travel the length of the digesters. Methane is generated during the process and then collected. To speed decomposition, waste heat from the utilization equipment heats the digester tank. Plug-flow digesters are almost always used at dairies where the consistency of the cow manure allows for the formation of "plugs." Swine manure, as excreted, does not possess the proper density to use in this system. Manure digestion using plug-flow digesters also provides the added benefit of digested solids, which can be recovered and used as a soil amendment or bedding for cows.[2] Plug-flow digesters are generally used in colder climates or at newly constructed dairies instead of lagoons.

  Estimating methane recovery from plug-flow digesters requires information on management system usage at farms that may decide to install these digesters. Plug-flow digesters generally receive manure as excreted, which is usually scraped into the digester. It is uncertain whether this scraped manure would otherwise be handled using a liquid system or simply stored or spread as a solid. Because manure handled as a solid produces very little methane, the emission reduction from plug-flow digesters can be minimal, depending on climate and waste systems. Additionally, it is also unclear whether dairies that currently flush manure to lagoons would switch to scraping manure to plug-flow digesters. Moreover, a significant portion of the revenue from plug-flow digester systems can arise from sales of the separated fiber. This opportunity is dependent on securing buyers for the fiber and negotiating a reasonable price. Due to these complexities, emission reductions from dairies are only estimated for covered lagoons.

2.2 Cost Analysis of Emission Reductions

The cost analysis for reducing manure methane emissions focuses on methane recovery because it is generally the most feasible and cost-effective reduction option. Emission reductions are estimated to be the amount of manure methane that can be cost-effectively recovered at a variety of energy prices and emission reduction values.

The costs of methane recovery vary depending on the recovery and utilization option chosen and the size of the farm. The general costs of recovery and electricity generation are explained below and summarized in Exhibit 5-6. Exhibit 5-7 summarizes the break-even or cost-effective herd size for different digester projects.

Exhibit 5-6: Methane Recovery System Costs

Digester Capital Costs	
Digester Type	**Cost ($/animal)**
Covered Digester	
Dairy	$245 - $380/cow
Swine	$130 - $220/hog
Complete-mix Digester	
Dairy	$235 - $410/cow
Swine	$130 - $260/hog
Engine-Generator Capital Costs	
Digester Type	Cost ($/kW)
Lagoon Digester	$750/kW
Complete-mix Digester	$750/kW

Source: EPA, 1997a.

Exhibit 5-7: Economics of Digester Projects

	Break-Even Herd Size	Cost	Annual Revenue
Dairy			
Covered Lagoon	500	$150,000	$29,000
Complete-mix	700	$188,000	$34,000
Hog			
Covered Lagoon	1,350	$193,000	$39,000
Complete-mix	2,500	$332,000	$62,200

Source: EPA, 1997a.

EPA developed average costs based on actual project costs from recent AgSTAR charter farm projects as well as the AgSTAR FarmWare software, a project analysis software tool used to assess project feasibility.[3] A detailed cost breakdown is shown in Appendix V, Exhibits V-3, V-4 and V-5.

2.2.1 Costs

EPA estimates the opportunity to reduce emissions by evaluating the potential for farmers to cost-effectively build and operate anaerobic digester technologies (ADTs). The costs associated with installing and running the ADTs vary by system type and the volume of manure that is to be handled. General costs for each technology are described below.

Covered Anaerobic Digester. The cost of this system includes the cost of the primary lagoon, its cover, and the gas piping needed to deliver the gas to the utilization equipment. For dairy farms, these costs are between $245 and $380 per milk cow. For large hog farms (more than 1,000 head), the range is between $130 and $220 per hog.

Complete-Mix Digester. The cost of the complete-mix digester includes the cost of the vessel, the heat exchange system, the mixing system, and the gas piping needed to deliver the gas to the utilization equipment. For dairy farms, the digester costs between $235 and $410 per milk cow. For large hog farms, the digester costs range between $130 and $260 per hog.

Engine-Generator. Engine-generators are sized for the available gas flow from the methane recovery system. The cost of an engine-generator on a dairy farm is roughly between $160 and $260 per cow. For large hog farms, the engine-generator costs between $32 and $90 per hog. An engine-generator for an anaerobic digester, including the heat exchanger, costs about $750/kW.

2.2.2 Cost Analysis Methodology

To develop a MAC, EPA evaluated a range of energy prices along with a range of emission reduction values in $/ton of carbon equivalent ($/TCE) where manure methane emissions can be cost-effectively reduced. EPA conducted the analysis for the years 2000, 2010, and 2020. The steps in the analysis follow below.

Step 1: Define a "Model" Facility. Typical methane recovery and utilization systems are defined for each of the two ADTs used in the analysis:

- **Covered Anaerobic Digester.** EPA defines a covered anaerobic digester system to include a new lagoon, a cover for the lagoon, a methane collection system, a gas transmission and handling system, and an engine-generator. The sizes of these components are estimated based on the amount of manure handled, the hydraulic retention time for the manure required in the specific climate area analyzed, and the amount of gas produced. A new lagoon is assumed to be required in all cases even though some farms may have lagoons that are suitable for covering. This assumption makes the analysis conservative since it includes a cost that may not be necessary.
- **Complete-Mix Digester.** A complete-mix digester is defined to include the digester vessel and cover, digester heating system, methane collection system, gas transmission and handling system, and an engine-generator. The sizes of these components are estimated based on the amount of manure handled. The system is designed to produce a 20-day hydraulic retention time for the manure. No costs are included for modifying the existing manure management practices to conform to the minimal water requirements of the complete-mix digester.

Step 2: Define "Model" Manure Management Practices. The amount of manure managed in liquid management systems, such as lagoons, determines methane emissions and methane reduction potential. Although manure management practices can vary significantly, the large dairy and swine farms that generate most of the methane emissions and mitigation opportunities will generally use liquid or slurry systems. The "model" manure management practices chosen for dairy and swine farms are described for each below.

- **Dairy Farms.** Generally, large dairy farms either flush or scrape their manure to a central location, such as a lagoon or digester. Although the proportion of dairy manure that is handled in liquid systems for a given farm can vary, this analysis uses a national average of 55 percent (EPA, 1997b). For this analysis, EPA assumes that covered lagoon systems on dairy farms can accept the entire 55 percent of manure that can be handled in liquid systems.
- **Swine Farms.** Most large swine farms use liquid flush systems to manage their manure. For this analysis, EPA assumes that all of the manure produced on large swine farms can be managed in covered lagoon or complete-mix digester systems to produce methane.

Step 3: Develop the Unit Costs for the System Components. Unit costs for the system components are taken from FarmWare (EPA, 1997a), the EPA-distributed software tool used to assess project feasibility. The component unit costs and total costs for typical projects are shown in Appendix V, Exhibits V-3 to V-5. As shown in the exhibits in the appendix, covered lagoon systems are typically less costly to build than complete-mix and plug-flow digester systems.

Step 4: Determine Farmer Revenue. The revenues accruing to the farmer are the value of the energy produced and the value of the emission reduction. Electricity production is estimated based on the amount of biogas produced and the heat rate of the engine (14,000 Btu/kWh). Biogas production at each facility is modeled using FarmWare (EPA, 1997a) and accounts for the amount and composition of the manure managed in the lagoon, the lagoon hydraulic retention time, the lagoon loading rate, and the impact of local temperature on the methane production rate for lagoon systems. Biogas is assumed to be 60 percent methane and 40 percent carbon dioxide and other trace constituents. The value of the electricity is estimated using published state average commercial electricity rates (EIA, 1997). These rates are reduced by \$0.02/kiloWatt-hour (kWh) to reflect electricity prices that farmers would likely be able to negotiate with their local energy providers. This conservative rate reduction is adopted even though the electricity produced displaces on-site electricity usage; experience has shown that inter-connect charges and demand charges can limit the amount of the energy savings realized.

In addition to the electricity produced, the annual value of heat recovery from the engine exhaust is estimated at \$8/cow at dairy farms. This energy is used for heating wash water and other heating needs and displaces natural gas or propane. This value is a conservative estimate based on actual projects at dairy farms. The heat recovery value for swine farms is estimated to be 20 percent of the value of the electricity produced, based on current projects. This heat is needed for farrowing facilities and nurseries, with less required for growing and finishing operations.

The value of the emission reduction is estimated as the amount of methane recovered times \$/TCE. For modeling purposes, the emission reduction value is converted into an added value to the electricity produced and modeled as additional savings realized by the farmer. This conversion is performed using methane's Global Warming Potential (GWP) of 21, the heat rate of the engine, and the energy content of methane (1,000 Btu/cubic foot).[4]

Step 5: Determine Break-Even Farm Sizes. EPA conducted a discounted cash flow analysis for each climate division in the U.S. to estimate the smallest farm size in each climate division that can cost-effectively install and operate each of the three ADTs.[5] Swine and dairy farms are analyzed separately and farm size is measured in terms of the number of head of milk-producing cows for dairies and the total number of animals for swine farms. As the number of head increases, the sizes and costs of the system components also increase. The amount of manure managed and biogas produced also increase with farm size.

The break-even farm size is the smallest number of animals required to achieve a net present value (NPV) of zero using a real discount rate of ten percent over a ten year project life.[6] The electricity value in each climate division is the state average minus \$0.02/kWh as discussed above in Step 4. The break-even farm size is estimated for each climate division for each combination of electricity price and emission reduction value. At higher electricity prices and emission reduction values, smaller farms can implement the projects cost-effectively.

Step 6: Estimate Emission Reductions. EPA estimates national emission reductions separately for swine and dairy farms for each combination of electricity price and emission reduction value using the break-even farm sizes from Step 5. First, break-even farm sizes are assigned to each county by mapping the counties into the climate divisions. Second, the portion of dairy cows and swine on farms that are greater than the break-even size is estimated for each county using the distribution of farm sizes in each county (USDC, 1995). For covered digesters and complete-mix digesters, emission reductions for each county are estimated as the emissions from this portion of the dairy cows and swine.

EPA estimates the total emission reductions from swine farms by combining the results for the covered digesters and the complete-mix digesters. In each county, the preferred technology, based on a break-even electricity price, is assumed to be implemented. The emission reductions using the preferred system are summed across all the counties and divided by the total national emissions to estimate the percent emission reductions.

Step 7: Estimate Reductions from Odor Control. As discussed above, some swine farms cover their lagoons to reduce odor. U.S. EPA's AgSTAR program has identified odor control as the principal motivation behind several recently installed covered digesters and one heated mix digester on swine farms. The reasons driving these installations are site-specific and are not reflected in the analysis. As a result, the analysis assumes that a minimum emission reduction of ten percent of total emissions will be achieved at all swine farms for odor control purposes. However, the costs of these emission reductions are not included in the analysis.

Step 8: Generate the Marginal Abatement Curve. The MAC displays cost-effective methane abatement at each combination of electricity price and carbon equivalent value for dairy and swine facilities. Exhibit 5-8 presents methane abatement at each of the additional emission reduction values.

2.3 Achievable Emission Reductions and Marginal Abatement Curve

EPA uses the above analysis to estimate the amount of methane emissions that could be reduced cost effectively at various energy values and avoided emissions in terms of carbon equivalent.

Exhibit 5-8 presents cost-effective emission reductions at various prices per TCE for 2010. The electricity prices shown are a weighted average of the state average retail electricity prices based on livestock population. Exhibit 5-9 and Exhibit 5-10 present the MACs for dairy cows and swine manure management systems, respectively. These curves are derived from the values shown in Exhibit 5-8. The MACs can also be referred to as cost or supply curves because they indicate the marginal cost per emission reduction amount. Energy market prices are aligned with $0/TCE given that this price represents no additional values for abated methane and where all price signals come only from the respective energy markets. The “below-the-line” reduction amounts, with respect to $0/TCE, illustrate this dual price-signal market, i.e., energy market prices and emission reduction values. Exhibit 5-11 presents total methane abatement at each value of carbon equivalent based on total manure methane emissions. These values are presented in the MAC provided in Exhibit 5-12. Exhibit 5-13 presents the cumulative emission reductions at selected values of carbon equivalent in 2000, 2010, and 2020.

In general, at higher methane values of $/TCE, investing in manure management systems for smaller farms becomes more cost-effective, i.e., the break-even farm size decreases. The break-even farm size varies by climate zone (temperature, precipitation) and size distribution of the farm by state. To simplify the presentation, EPA summed the total achievable reductions (from all farms) at each value of carbon equivalent to generate the MAC. This process was done separately for dairy cattle and swine.

Exhibit 5-8: Schedule of Methane Emission Reductions for Dairy and Swine Manure Management in 2010							
Manure Type	Label on MAC	Value of Carbon Equivalent ($/TCE)	Electricity Price with Additional Value of Carbon Equivalent ($/kWh)	Average Break-Even Farm Size (# of head)	Incremental Reductions (MMTCE)	Cumulative Reductions (MMTCE)	Cumulative Reductions (% of base)
DAIRY COW:	A	($30)	$0.04	1,025	0.23	0.23	4%
	B	($20)	$0.06	1,134	0.52	0.75	14%
	C	($10)	$0.07	828	0.33	1.07	20%
	D	$0	$0.09	753	0.88	1.95	36%
	E	$10	$0.10	787	0.29	2.24	41%
	F	$20	$0.12	733	0.27	2.51	46%
	G	$30	$0.14	654	0.19	2.70	49%
	H	$40	$0.15	575	0.17	2.87	52%
	I	$50	$0.17	521	0.14	3.01	55%
	J	$75	$0.21	414	0.37	3.38	62%
	K	$100	$0.25	294	0.38	3.76	68%
	L	$125	$0.29	219	0.31	4.07	74%
	M	$150	$0.34	172	0.26	4.33	79%
	N	$175	$0.38	140	0.24	4.57	83%
	O	$200	$0.42	114	0.21	4.78	87%
SWINE:	A	($30)	$0.02	> 20,000	1.23	1.23	10%
	B	($20)	$0.03	> 20,000	0.00	1.23	10%
	C	($10)	$0.05	5,112	0.00	1.23	10%
	D	$0	$0.07	5,120	0.00	1.23	10%
	E	$10	$0.08	3,906	0.00	1.23	10%
	F	$20	$0.10	4,339	0.79	2.02	16%
	G	$30	$0.12	2,990	2.25	4.28	35%
	H	$40	$0.13	1,932	1.36	5.63	46%
	I	$50	$0.15	1,390	1.10	6.74	55%
	J	$75	$0.19	821	3.52	10.26	83%
	K	$100	$0.23	602	0.51	10.77	88%
	L	$125	$0.27	510	0.25	11.03	90%
	M	$150	$0.32	500	0.01	11.04	90%
	N	$175	$0.36	500	0.00	11.04	90%
	O	$200	$0.40	500	0.00	11.04	90%

At $0/TCE, approximately $0.09/kWh for dairy and $0.07/kWh for swine, manure methane emissions could be reduced by about 3.2 MMTCE (dairy (2.0 MMTCE) plus swine (1.2 MMTCE)) or 0.6 Tg (dairy (0.3 Tg) plus swine (0.2 Tg)). At an additional carbon value equivalent of $20/TCE, 2010 methane emissions from livestock manure could be reduced by 4.5 MMTCE (dairy (2.5 MMTCE) plus swine (2.0 MMTCE)) or about 0.8 Tg (dairy (0.4 Tg) plus swine (0.4 Tg)). Dairy emission reductions are relatively elastic throughout the series. Swine emission reductions, which include a ten percent reduction minimum (explained in Section 2.2.2), remain at this level (1.2 MMTCE) until $20/TCE, when reductions begin to increase. At and above $125/TCE, however, swine manure emission reductions reach an upper bound at about 11.0 MMTCE (1.9 Tg).

Exhibit 5-9: Marginal Abatement Curve for Methane Emissions from Dairy Cow Manure Management in 2010

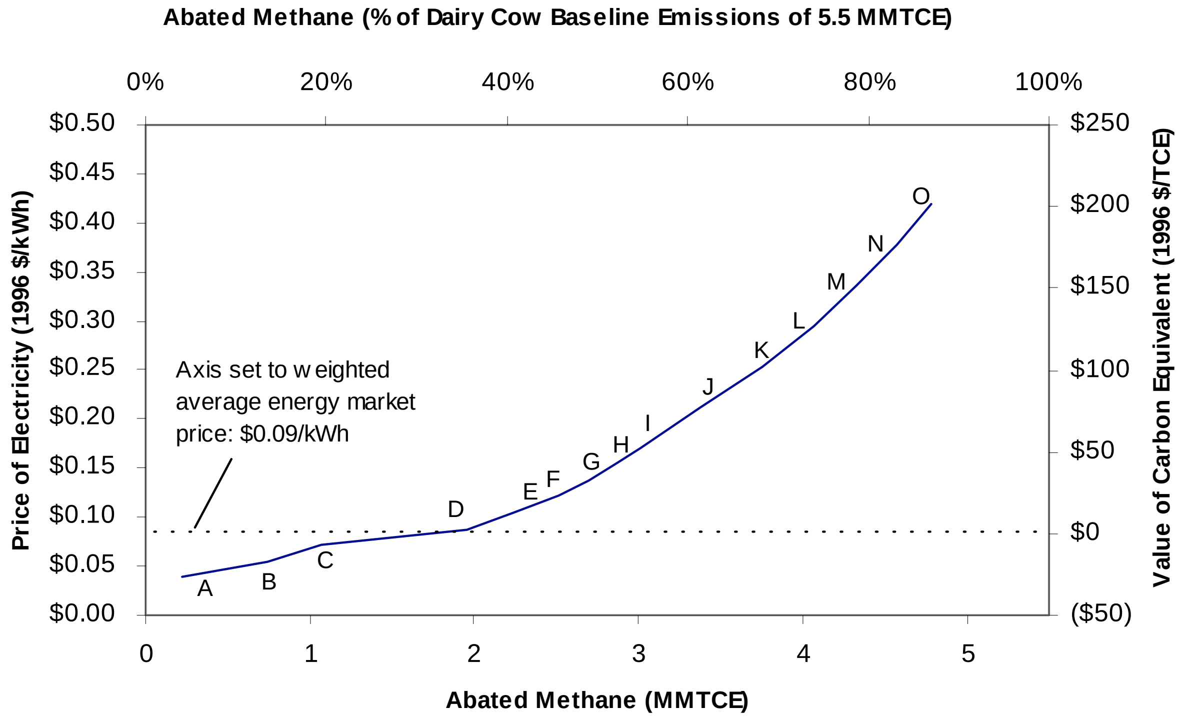


Exhibit 5-10: Marginal Abatement Curve for Methane Emissions from Swine Manure Management in 2010

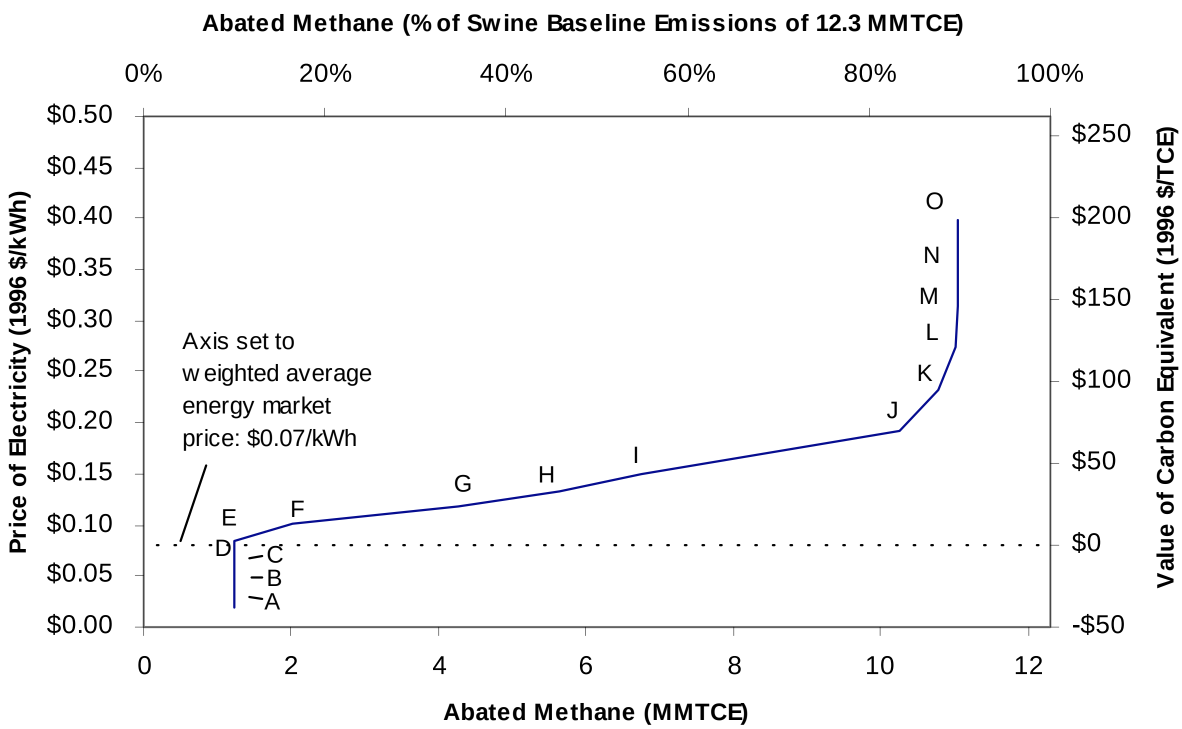


Exhibit 5-11: Schedule of Total Methane Emission Reductions in 2010			
Value of Carbon Equivalent ($/TCE)	Incremental Reductions (MMTCE)	Cumulative Reductions (MMTCE)	Cumulative Reductions (% of base)
($30)	1.45	1.45	7%
($20)	0.52	1.98	9%
($10)	0.33	2.30	10%
$0	0.88	3.18	14%
$10	0.29	3.47	16%
$20	1.06	4.53	20%
$30	2.44	6.98	31%
$40	1.52	8.50	38%
$50	1.25	9.75	44%
$75	3.89	13.64	61%
$100	0.89	14.53	65%
$125	0.57	15.10	68%
$150	0.27	15.37	69%
$175	0.24	15.61	70%
$200	0.21	15.82	71%

Exhibit 5-12: Marginal Abatement Curve for Methane Emissions from All Livestock Manure Management in 2010

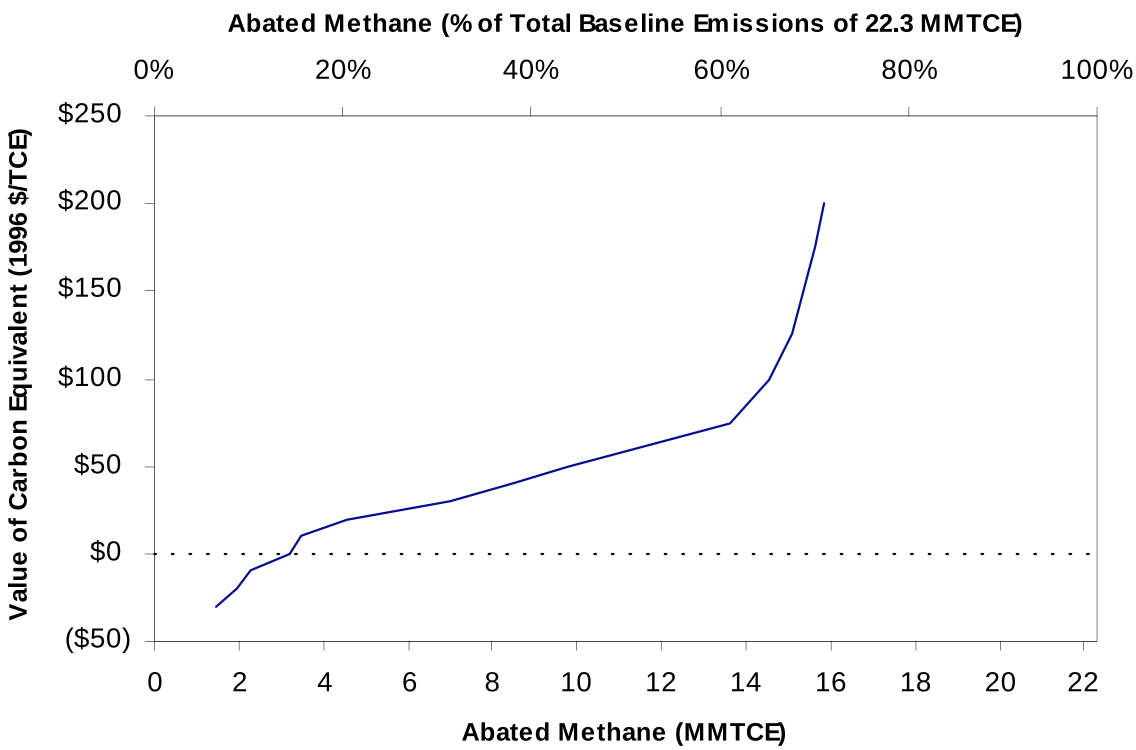


Exhibit 5-13: Emission Reductions at Selected Values of Carbon Equivalent in 2000, 2010, and 2020 (MMTCE)

	2000	2010	2020
Baseline Emissions	18.4	22.3	26.4
Cumulative Reductions			
at $0/TCE	2.5	3.2	3.9
at $10/TCE	2.7	3.5	4.2
at $20/TCE	3.6	4.5	5.5
at $30/TCE	5.6	7.0	8.5
at $40/TCE	6.8	8.5	10.3
at $50/TCE	7.8	9.7	11.8
at $75/TCE	10.9	13.6	16.5
at $100/TCE	11.6	14.5	17.6
at $125/TCE	12.1	15.1	18.3
at $150/TCE	12.3	15.4	18.6
at $175/TCE	12.5	15.6	18.9
at $200/TCE	12.6	15.8	19.2
Remaining Emissions	5.7	6.5	7.3

2.4 Reduction Estimate Uncertainties and Limitations

Uncertainties in the emission reduction estimates are due to the assumptions used to develop the model farm facility, the variability in the value of the methane recovered, and the incorporation of trends.

Site-specific factors influence the costs and benefits of recovering and using methane from livestock manure. In particular, the methane recovery system must be built so that it is completely integrated with the farm's manure management system. Costs and benefits of methane recovery are well documented. However, this analysis relies on a single model facility and is not customized to individual farm requirements. Thus, it may under- or over-estimate the cost-effectiveness of emission reductions at individual farms. Additionally, system prices are subject to change based on fluctuations in the construction industry, as well as the cost of biogas-fueled engine-generators. Such changes cannot be accurately predicted. Moreover, the analysis does not take into account possible changes in capital and operation and maintenance (O&M) expenses for emission reduction estimates in future years (2010, 2020). This may overstate benefits in the projection period.

For low emission reduction values the principal benefit of the anaerobic digester technology is the value of the electricity produced, which depends on the rate negotiated with the farm's electric service provider. Consequently, the value is considered uncertain in this analysis. Because this value can vary as often as the amount of projects, accurately determining electricity values for this analysis is difficult. EPA estimates the values as $0.02/kWh below state average commercial electricity prices. However, under restructuring of the electric power industry, a premium value may be realized for electricity produced from renewable resources such as methane. The potential impact of this premium is not included in this analysis.

Some recent projects at swine farms have been initiated primarily to reduce odor rather than produce electricity. These projects may signal a trend towards the growing importance of odor reduction at these facilities. Once quantified, including odor reduction benefits in the analysis will improve the estimates of emission reduction.

As discussed before, EPA estimates the emission reduction potential based in part on the distribution of dairy and swine farm sizes as measured by numbers of head. The farm size distribution data divide the farm sizes into a relatively small number of categories. The precision of the estimates would be improved with more refined farm size categories.

Finally, the distribution of farm sizes has changed significantly over the past ten years, particularly in the swine industry. Since 1992, the most recent year for which farm size data are available, the trend toward larger dairy and swine farms has continued. Consequently, the analysis likely under-estimates the portion of livestock on large farms as of 1997. Because emissions can more easily be reduced on large farms, the analysis also likely under-estimates the emission reduction potential. Given that the trend toward larger farms is expected to continue, applying this MAC to future baseline emissions likely under-estimates cost-effective emission reductions.

3.0 References

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4.0 Explanatory Notes

[1] Volatile solids (VS) are the organic fraction of total solids in manure that will oxidize and be driven off as gas at a temperature of 600°C.

[2] For plug-flow digesters, fiber can be recovered using a separator and sold for about $4 to $8/cubic yard ($yd^3$) as a soil amendment. At larger farms the cost of the separator (approximately $50,000) is more than offset by the value of the fiber, making this addition to the system profitable. The ability to realize these benefits is contingent on finding a reliable buyer for the fiber material.

[3] FarmWare can be downloaded from the AgSTAR homepage at www.epa.gov/agstar. Additional information on these digesters can be requested from EPA (EPA, 1997b).

[4] $/ton carbon equivalent ($/TCE) is converted to $/kWh by converting carbon into methane equivalent amounts based on the Global Warming Potential (21), then by converting methane to Btu, and finally, by converting BTU to kWh based on the average engine efficiency. The formula used to perform this conversion is shown below.

$$\frac{\$}{TCE} \; x \; \frac{10^6\ TCE}{MMTCE} \; x \; \frac{5.73\ MMTCE}{Tg\ CH_4} \; x \; \frac{Tg}{10^{12}\ g} \; x \; \frac{19.2\ g\ CH_4}{ft^3\ CH_4} \; x \; \frac{ft^3}{1{,}000\ Btu} \; x \; \frac{14{,}000\ Btu}{kWh} = \frac{\$}{kWh}$$

Where: 5.73 MMTCE/Tg CH_4 = 21 CO_2/CH_4 x (12 C / 44 CH_4)
Density of CH_4 = 19.2 g/ft^3
Btu content of CH_4 = 1,000 Btu/ft^3
Heat rate of IC Engine = 14,000 Btu/kWh

[5] The National Climatic Data Center (NCDC) defines up to 10 climate divisions in each state. Each climate division represents relatively homogenous climate conditions. For purposes of this analysis, the climate division monthly average temperatures are used to estimate biogas production from lagoons. The lagoon hydraulic retention time and the maximum loading rate are set based on the area temperature as described in EPA (1997b). Climate does not affect gas production from plug-flow and complete-mix digesters because they are heated.

[6] A ten percent real discount rate is used to reflect the return required by the farmer for this type of investment. In particular, the ADT systems are not integral to the farmer's primary food production business, and, consequently, are estimated to require a higher rate of return than normal investments by the farmer.

6. Enteric Fermentation

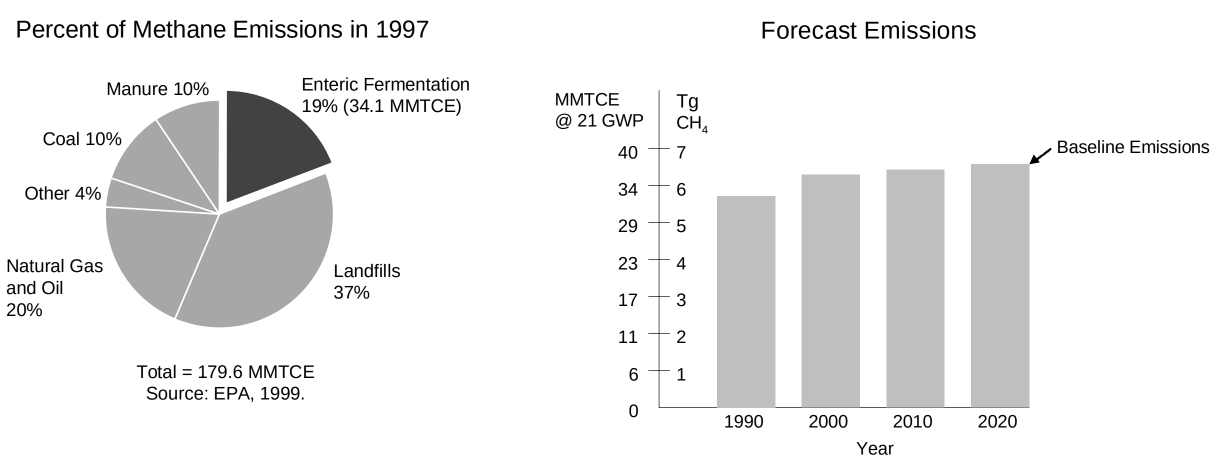
Summary

EPA estimates 1997 U.S. methane emissions from livestock enteric fermentation at 34.1 MMTCE (6.0 Tg), which accounts for 19 percent of total U.S. methane emissions in 1997. EPA expects methane emissions from livestock enteric fermentation to increase through 2020 as livestock populations grow to meet domestic and international demand for U.S. livestock products. In 2010, methane emissions are forecasted to reach 36.6 MMTCE (6.4 Tg) as shown below in Exhibit 6-1.

When estimating methane emissions from livestock enteric fermentation, EPA categorizes livestock populations, collects population data, and develops emission factors that account for the diversity of feed and animal characteristics throughout the U.S. Among livestock, cattle are examined more closely than other livestock species because they are responsible for the majority of U.S. livestock emissions, and significant variation exists in feed and animal characteristics for cattle. The greatest opportunity for reducing methane emissions from cattle is to increase production efficiency through improved management techniques.

This chapter describes methane emissions from livestock enteric fermentation, the methodology used to estimate methane emissions, and the approaches underway to reduce emissions from cattle. Cost-effective management practices and techniques can be used to improve animal health and nutrition, increase production efficiency, and reduce methane emissions per unit of product. Based on assumptions about the use of these practices to improve productivity, EPA has developed three scenarios (low, middle, and high) of future emissions from livestock enteric fermentation. Unlike other chapters in this report, no cost estimates have yet been developed for methane reductions from enteric fermentation.

Exhibit 6-1: U.S. Methane Emissions from Enteric Fermentation (MMTCE)



1.0 Methane Emissions from Enteric Fermentation

Livestock emit methane as part of their normal digestive processes. The U.S. livestock population consists of ruminant livestock (cattle, sheep, and goats), monogastric livestock (pigs), and pseudo-ruminants (horses and mules). Cattle emit more than 90 percent of the methane from livestock. The amount of methane produced is influenced significantly by animal and feed characteristics.

This section describes the source of methane emissions from livestock enteric fermentation and the method EPA uses to estimate emissions. The emission estimates and sources of uncertainty also are presented.

1.1 Emission Characteristics

Methane emissions from enteric fermentation depend on animal type and diet. This chapter primarily focuses on emissions from ruminant livestock.

Ruminant Livestock. Cattle, sheep, and goats are the primary ruminant livestock in the U.S. These animals produce more methane per unit of feed consumed than monogastric and pseudo-ruminant animals. Plant material consumed by ruminant livestock is fermented by approximately 200 species of microbes in the rumen, the first of a four-part stomach. The microbes convert the plant material into nutrients that livestock can use, such as volatile fatty acids. Methane, a by-product of this fermentation process, is released to the atmosphere mainly via the mouth and nostrils.

Methane from ruminant livestock is derived from a portion of the carbon energy in an animal's diet. Consequently, methane emissions generally decrease when production efficiency increases because a greater portion of feed energy consumed goes to production (milk or meat) rather than for methane.

Monogastric Animals and Pseudo-Ruminants. These animals contribute a comparatively small proportion of the total methane emitted by livestock in the U.S. Monogastric animals (pigs) do not have a rumen, but produce small amounts of methane during digestion. Pseudo-ruminants (horses and mules) produce less methane than ruminant livestock and more methane than monogastric animals. Pseudo-ruminants do not have a rumen, but feed is fermented during digestion, which allows them to obtain important nutrients from coarse plant material.

1.2 Emission Estimation Method

Animal and feed characteristics have a significant impact on methane emissions. Consequently, methods used to estimate methane emissions from livestock incorporate information on animal and feed characteristics. The factors affecting methane emissions, and the methods used to estimate past, current, and future emissions are described below.

1.2.1 Factors Affecting Methane Emissions from Enteric Fermentation

Methane emissions are a function of the size of the animal population, the quantity of feed consumed, and the efficiency by which an animal converts feed to product. The lower the efficiency, the greater the amount of methane emitted.

Improving animal productivity decreases methane emissions per unit of product. At the basic level, feed goes to maintenance and product. Maintenance is the proportion of feed needed to satisfy the basic metabolic requirements that keep the animal alive. A significant fraction of the methane emitted by cattle (40 to 60 percent) comes from the proportion of the feed used for maintenance (EPA, 1993b). The remaining feed energy is used for production. Maintenance requirements generally remain constant. Consequently, as maintenance remains constant and animal productivity increases, methane emissions go up slightly, but methane emissions per unit of product decrease.

Increasing animal productivity also reduces the number of animals needed to satisfy demand. By increasing productivity, i.e., producing more meat or milk per animal, meeting national demand for products is possible with fewer animals. As a result, overall methane emissions decrease. In the U.S., the dairy industry has demonstrated the impact of improved productivity on methane emissions. Between 1960 and 1990, the dairy industry increased annual milk production by ten million tons with 7.4 million fewer cows, reducing estimated methane emissions by almost one million metric tons of carbon (MMTCE) (USDA, 1990; EPA, 1993a).

Dairy and beef producers can increase production efficiency by improving feed conversion efficiency, which is defined as the efficiency by which feed is converted to product. Feed conversion efficiency is influenced by feed type. For example, grain feeds are converted to product more efficiently than forages, such as hay, because they are more digestible and are higher in protein.

1.2.2 Method for Estimating Current Methane Emissions

Emissions are estimated for cattle, sheep, goats, pigs, and horses. The methods used to estimate emissions are presented below. Information on the emission factors are presented in Appendix VI, Section VI.2. Methane emissions from livestock in the U.S. are estimated by: (1) dividing animals into homogenous groups; (2) developing emission factors for each group; (3) collecting population data; (4) multiplying the population by the emission factor for the respective group; and (5) summing emissions across animal groups and geographic regions (EPA, 1993a). The relationship between the emission factor estimate and the activity data is presented in the following equation:

$$CH_4 = \sum_{i}^{animal} \sum_{k}^{region} \left(EF_{ik}\right)\left(N_{ik}\right)$$

Where:

CH_4 = Total methane emissions (kg);

EF_{ik} = Emission factor for animal type *i* in region *k* (kg/animal); and

N_{ik} = Animal population for animal type *i* in region *k*.

Emission factors for different animal types are presented in Appendix VI in Exhibits VI-3 through VI-5.

EPA uses a variety of data sources to develop emission factors and estimate population sizes. Exhibit 6-2 presents the data sources for the emission factors and population data used to estimate methane emissions, in addition to criteria used to categorize the populations. Because management practices affect methane emissions, cattle are broken down into dairy and beef sectors. However, sheep, goats, pigs and horses are not broken down beyond the national level because they make up a small proportion of emissions from livestock.

1.2.3 Method for Estimating Future Methane Emissions

EPA develops future emission estimates based on assumptions regarding animal and feed characteristics.

Exhibit 6-2: Sources of Emission Factors and Population Data

Animal Type	Emission Factor	Population Data	Categorization
Dairy Cattle	Based on milk production data and on the model by Baldwin, et al. (1987a-b) [a]	USDA, 1998a,d [b]	Categorized by age, diet, and region [c]
Beef Cattle	Based on the model by Baldwin, et al. (1987a-b)	USDA, 1998a-c	Categorized by age, diet, and region
Sheep	Based on Crutzen, et al. (1986) [d]	USDA, 1998e	Not broken down beyond the national level
Goats	Based on Crutzen, et al. (1986)	USDA, 1998e	Not broken down beyond the national level
Pigs	Based on Crutzen, et al. (1986)	USDA, 1997	Not broken down beyond the national level
Horses	Based on Crutzen, et al. (1986)	FAO, 1998	Not broken down beyond the national level

[a] The model by Baldwin, et al. (1987) simulates digestion in growing and lactating cattle using information on animal and feed characteristics.

[b] The USDA National Agricultural Statistics Service collects data on the U.S. livestock population.

[c] Regions are West, North Central, South Central, North Atlantic, and South Atlantic.

[d] Crutzen, et al. (1986) developed emission factor estimates using information on typical animal size, feed intakes, and feed characteristics. Emission factors for developed countries are used for the U.S. inventory, as well as emission estimates in this analysis (EPA, 1999).

Source: EPA, 1999.

These assumptions differ by animal type and sector, and are summarized below.

Beef Cattle. Current emission factors (EPA, 1993a) are used to estimate future emissions from beef cattle. The beef cattle population is projected using future production estimates.

Dairy Cattle. For dairy cows, emission factors used to estimate future emissions are adjusted using projected milk production estimates. Consequently, future emission factors are estimated under the assumption that milk production per cow increases by 300 pounds per year (lbs/yr) through 2020. For dairy calves and replacement heifers, current emission factors (EPA, 1993a) are used to estimate future emissions.

The dairy cow population is estimated by taking net demand (including exports) and dividing it by the projected milk production per cow. Populations of calves and replacement heifers are estimated using the 1995 ratio of calves and replacement heifers to cows.

Sheep, Goats, Pigs, and Horses. Future population estimates are multiplied by current emission factors (EPA, 1993a) to estimate future emissions.

EPA estimates future animal populations using USDA projections through 2005 (USDA, 1996). Populations are projected beyond 2005 through 2020 for each species using the following assumptions.

- **Sheep.** Consumption of lamb/mutton is expected to decrease, causing a decrease in the sheep population.
- **Goats.** The goat population is expected to remain constant.
- **Pigs.** The pig population is expected to increase in response to increased consumption per capita.
- **Horses.** The horse population is calculated by estimating the future number of horses per capita, and multiplying it by the extrapolated human population.

1.3 Emission Estimates

The methods described in the previous section are used to estimate methane emissions from livestock enteric fermentation. This section presents emission estimates from 1990 to 1997, and projected estimates through 2020. Uncertainties in current and projected estimates are also discussed.

1.3.1 Current Emissions and Trends

U.S. livestock emitted 34.1 MMTCE (6.0 Tg) of methane in 1997. Cattle accounted for 96 percent of these emissions (32.6 MMTCE or 5.7 Tg) and sheep, goats, pigs, and horses for the remainder (1.5 MMTCE or 0.3 Tg). Exhibit 6-3 presents emissions for 1990 to 1997. Emissions from cattle increased by five percent from 1990 to 1997.

During 1990 to 1997, emissions from dairy cattle fell slightly. The main factor slowing the growth in emissions was the decrease in the cow and replacement heifer populations because of increased production efficiency in the dairy industry. As production efficiency increases, fewer animals are required to satisfy demand, and total methane emissions decrease.

As presented in Exhibit 6-3, beef cattle accounted for approximately 75 percent of cattle emissions in 1997. The growth in total emissions over the 1990 to 1997 period is largely due to an increase in emissions from beef cattle. This increase is driven primarily by an increase in the demand for beef, which is driven by human population growth and food preferences. Higher demand for meat increases the beef cattle population and emissions. Non-cattle and dairy cattle emissions over the period remain about the same.

1.3.2 Future Emissions and Trends

As presented in Exhibit 6-4, methane emissions from livestock are projected to increase between 2000 and 2020, excluding possible Climate Change Action Plan (CCAP) reductions. In 2020, emissions from livestock are expected to reach 37.7 MMTCE (6.6 Tg), 36.2 MMTCE (6.3 Tg) from cattle and 1.5 MMTCE (0.3 Tg) from sheep, goats, pigs, and horses. The increase in emissions will be driven by beef cattle, due to the same factors that underlie the trends discussed above – increased human population and food preferences leading to higher beef consumption and more beef cattle. Exports of beef also are expected to increase.

Exhibit 6-3: Methane Emissions from Livestock (MMTCE)								
Animal Type	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**
Non-Cattle								
Sheep	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.3
Goats	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Pigs	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Horses	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Total Non-Cattle	**1.6**	**1.7**	**1.7**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**
Dairy Cattle								
Cows	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
Replacement Heifers 0-12 Months	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4
Replacement Heifers 12-24 Months	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.3
Total Dairy	**8.4**	**8.4**	**8.4**	**8.4**	**8.4**	**8.4**	**8.3**	**8.3**
Beef Cattle								
Cows	12.5	12.6	12.8	13.0	13.5	13.6	13.5	13.2
Replacements 0-12	0.7	0.7	0.7	0.8	0.8	0.8	0.7	0.7
Replacements 12-24	1.9	2.0	2.1	2.2	2.3	2.3	2.2	2.1
Slaughter-Weanlings	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8
Slaughter-Yearlings	5.6	5.6	5.6	5.6	5.9	6.1	6.0	6.2
Bulls	1.2	1.3	1.3	1.3	1.3	1.4	1.3	1.3
Total Beef	**22.6**	**22.8**	**23.1**	**23.6**	**24.5**	**24.9**	**24.6**	**24.3**
Total Cattle	**31.1**	**31.2**	**31.6**	**32.0**	**32.9**	**33.3**	**32.9**	**32.6**
Total Livestock	**32.7**	**32.8**	**33.2**	**33.6**	**34.5**	**34.9**	**34.5**	**34.1**
Totals may not sum due to independent rounding.								

Exhibit 6-4: Projected Baseline Methane Emissions from Livestock (MMTCE)					
Animal Type	**2000**	**2005**	**2010**	**2015**	**2020**
Sheep	0.3	0.3	0.3	0.3	0.3
Goats	0.1	0.1	0.1	0.1	0.3
Hogs	0.5	0.6	0.6	0.6	0.1
Horses	0.6	0.7	0.7	0.7	0.8
Total Non-Cattle	**1.5**	**1.7**	**1.7**	**1.8**	**1.5**
Dairy Cattle	8.5	8.8	8.8	8.9	8.9
Beef Cattle	25.1	25.4	26.1	26.7	27.3
Total Cattle	**33.7**	**34.1**	**34.9**	**35.6**	**36.2**
Total Livestock	**35.2**	**35.9**	**36.6**	**37.3**	**37.7**
Totals may not sum due to independent rounding.					

Future emissions will also be influenced by changes in animal management and feed practices. In the next section, some of these alternative management and feeding practices are described. Depending on how widespread these practices become, they will affect future levels of methane emissions.

1.4 Emission Estimate Uncertainty

The methane emission estimates used in this analysis are based on estimated animal and feed characteristics. Although the animal and feed characteristics used in the analysis represent the range of U.S. characteristics, they may not represent the full diversity in the U.S.

For sheep, goats, pigs, and horses, emission factor estimates are based on data from developed countries (U.S., Germany, and England), and not specifically from the U.S. Consequently, there is moderate uncertainty in how closely the emission factors represent typical animal sizes, feed intake, and feed characteristics in the U.S.

2.0 Emission Reductions

Unlike other methane emission sources for which there are technologies or practices aimed specifically at reducing emissions, no such control options are currently available for enteric fermentation. For this reason, EPA did not develop marginal abatement curves for emission reductions from enteric fermentation. Nevertheless, some aspects of livestock management can result in lower emissions, principally by improving dairy and beef production efficiency. This section describes techniques available or in-use that improve production efficiency. Additionally, this section provides forecasts of emissions under various assumptions, and describes how improved techniques will be implemented industry-wide.

2.1 Technologies for Reducing Methane Emissions

Implementing proper management techniques to improve animal nutrition and reproductive health is the primary means of improving production efficiency. Other reduction options, such as production enhancing agents, trade, and pricing systems are also used to increase production efficiency. Specific management techniques that improve animal production efficiency are discussed below.

Animal Nutrition and Health. The principal areas for improving animal productivity involve applying sound nutrition and veterinary practices. Feed that is better tailored to the metabolic requirements of the animal and that can be digested efficiently results in a greater proportion of the energy consumed going towards production, and less to waste and methane emissions. Some feeds, such as distiller grains, are high in protein and are highly digestible.

Combining proper nutritional management with proper veterinary care promotes growth and leads to higher levels of production than in the absence of such care. This care includes applying proper management techniques to maintain the comfort and health of the animals.

Grazing Management. Grazing cattle emit a significant portion of the methane from enteric fermentation. Consequently, implementing proper grazing management practices to improve the quality of pastures increases animal productivity and has a significant impact on reducing methane emissions from livestock enteric fermentation. By examining soil and plant composition and implementing steps to improve the health of the soil and ensuring the right mixture of plants, producers can enhance the nutrition and health of the cattle, and increase production.

Management intensive grazing is an effective form of grazing management. Unlike continuous grazing, in which cattle graze on large pastures for long periods of time and deplete the pasture of healthy plants, management intensive grazing is a form of grazing in which animals are rotated regularly among grazing units (paddocks) to maximize forage quality and quantity. This form of grazing management leads to vigorous plant growth, healthy soil, and a constant, nutritious source of food for the cattle. Overall, the health of the pasture is increased significantly. Production efficiency increases as a result, thereby reducing methane emissions per unit product and total methane emissions.

Artificial Insemination. An animal's genes have a significant influence on its productivity. Artificial insemination enables farmers to improve the genes of their herd by impregnating the animals with semen from healthy and productive bulls. In the U.S., artificial insemination is widely used by dairy operations. Artificial insemination is less popular in the beef industry with approximately seven percent of operations using the procedure in 1997 (USDA, 1998f). Given that genes affect animal productivity, artificial insemination is an excellent technique to improve the genes of an animal herd. An increase in the use of artificial insemination by beef operations could increase animal productivity and reduce methane emissions per unit product.

Production Enhancing Agents. With advances in science and biotechnology, a number of production enhancing agents are available that increase production efficiency in cattle. Production enhancing agents are meant to enhance the effect of proper animal health, nutrition, and grazing management practices. Three production enhancing agents are commonly available and are discussed below.

- **Bovine Somatotropin (Dairy Industry).** Bovine Somatotropin (bST), also known as bovine growth hormone (BGH), is a naturally occurring growth hormone in bovines produced by the pituitary gland. Recombinant bST (rbST), an essentially identical form of bST, is produced using modern biotechnology. The use of rbST with dairy cows can increase milk production per cow per year by 12 percent or by 1,800 lbs (EPA, 1996). After the U.S. Food and Drug Administration (FDA) approved the use of rbST, it was released on the market in 1994. Approximately 15 percent of the dairy cow population is treated with rbST (Monsanto, 1998). While there is still considerable public debate regarding the health risks of rbST, the FDA approved the use of rbST after performing a rigorous analysis of the potential health effects. Given that rbST is cost-effective and considered safe by the FDA, increased use of rbST is expected to take place in the future. If adopted widely by the dairy industry, the use of rbST could increase production efficiency and reduce methane emissions from dairy cattle by one to three percent, holding other factors constant (EPA, 1996).

- **Anabolic Agents (Beef Industry).** Anabolic steroids increase the rate of weight gain and feed intake in growing heifers and steers. The increased rate of weight gain reduces the time it takes for calves to reach slaughter weight. Steroid implants are considered cost-effective (USDA, 1987) and have been approved by the FDA. Steroids can reduce emissions by enhancing growth rates, feed efficiency, and lean tissue accretion (EPA, 1993b).

- **Ionophores (Beef Industry).** Ionophores are polyether antibiotics produced by soil microorganisms that gained attention in the 1970s for their ability to improve feed digestibility in cattle. They are administered to cattle by mixing them with feed or by providing them as a component of a multi-nutrient block, which is often a solid block of molasses supplemented with nutrients. Two types of ionophores, monensin and lasalocid, have been approved for use in the U.S. (EPA, 1993b).

Market Based Strategies. Practices that are focused on improving the health and nutrition of the animals are key to improving production efficiency. However, other strategies, such as trade and pricing systems, also have a substantial influence on production and management techniques.

- **Trade.** Changes in beef and dairy trade policy could result in higher U.S. emissions, but possibly lower emissions worldwide. Because U.S. dairy and beef operations are among the most efficient operations in the world, increasing U.S. exports could displace less efficient operations in other countries, and lower emissions. Although U.S. beef and dairy exports are currently low, they are expected to increase in the future as the U.S. beef industry seeks to gain greater access to foreign markets.

- **Dairy Prices.** Changes in the pricing systems for dairy products can reduce methane emissions. In the U.S., milk is uniformly graded and priced according to its butterfat content. This pricing system was useful when the demand for high-fat milk was stronger than it is today. With the demand for low-fat milk increasing, the dairy industry has begun changing from a single-component pricing system to a multiple-component pricing (MCP) system in which other components of milk, primarily protein, are reflected in the price.

  If this trend continues, producers will modify the feeding regimes of their dairy cows to include or increase the amount of high-protein feedstuffs, such as grain, which is also highly digestible. Increasing the proportion of high-protein feedstuffs will increase production. In addition, producers will breed cows that are genetically favored to produce low-fat, high-protein milk. These modifications would reduce methane emissions by increasing production efficiency.

- **Beef Prices**. Industry efforts are also underway to improve the quality of beef through Value-Based Marketing, an industry trend leading to more accurate pricing of beef based on value. One effect would be a reduction in incentives to produce excess fat in beef. Reducing fat in the animals would be achieved through genetic improvements and more efficient feeding practices. The result would also lead to lower methane emissions.

  This Value-Based Marketing trend may also provide incentives for a more efficient calf-slaughter system. Generally, calves go through one of two paths after they are weaned. Approximately 80 percent of calves pass through a stocker or backgrounding phase for several months, before entering the feedlot. The remaining 20 percent of calves go straight to the feedlot. Calves that are backgrounded are slaughtered at an older age and consequently emit more methane during their life cycle than calves that go straight to the feedlot. The Value-Based Marketing trend may cause an increase in the number of calves going directly to feedlots, with a consequent reduction in methane emissions (EPA, 1993a).

2.2 Achievable Emission Reductions

This section provides potential emission reductions under varying assumptions about how some of the practices and strategies described above are implemented. Potentially achievable emissions for dairy and beef cattle are presented in Exhibit 6-5 and Exhibit 6-7, respectively.

Dairy Cattle. Exhibit 6-5 provides future emission estimates from dairy cattle using scenarios in which rbST and MCP are adopted. USDA (1996) estimated milk production per cow and demand for dairy products through 2005. Demand after 2005 is expected to remain constant. In Exhibit 6-5, a constant baseline increase of 300 pounds of milk per cow per year is used to estimate future milk production. This increase is a current trend that is expected to continue as the dairy industry improves production efficiency. Future cow populations are estimated by using projected estimates of demand and milk production.

The emission factor estimates are multiplied by projected population estimates to estimate future emissions. The emission factor estimates for dairy cows change through time to account for changes in milk production levels.

Exhibit 6-5 shows the reduction in methane emissions when rbST and MCP are adopted. Improvements in animal and feed characteristics could potentially increase production efficiency and reduce emissions further.

Beef Cattle. EPA estimated methane emissions from beef cattle for three sets of emissions scenarios: (1) low; (2) medium; and (3) high emissions. The scenarios are presented in Exhibit 6-6, and the emissions estimates for each scenario are presented in Exhibit 6-7. For each of these sets, a baseline is defined by the level of domestic consumption and exports. Within

Exhibit 6-5: Projected Dairy Methane Emissions (MMTCE)

Scenario	2000	2005	2010	2015	2020
(1) Current emission factors	8.59	9.05	9.39	9.62	9.91
(2) Baseline increase of 300 lbs of milk/yr	8.53	8.82	8.82	8.88	8.93
(3) Low rbST Adoption – no MCP	8.48	8.71	8.76	8.82	8.88
(4) High rbST Adoption– no MCP	8.42	8.65	8.71	8.76	8.82
(5) No rbST Adoption- with MCP	8.25	8.48	8.48	8.53	8.59
(6) Low rbST Adoption - with MCP	8.19	8.42	8.42	8.48	8.53
(7) High rbST Adoption - with MCP	8.13	8.36	8.36	8.42	8.48

rbST = Recombinant Bovine Somatotropin; MCP = Multiple Component Pricing each set, EPA evaluated alternative scenarios that are defined in terms of improvements in the cow-calf phase and the growth-to-slaughter phase. These characteristics are described below.

- **Domestic Consumption**. As presented in Exhibit 6-6, future emissions are calculated under low, middle and high beef consumption scenarios, which combine different levels of domestic and export consumption. Consumption projections are the product of future per-capita consumption and population estimates. USDA (1996) published projected estimates of beef consumption through 2005.

- **Exports**. The U.S. cattle industry is highly efficient compared to the cattle industries of other countries. Consequently, increasing U.S. cattle exports would displace less efficient operations, and reduce methane emissions per unit product worldwide. Exhibit 6-6 summarizes the low, medium, and high export scenarios.

- **Cow-Calf Phase**. Improvements in management and nutrition are underway in the cow-calf sector, which accounts for a large portion of methane emitted by cattle in the U.S. Researchers and extension agents are working with producers to improve pasture management and implement better management techniques that improve animal health and nutrition. Because cow-calf operations in the southeastern U.S. are less efficient than cow-calf operations in other regions of the U.S., improving management practices in the southeast could have significant impacts on reducing methane emissions. Consequently, the cow-calf phase scenario in this analysis is for cow-calf operations in the southeastern U.S.

Implementing these measures improves production efficiency, which can be expressed in terms of calving rates and two-year-old heifer calving rates. The calving rate is the proportion of calves born from the total number of mature cows. The two-year-old heifer calving rate is the proportion of heifers in the population that successfully produce a calf by two years of age. Currently, the calving rate and two-year-old heifer calving rate for cow-calf operations in the southeast are approximately 70 and 50 percent, respectively. Improving these efficiencies would reduce the number of mother cows needed and, therefore, would reduce methane emissions. Exhibit 6-6 presents three cow-calf scenarios for low, medium, and high emissions.

Exhibit 6-6: Scenarios for Estimating Future Emissions from Beef Cattle

Scenario	Domestic Consumption Scenario	Export Scenario	Cow-Calf Phase Scenario [a-c]	Growth-to-Slaughter Phase Scenario [d]
Low Emissions	Continues to decline at the rate projected for 2000 to 2005	Increase by 25 million pounds per year by 2020	By 2010, the calving rate and two year old heifer calving rate increase to 85 and 75 percent, respectively	By 2010, 20/80 percent weanling/yearling changes to 80/20 percent
Medium Emissions	Average of low and high demand scenarios	Average of low and high scenarios	By 2015, the calving rate and two year old heifer calving rate increase to 85 and 75 percent, respectively	By 2010, 20/80 percent weanling/yearling changes to 50/50 percent
High Emissions	Remains at the 2005 consumption level	By 2015, equal to ten percent of total consumption	By 2020, the calving rate and two year old heifer calving rate increase to 85 and 75 percent, respectively	By 2010, 20/80 percent weanling/yearling changes to 30/70 percent

[a] For the baselines, the calving rate and two year old heifer calving rate are 70 and 50 percent, respectively.

[b] The calving rate is the proportion of calves born to the total number of cows in the population (expressed as a percentage).

[c] The two year old heifer calving rate is the proportion of heifers calving at two years of age to the total number of heifers that are two years of age or older in the population (expressed as a percentage).

[d] For the baselines, the growth-to-slaughter phase is 20 percent weanling/80 percent yearling.

- **Growth-to-Slaughter Phase**. Efforts are also underway to improve productivity in the growth-to-slaughter phase by increasing the proportion of calves that go directly from weaning to feedlots. Currently, approximately 20 percent of the calves go straight to feedlots, while 80 percent are held in a stocker phase for backgrounding. For this analysis, calves that go straight to feedlots are called weanlings, while calves that go through extended backgrounding are called yearlings. Increasing the percentage of weanlings would reduce the age at slaughter and would reduce methane emissions. In addition to increasing the proportion of calves that are weanlings, improved health and nutrition also increases production efficiency in the growth-to-slaughter phase. EPA created three scenarios to estimate projected emissions in growth-to-slaughter (see Exhibit 6-6).

Exhibit 6-7 presents the methane emissions for each scenario.

2.3 Reduction Estimate Uncertainties and Limitations

Considerable uncertatinty is associated with the scenarios shown in Exhibit 6-7. The major source of uncertainty are the forecasts of emission factors which depend on the extent to which the various strategies to improve production efficiency are implemented. In addition, there are major uncertainties in forecasts of demand for dairy and beef products that will influence the future animal population.

Exhibit 6-7: Methane Emissions from Beef Cattle (MMTCE)

Scenario	2000	2005	2010	2015	2020
Low Emissions Scenario					
Baseline - Low	25.1	25.4	25.4	25.4	25.2
Large Weanling/Yearling shift to 80%	24.4	23.9	23.0	23.0	22.9
Improved cow-calf by 2010	24.9	24.8	24.5	24.4	24.2
Both – Low	24.1	23.3	22.1	22.1	21.9
Middle Emissions Scenario					
Baseline – Medium[a]	25.1	25.4	26.1	26.7	27.3
Medium Weanling/Yearling shift to 50%	24.8	24.6	24.9	25.4	25.9
Improved cow-calf by 2015	24.9	25	25.3	25.7	26.2
Both – Medium	24.5	24.2	24.1	24.5	25.0
High Emissions Scenario					
Baseline – High	25.1	25.4	27.7	30.2	31.4
Small Weanling/Yearling shift to 30%	25.0	25.2	27.3	29.8	31.0
Improved cow-calf by 2020	25.0	25.1	27.1	29.4	30.3
Both – High	24.9	24.8	26.7	28.9	29.8

[a] EPA used this scenario to estimate future methane emissions from beef cattle as indicated in Exhibit 6-4.

3.0 References

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Appendix I: Supporting Material for Composite Marginal Abatement Curve

This appendix presents the data EPA used to develop the composite marginal abatement curve (MAC). The first section summarizes the incremental emissions reductions associated with each source, i.e., landfills, natural gas systems, coal mining, and livestock manure. The second section presents the approach to fit an equation to the MAC data.

I.1 Estimates for Composite Marginal Abatement Curve

This section presents estimates of the incremental emission reductions for each combination of carbon equivalent value and methane source. Exhibit I-1 presents these estimates. The exhibit also includes the cumulative emission reductions. These cumulative emission reductions form the composite MAC for 2010.

Exhibit I-1: Composite Marginal Abatement Curve Schedule of Options for 2010

Value of Carbon Equivalent $/TCE	Incremental Reductions (MMTCE)	Source	Cumulative Reductions (MMTCE)	Value of Carbon Equivalent $/TCE	Incremental Reductions (MMTCE)	Source	Cumulative Reductions (MMTCE)
($30.00)	0.29	Manure-Dairy	0.29	($16.32)	0.25	Coal	13.91
($30.00)	1.23	Manure-Swine	1.52	($16.00)	0.98	Natural Gas	14.89
($23.72)	0.45	Natural Gas	1.98	($15.74)	0.19	Natural Gas	15.08
($23.62)	0.23	Natural Gas	2.20	($15.67)	0.09	Natural Gas	15.17
($23.24)	0.64	Natural Gas	2.85	($15.11)	0.73	Natural Gas	15.89
($23.01)	0.12	Natural Gas	2.96	($14.45)	0.05	Natural Gas	15.95
($22.95)	0.24	Natural Gas	3.20	($14.41)	0.35	Natural Gas	16.30
($20.85)	0.32	Natural Gas	3.52	($14.14)	0.41	Coal	16.71
($20.00)	0.77	Manure-Dairy	4.29	($14.02)	0.14	Natural Gas	16.86
($19.86)	0.33	Natural Gas	4.62	($13.41)	0.29	Coal	17.15
($19.77)	0.42	Natural Gas	5.04	($12.17)	0.90	Natural Gas	18.04
($19.51)	0.87	Coal	5.91	($11.78)	0.31	Coal	18.35
($19.32)	1.63	Natural Gas	7.54	($11.50)	0.26	Coal	18.61
($19.18)	0.01	Natural Gas	7.55	($11.32)	0.41	Coal	19.02
($19.14)	0.79	Coal	8.34	($11.01)	0.20	Natural Gas	19.22
($19.13)	0.59	Natural Gas	8.93	($10.65)	0.04	Natural Gas	19.27
($18.96)	1.63	Coal	10.55	($10.59)	0.16	Coal	19.43
($18.87)	0.77	Coal	11.32	($10.50)	0.42	Coal	19.84
($18.69)	0.57	Coal	11.89	($10.39)	0.65	Natural Gas	20.49
($18.42)	0.48	Coal	12.37	($10.28)	0.02	Natural Gas	20.52
($16.86)	0.39	Natural Gas	12.76	($10.00)	0.62	Manure-Dairy	21.14
($16.70)	0.43	Natural Gas	13.20	($9.51)	0.04	Natural Gas	21.18
$16.41)	0.47	Coal	13.67	($9.23)	0.19	Coal	21.37

Exhibit I-1: Composite Marginal Abatement Curve Schedule of Options for 2010 (continued)

Value of Carbon Equivalent $/TCE	Incremental Reductions (MMTCE)	Source	Cumulative Reductions (MMTCE)	Value of Carbon Equivalent $/TCE	Incremental Reductions (MMTCE)	Source	Cumulative Reductions (MMTCE)
($9.16)	0.56	Natural Gas	21.93	$12.41	0.09	Coal	43.32
($7.87)	0.47	Coal	22.40	$12.78	0.11	Coal	43.43
($7.68)	0.38	Coal	22.78	$12.87	0.09	Coal	43.52
($7.50)	0.39	Natural Gas	23.17	$14.32	0.03	Coal	43.55
($6.92)	0.06	Natural Gas	23.24	$15.60	0.16	Coal	43.71
($6.77)	0.33	Coal	23.57	$16.23	0.07	Coal	43.78
($6.50)	0.09	Coal	23.66	$16.51	0.14	Coal	43.92
($6.23)	0.22	Coal	23.88	$16.78	0.11	Coal	44.03
($4.77)	0.34	Coal	24.21	$16.87	0.03	Coal	44.06
($3.80)	0.01	Natural Gas	24.22	$17.51	0.09	Coal	44.15
($3.23)	0.20	Coal	24.42	$18.42	0.06	Coal	44.21
($2.50)	0.14	Coal	24.56	$18.71	0.06	Natural Gas	44.27
($1.61)	0.01	Natural Gas	24.57	$18.84	0.35	Natural Gas	44.63
($1.41)	0.17	Coal	24.74	$18.84	0.22	Natural Gas	44.84
($1.32)	0.07	Coal	24.81	$19.06	0.14	Natural Gas	44.98
($0.86)	0.27	Coal	25.07	$19.69	0.06	Coal	45.04
($0.82)	0.60	Natural Gas	25.67	$20.00	0.20	Manure-Dairy	45.24
($0.59)	0.03	Coal	25.70	$20.00	1.54	Manure-Swine	46.78
($0.05)	0.10	Coal	25.80	$20.00	5.79	Landfills	52.57
$0.00	0.50	Manure-Dairy	26.30	$21.14	0.04	Coal	52.62
$0.00	10.55	Landfills	36.85	$21.51	0.02	Coal	52.63
$0.41	0.06	Coal	36.91	$22.87	0.07	Coal	52.70
$0.95	0.16	Coal	37.07	$23.96	0.05	Coal	52.75
$1.05	0.07	Coal	37.13	$24.51	0.03	Coal	52.77
$1.32	0.25	Coal	37.38	$24.65	0.00	Natural Gas	52.77
$2.05	0.15	Coal	37.53	$27.87	0.06	Coal	52.83
$3.51	0.15	Natural Gas	37.68	$29.70	6.28	Coal	59.10
$4.96	0.02	Coal	37.70	$30.00	0.18	Manure-Dairy	59.28
$5.23	0.24	Coal	37.94	$30.00	2.28	Manure-Swine	61.57
$5.25	0.02	Natural Gas	37.96	$30.00	1.22	Landfills	62.79
$6.45	0.14	Natural Gas	38.10	$31.59	0.51	Natural Gas	63.30
$6.58	0.04	Natural Gas	38.14	$35.52	0.77	Natural Gas	64.07
$6.60	0.10	Natural Gas	38.24	$35.52	0.00	Natural Gas	64.07
$7.19	0.03	Natural Gas	38.27	$38.14	0.87	Natural Gas	64.94
$7.62	0.21	Natural Gas	38.47	$38.60	0.42	Natural Gas	65.36
$9.32	0.18	Coal	38.65	$39.77	0.00	Natural Gas	65.36
$9.59	0.03	Coal	38.68	$40.00	0.16	Manure-Dairy	65.52
$10.00	0.31	Manure-Dairy	39.00	$40.00	1.45	Manure-Swine	66.97
$10.00	0.12	Manure-Swine	39.11	$40.00	0.29	Landfills	67.26
$10.00	3.89	Landfills	43.01	$40.88	0.00	Natural Gas	67.26
$11.23	0.03	Coal	43.04	$45.21	0.94	Natural Gas	68.20
$11.41	0.04	Coal	43.08	$47.09	0.32	Natural Gas	68.52
$11.69	0.07	Coal	43.14	$47.54	0.02	Natural Gas	68.54
$12.04	0.00	Natural Gas	43.14	$50.00	0.16	Manure-Dairy	68.70
$12.14	0.09	Coal	43.23	$50.00	1.18	Manure-Swine	69.88

Exhibit I-1: Composite Marginal Abatement Curve Schedule of Options for 2010 (continued)

Value of Carbon Equivalent $/TCE	Incremental Reductions (MMTCE)	Source	Cumulative Reductions (MMTCE)
$50.00	0.11	Landfills	69.98
$52.10	0.67	Natural Gas	70.65
$56.12	0.56	Natural Gas	71.22
$65.77	0.00	Natural Gas	71.22
$75.00	0.42	Manure-Dairy	71.63
$75.00	2.77	Manure-Swine	74.40
$75.00	0.05	Landfills	74.45
$76.24	0.08	Natural Gas	74.53
$95.34	0.21	Natural Gas	74.74
$95.47	0.00	Natural Gas	74.74
$100.00	0.38	Manure-Dairy	75.12
$100.00	0.40	Manure-Swine	75.52
$100.00	0.02	Landfills	75.54
$113.08	0.12	Natural Gas	75.66
$116.47	0.45	Natural Gas	76.10
$125.00	0.30	Manure-Dairy	76.41
$125.00	0.08	Manure-Swine	76.49
$140.29	0.01	Natural Gas	76.50
$150.00	0.27	Manure-Dairy	76.77
$166.22	0.03	Natural Gas	76.80
$175.00	0.23	Manure-Dairy	77.03
$188.35	0.07	Natural Gas	77.10
$200.00	0.19	Manure-Dairy	77.29

I.2 Equation for Composite Marginal Abatement Curve

The relationship between the additional value of carbon equivalent ($/TCE) and the cumulative emission reductions, i.e., abated methane in MMTCE is shown in Exhibit II-2. The cumulative emission reductions increases relatively slowly as a function of the value of carbon equivalent. As the cumulative emission reductions reach about 75 MMTCE, the reduction plateau and cannot be further abated at higher $/TCE values. In order to represent the steepness of the curve at values close to 75 MMTCE, EPA determined a best-fit curve based on the data points. This equation is defined by:

$$y = \text{parameter}_1 * \exp[\text{parameter}_2 / (\max - x)] \quad \text{offset}$$

where:
y = additional value of carbon equivalent ($/TCE)
x = cumulative emission reductions (MMTCE)
parameter_1, parameter_2, offset, and max = determined parameters

All values of x, i.e., cumulative emission reductions, must be less than the value of max. This curve has the property that as the x value increases to the value of max, the y value will tend to infinity, so the curve will approximate the steep rise at the maximum x value.

EPA used the method of least squares to find the best fitting curve. This method estimates the parameters by minimizing the mean square error (MSE), i.e., the average squared difference between the actual and fitted values of y: MSE = $(\text{actual } y \quad \text{fitted } y)^2 / n$, where n is the number of pairs, i.e., 159 pairs of abated methane and additional value of carbon equivalent. The minimum MSE is 68.6. The fitted parameters are:

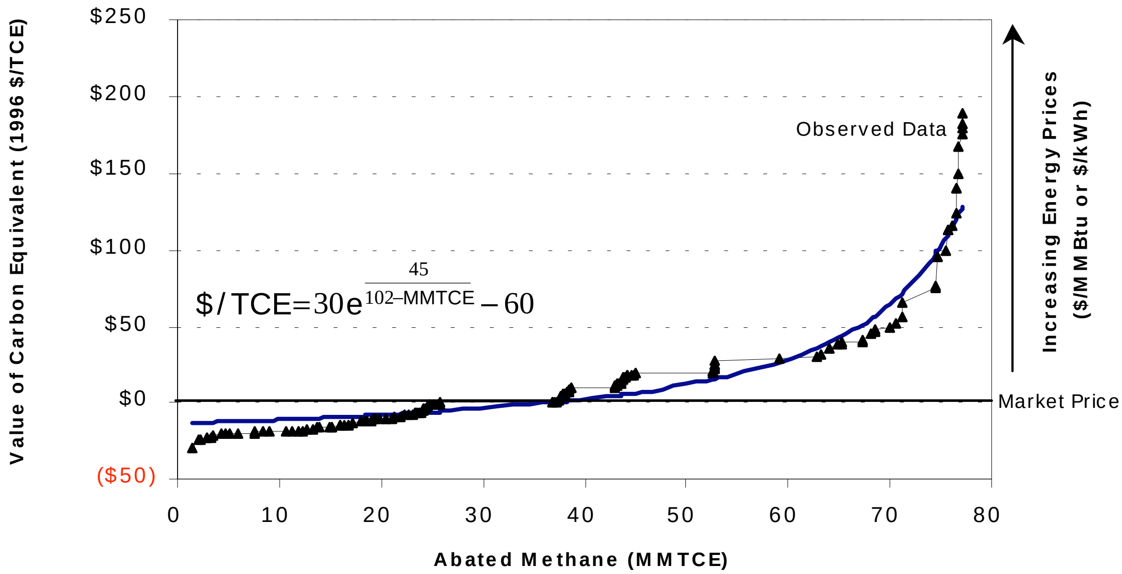
- offset = 60
- parameter_1 = 30
- parameter_2 = 45
- max = 102

The resulting equation is given by:

$$y = 30 * \exp [45/(102\text{-}x)] - 60$$

The squared correlation coefficient (R squared) between the actual and predicted values of *y* is 0.95, showing a reasonably good fit on a scale of zero to one, one being a perfect fit. Although the model was fitted using the method of least squares, the optimum least squares solution for this problem is also the solution with the maximum possible R squared. Exhibit II-2 presents the 159 data points and the fitted curve.

Exhibit II-2: Marginal Abatement Curve for U.S. Methane Emissions in 2010



Appendix II: Supporting Material for the Analysis of Landfills

In this appendix, EPA presents details on the methodologies to estimate the annual waste disposal rates and the costs for recovering methane from landfills. The appendix is comprised of six sections. The first section discusses the approach for projecting waste landfilled, and the second presents the assumptions used to evaluate costs and cost-effective emission reductions from landfill gas-to-energy projects (LFGTE). The third section describes the estimation method for the energy prices for which EPA conducts the analysis. The fourth section presents 84 break-even waste-in-place (WIP) and gas price combinations, a subset of which are used to construct a marginal abatement curve (MAC). The fifth section presents the cost-effective methane emission reductions for the energy prices and finally, the sixth section presents the uncertainties associated with the methods and analyses.

II.1 Waste Landfilled

This section provides an overview of the methods EPA uses to simulate waste in the population of U.S. landfills. EPA simulates waste disposal in U.S. landfills for the years 1990 through 2050. EPA bases the waste disposal data prior to 1990 on a 1988 landfill survey (EPA, 1988). For the years 1990 to 1997, EPA uses the BioCycle data presented in Exhibit II-1 (BioCycle, 1998). After 1997, waste disposal remains constant at 179,418 metric tons (MT). This estimate is the average of the BioCycle data from 1990 to 1995.

The analysis bases the total amount of waste disposed in each landfill on the design capacity and waste acceptance rate over time. Exhibit II-2 shows the design capacity for the categories of modeled landfills and Exhibit II-3 shows the percent of municipal solid waste (MSW) disposed in each landfill category from 1990 to 2050. Exhibit II-4 shows how EPA apportions total waste according to the waste disposal rates for each design capacity provided in Exhibit II-2.

Exhibit II-1: Landfill Waste Data

Year	Waste Generated[a] ('000 MT)	Percent Landfilled[b]	MSW Disposed in Landfills with Capacity < 500,000 MT[c]	Waste Landfilled for Categories 1-5[d]
1990	266,542	77%	10%	184,714
1991	254,797	76%	9%	175,443
1992	264,843	72%	9%	173,907
1993	278,573	71%	8%	181,568
1994	293,110	67%	8%	181,458
1995	296,586	63%	7%	173,770
1996	297,268	62%	7%	171,405
1997	309,075	61%	7%	175,338

[a, b] Source: BioCycle, 1998.

[c] These landfills are analyzed separately as they are excluded from EPA's 1988 landfill survey.

[d] The average between the beginning of 1990 to the beginning of 1995, is used to estimate total waste apportioned in each landfill category (see Exhibit II-4).

Exhibit II-2: Modeled Landfill Categories	
Landfill Category	**Capacity (MT)**
1 - Small	500,000
2 - Small-Medium	1,000,000
3 - Medium	5,000,000
4 - Large	15,000,000
5 - Very Large	> 15,000,000

Exhibit II-3: MSW Landfill Waste Disposal Rates (Percent of Total MSW Landfill Disposed)

Category	Base ('90)	1990-95	1995-00	2000-05	2005-10	2010-15	2015-20	2020-25	2025-50
1	3.0%	2.0%	2.0%	1.5%	1.0%	1.0%	0.5%	0.5%	0.5%
2	9.6%	9.0%	8.0%	7.0%	6.0%	5.0%	4.0%	3.0%	2.0%
3	39.4%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
4	27.0%	29.0%	30.0%	30.5%	31.0%	31.5%	32.0%	32.0%	32.0%
5	21.0%	20.0%	20.0%	21.0%	22.0%	22.5%	23.5%	24.5%	25.5%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Exhibit II-4: Total Waste Apportioned by Landfill Category (MT)

Category	Base('90)	1990-95	1995-00	2000-05	2005-10	2010-15	2015-20	2020-25	2025-50
1	5,541	3,588	3,588	2,691	1,794	1,794	897	897	897
2	17,732	16,148	14,353	12,559	10,765	8,971	7,177	5,383	3,588
3	72,777	71,767	71,767	71,767	71,767	71,767	71,767	71,767	71,767
4	49,873	52,031	53,825	54,722	55,620	56,517	57,414	57,414	57,414
5	38,790	35,884	35,884	37,678	39,472	40,369	42,163	43,957	45,752
Total:	**184,714**[a]	**179,418**[b]	**179,418**	**179,418**	**179,418**	**179,418**	**179,418**	**179,418**	**179,418**

[a, b] Source: BioCycle, 1998.

[b] 1995-2050 estimates are based on the average of the beginning of 1990 to the beginning of 1995.

II.2 Costs For Implementing Electricity And Direct Gas Use Projects

EPA uses different methods to estimate capital and operating and maintenance (O&M) costs for electricity generation and direct gas use. Exhibit II-5 presents the equations and assumptions used to calculate the total costs for electricity generation and Exhibit II-6 presents those used for direct gas use projects.

Exhibit II-5: Landfill Gas-to-Energy Project Cost Factors For Electricity Generation Projects

Cost Component	Cost Factors or Equation	Comments
Collection System Capital Cost	$[WIP (10^6 MT)]^{0.8} \times \$468,450$	The maximum amount of waste-in-place (WIP) during the project lifetime is used to estimate the capital cost.
Collection System O&M Annual Costs	0.04 x Capital Cost + $49,019	
Flare System Capital Costs	(Max Gas (ft^3/min) x $31) + $64,828	Max Gas is the peak gas flow rate during the anticipated operating lifetime from the collection system in cubic feet per minute.
Flare System O&M Costs	1.697 x Max Gas (ft^3/min) + $3,497	

Exhibit II-5: (continued)		
Cost Component	**Cost Factors or Equation**	**Comments**
Electric System Capacity in Megawatts (MW)	Max Gas (ft^3/min) x 500 Btu/ft^3 -- 10,000 Btu/kWh x 1,000 kW/MW	Max Gas is the peak gas flow rate from the collection system in cubic feet per minute. The heat rate of the IC engine is 10,000 Btu/kWh. The landfill gas is 50% methane, with a Btu content of 500 Btu/ft^3.
Electric Generation System Capital Costs	Maximum of a) or b): a) $10^{0.903 \times \log(MW)}$ x 1,674,000 - Collection System Capital Costs; or b) 1,200,000 x MW	MW is the system capacity. Collection system costs are as estimated above from the landfill WIP. Option (a) developed from levelized costs and an 8% real discount rate over 20 years.
Electric Generation System O&M Costs	$0.015 kWh	

All estimates in 1996 dollars.
Sources: EPA, 1991a and 1991b.

Exhibit II-6: Unit Costs for Direct Use Projects

System	Capital		O&M	
	Component	**Cost**	**Component**	**Cost**
Collection	Wells	$80 / foot of depth	Collection System Variable O&M	$1,000 / acre[a]
	Wellheads	$750 / wellhead		
	Piping (main & branch)	$35 / foot		
	Blowers	$20 / ft^3 / min		
	Condensate Knockout	$8,000 / unit		
	Monitoring System	$1,000 / unit		
Flare	Flares	$75,000 / unit	Flare Fixed O&M	$2,000 / yr
Compression	Compressor System Capital	$1,350 / hp	Compressor System Variable O&M	Calculated[b]
Gas System	Scrubber	$15 / ft^3 / min	Gas Treatment Variable O&M	$2.50 / mill ft^3 / yr
	Dessicator	$10 / ft^3 / min	Gas Treatment Fixed O&M	$10,000 / yr
	Refrigeration	$60 / ft^3 / min		
	Filters	$3,220 / unit		
	Gas Treatment Installation	$15 / ft^3 / min		
Pipeline	Five-Mile Pipeline (12 inch diameter)	$35 / ft	Pipeline Variable O&M	2% of capital cost

[a] This number is calibrated in the Energy Project Landfill Gas Utilization Software (E-PLUS) so that the annual collection O&M cost for each landfill is consistent with the annual collection O&M cost for electricity projects, i.e., within five to ten percent.

[b] The fixed O&M used in this analysis is calculated using the following formula: compressor qty (hp) x 8,760 (hrs/yr) x 0.7457 (hp-hr to kWh) x $0.04 (price of electricity) + $12,000/unit/yr.

Source: E-PLUS, EPA, 1997.

II.3 Energy Prices

EPA translates a range of carbon equivalent values into energy prices to analyze how placing a value on reducing emissions affects the cost-effectiveness of emission reductions from electricity generation. The equivalent electricity prices ($/kilowatt-hour (kWh)) for each carbon equivalent value ($/ton of carbon equivalent (TCE)) are shown in Exhibit II-7. EPA calculates the electricity price at which landfill owners sell electricity by adding the equivalent electricity prices to the market price of $0.04/kWh. These prices are also shown in Exhibit II-7. EPA then evaluates each electricity price plus the additional value of carbon equivalent ($/TCE) to develop the MAC.

Exhibit II-7: Equivalent Electricity Prices for Carbon Equivalent Values												
	Carbon Equivalent Value ($/TCE)											
	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
$/kWh	$0.00	$0.01	$0.02	$0.03	$0.04	$0.05	$0.08	$0.11	$0.14	$0.16	$0.19	$0.22
Base Prices	$0.04	$0.05	$0.06	$0.07	$0.08	$0.09	$0.12	$0.15	$0.18	$0.20	$0.23	$0.26

EPA uses a similar approach to calculate gas prices. A carbon equivalent value in $/TCE is converted into $/million British thermal units (MMBtu). The equivalent gas prices for each carbon equivalent value are shown in Exhibit II-8. EPA calculates the price at which landfill owners sell their gas by adding each equivalent gas price to the market gas price of $2.74/MMBtu. EPA uses these gas prices plus the additional value of carbon equivalent, shown in Exhibit II-8, to construct the MAC.

Exhibit II-8: Equivalent Gas Prices for Carbon Equivalent Values												
	Carbon Equivalent Value ($/TCE)											
	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
$/MMBtu	$0.00	$1.10	$2.20	$3.30	$4.40	$5.50	$8.25	$11.00	$13.75	$16.49	$19.24	$21.99
Base Prices	$2.74	$3.84	$4.94	$6.03	$7.13	$8.23	$10.98	$13.73	$16.48	$19.23	$21.98	$24.73

II.4 Break-Even Waste-in-Place

In order to determine if direct gas use projects are cost-effective, EPA conducts a benefit-cost analysis and estimates the break-even WIP for 84 gas prices. Each WIP and gas price combination is presented in Exhibit II-9. A subset of these values is used to create the MAC presented in the Landfill Chapter (see Exhibit 2-11). These 84 gas prices reflect a range in energy values from 50 to 300 percent of base energy prices shown in Exhibit II-8.

Exhibit II-9: Gas Price and Equivalent Break-Even WIP

Gas Price ($/MMBtu)	Break-Even WIP (MT)	Gas Price ($/MMBtu)	Break-Even WIP (MT)	Gas Price ($/MMBtu)	Break-Even WIP (MT)
$1.37	10,733,415	$7.82	419,389	$16.47	183,036
$2.05	2,330,467	$8.21	394,982	$16.48	182,893
$2.47	985,447	$8.23	393,655	$17.17	175,391
$2.74	972,739	$8.50	380,051	$17.85	167,889
$3.15	953,057	$8.77	366,448	$17.86	167,746
$3.42	940,349	$8.92	358,983	$18.55	160,244
$3.57	933,376	$9.31	341,640	$19.20	153,030
$3.84	920,668	$9.60	330,039	$19.22	152,886
$4.10	907,960	$9.62	329,523	$19.23	152,742
$4.25	900,986	$9.87	319,468	$19.91	147,367
$4.52	837,428	$10.30	302,581	$20.60	143,216
$4.67	800,200	$10.41	298,865	$20.61	143,137
$4.94	749,467	$10.97	283,826	$21.30	138,986
$5.20	698,987	$10.98	283,477	$21.95	134,995
$5.35	675,817	$11.51	269,487	$21.97	134,915
$5.47	656,765	$11.67	265,202	$21.98	134,836
$5.62	633,595	$12.35	247,859	$22.66	130,685

Exhibit II-9: (continued)					
Gas Price ($/MMBtu)	Break-Even WIP (MT)	Gas Price ($/MMBtu)	Break-Even WIP (MT)	Gas Price ($/MMBtu)	Break-Even WIP (MT)
$5.77	610,424	$12.36	247,615	$23.35	126,535
$6.03	576,422	$12.61	243,106	$23.36	126,456
$6.30	545,669	$13.05	234,879	$24.04	122,305
$6.45	530,436	$13.71	222,631	$24.70	118,313
$6.57	517,911	$13.72	222,387	$24.72	118,234
$6.72	502,678	$13.73	222,143	$24.73	118,155
$6.87	490,135	$14.42	209,407	$25.41	114,004
$7.13	468,324	$15.10	198,039	$26.10	109,854
$7.40	447,136	$15.11	197,896	$27.45	101,632
$7.55	437,304	$15.80	190,394	$27.46	101,553
$7.67	429,221	$16.46	183,180	$30.20	95,459

II.5 Marginal Abatement Curve

EPA evaluates the cost-effectiveness of LFGTE systems for the combinations of electricity and gas prices. The amounts of abated methane for 2000, 2010, and 2020 are displayed in Exhibit II-10 and Exhibit II-11. Exhibit II-10 shows the abated methane in million metric tons of carbon equivalent (MMTCE) and Exhibit II-11 shows the abated methane as a percent of the baseline. In each exhibit, the abated methane is incremental to methane abated as a result of the Landfill Rule. EPA estimates the percent abated methane as the emission reductions divided by the baseline emissions for the individual years. The baseline emissions are the emissions that would occur after the Landfill Rule emission reductions are taken into account. Each percent of abated methane represents cost-effective emission reductions for the combination of gas and electricity prices plus the added value of carbon equivalent. The market price, with no added value of carbon equivalent, is represented by $0/TCE.

An example of how percent abated methane is estimated at a combination of energy prices plus an additional carbon equivalent value is as follows. At $20/TCE in 2010, the emission reduction incremental to the Landfill Rule is 20.2 MMTCE and the electricity and gas prices are $0.06/kWh ($0.04/kWh + $0.02/kWh) and $4.94/MMBtu ($2.74/MMBtu + $2.20/MMBtu), respectively. The percent of abated methane at this combination of energy prices is 39%. This value is calculated as indicated in Exhibit II-12.

Exhibit II-10: Emission Reductions Incremental to the Landfill Rule by Year (MMTCE)

	Carbon Equivalent Value ($/TCE)											
	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
2000	11.03	14.08	18.21	19.74	20.13	20.55	21.23	21.41	21.49	21.56	21.61	21.66
2010	10.55	14.44	20.23	21.45	21.75	21.85	21.90	21.91	21.91	21.91	21.91	21.91
2020	7.62	10.12	13.88	15.00	15.46	15.69	15.84	15.88	15.88	15.90	15.90	15.92

Exhibit II-11: Emission Reductions Incremental to Landfill Rule by Year (Percent of Baseline Emissions)

	Carbon Equivalent Value ($/TCE)											
	$0	$10	$20	$30	$40	$50	$75	$100	$125	$150	$175	$200
2000	21%	27%	35%	38%	39%	40%	41%	42%	42%	42%	42%	42%
2010	20%	28%	39%	41%	42%	42%	42%	42%	42%	42%	42%	42%
2020	19%	25%	34%	37%	38%	38%	39%	39%	39%	39%	39%	39%

Exhibit II-12: Percent Reduction – Example Calculation	
Total Emissions from Landfills in 2010[a]	52.0 MMTCE (see Exhibit 2-6 in Chapter 2)
Landfill Rule Reductions in 2010	31.8 MMTCE (see Exhibit 2-6 in Chapter 2)
Total reductions incremental to the Landfill Rule in 2010 at $20/TCE	20.2 MMTCE (See Exhibit II-10)
Percent reduction in 2010 at $20/TCE	(20.2 / 52.0) MMTCE = 39 %

[a] This value accounts for reductions associated with landfills that are impacted by the Landfill Rule.

The methane abatement potential for non-Rule landfills in 2020 is slightly less than in the previous years because the Landfill Rule plays an increasingly large role in reducing emissions in the future. New landfills simulated to open are estimated to be larger (on average) than existing landfills. These larger landfills are expected to trigger under the Landfill Rule and, consequently, emissions decline in the future.

The collection efficiency for all landfill methane recovery projects, whether required by the Landfill Rule or not, is 75 percent. However, the percent of abated methane, even at high carbon equivalent values, is lower than 75 percent (see Exhibit II-11) due to EPA's methodology for estimating the percent of abated methane beyond regulation requirements. As indicated in Exhibit II-11, even at high additional carbon equivalent values, further abatement is not achieved as methane emissions cannot be collected with 100 percent efficiency. The example in Exhibit II-13 illustrates this concept.

The analysis evaluates the percent of abated methane from non-impacted landfills against baseline emissions. Baseline emissions represent a conglomerate of four sources: (1) methane from landfills not impacted by the Landfill Rule; (2) residual methane not recovered from landfills that are impacted by the Landfill Rule, i.e., methane that is emitted due to 75 percent collection efficiency and not captured by the gas collection system; (3) methane from industrial landfills; and (4) methane from small landfills. Consequently, the baseline emission value includes emissions from landfills impacted by the Landfill Rule that cannot further reduce emissions.[1]

Exhibit II-13: Calculating Percent Reductions - Hypothetical Example

- Emissions from landfills not impacted by the Landfill Rule:
  - Base emissions = 10.0 MMTCE
  - After installing LFGTE system = 2.5 MMTCE
  - Emissions reduced = 7.5 MMTCE
- Emissions from landfills impacted by the Landfill Rule:
  - Prior to installing LFGTE system = 20.0 MMTCE
  - Base emissions (after installing LFGTE system) = 5.0 MMTCE
- Base:
  - Emissions from landfills not impacted by the Landfill Rule plus resulting emissions from landfills impacted by Landfill Rule = (10.0 + 5.0 = 15.0) MMTCE
- Percent emissions reduced due to implementing cost-effective LFGTE:
  - Emissions reduced from landfills not impacted by rule divided by base = (7.5/15.0) MMTCE = 50 %

II.6 Uncertainties

Exhibit II-14 outlines the uncertainties with the methane estimation approach and Exhibit II-15 describes the uncertainties with the MAC.

[1] As the share of landfills impacted by the Rule increases over time, fewer emission reductions are achieved beyond the Landfill Rule requirements, i.e., the percent reduction approaches zero.

Exhibit II-14: Emission Estimate Uncertainties	
	Basis
Characterization of landfills and total WIP	A simulation characterizes the entire U.S. landfill population based on characterizations of a subset of U.S. landfills, including size, waste acceptance rate, and opening year.
Future waste disposal	Future waste disposal is assumed to remain constant at the average rate from the beginning of 1990 to the beginning of 1995. This average is based on the assumption that waste generation increases along with population, but will subsequently be offset by increases in alternative disposal methods such as recycling and composting.
Gas equation used for estimating methane emissions	Emission factors are derived from data on 85 U.S. landfills and are applied based on landfill WIP.
Recovery prior to 1997	Recovery rates (after flared methane is accounted for) are assumed to remain constant at 1990 levels for 1991 and at 1992 levels for 1993 to 1997. In addition, the gas collected but not utilized is assumed to equal 25 percent of the methane recovery.
Flare-only option	For years following 1997, the analysis lacks sufficient information about the population of landfills that flare without recovering methane for energy use.
Industrial waste landfilled	Industrial methane production is assumed to equal approximately seven percent of MSW landfill methane production.
Methane oxidation rate	Ten percent of methane generated is assumed to oxidize in soil.

Exhibit II-15: Cost Analysis Uncertainties	
	Basis
Cost estimate	Costs are estimated using aggregate cost factors and a relatively simple set of landfill characteristics. Electricity costs are estimated using representative WIP. Direct use costs are estimated using hypothetical landfills in terms of depth, area, and WIP.
Revenue	The rate at which electricity is sold from a landfill project depends on local and regional electric power market conditions and often varies by time of day and season of year. However, this analysis uses a representative figure that remains constant.
Potential for landfills to collect and use gas cost-effectively	The extent to which electricity production and direct gas use are cost-effective depends on the energy price and availability of end-users.
Methane recovery technologies	This analysis only focuses on internal combustion (IC) generators and direct gas use because they are the most cost-effective technologies for projects examined in this analysis. However, other technologies are available, e.g., electricity generation using turbine generators.
Equipment and engineering costs	Information is based on current projects and industry experts.

II.7 References

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Appendix III: Supporting Material for the Analysis of Natural Gas Systems

This appendix presents the detailed data that EPA used to develop methane emission forecasts and to estimate emission reduction costs. Exhibits III-1 and III-2 describe the emission factors, activity factors, and the activity factor drivers used to estimate annual changes in emissions and for forecasting future emissions. Exhibits III-3 and III-4 describe the specific options available for reducing emissions from gas systems. A summary of the costs of the specific options is summarized in Exhibits III-5 and III-6. Finally, Exhibit III-7 presents the data used to generate the marginal abatement curve for natural gas systems. The exhibits are summarized below.

- **Exhibit III-1: Activity Factors and Emission Factors.** This exhibit summarizes the activity and emission factors and the resulting emissions by source for 1992, which is the year covered by the EPA/GRI 1996 report, and the year on which emission estimates for all other years are based (EPA/GRI, 1996). For this analysis, the natural gas industry is divided into sectors: production, gas processing, transmission, and distribution. Within each sector, emissions are categorized as fugitives (leaks) and vented and combusted. Each line represents an emission source in the industry and sector. The emissions, expressed in tons of methane, are the product of the activity factor and the annualized emission factor, which is expressed in cubic feet of methane (standard cubic feet per day (scfd); thousand standard cubic feet per year (Mscfy)).
- **Exhibit III-2: Driver Variables.** The activity drivers and sources for the driver estimates are listed in this exhibit. Activity drivers are used to estimate emissions based on changes in characteristics of the natural gas industry. These characteristics include gas production, gas consumption, customers, miles of pipeline, number of wells, distribution infrastructure and other variables. The sources of data are primarily from publications produced by the Energy Information Administration, the American Petroleum Institute, and the Independent Petroleum Association of America.
- **Exhibit III-3: Best Management Practices.** This exhibit presents the Best Management Practices (BMPs) that EPA used to develop the cost curves for reducing methane emissions from the natural gas industry. The BMPs were identified by the Natural Gas STAR Program, a voluntary industry-EPA partnership created to identify cost-effective technologies and practices to reduce methane emissions.
- **Exhibit III-4: Partner-Reported Opportunities.** This exhibit presents the Partner-Reported Opportunities (PROs) that EPA used to develop the cost curves for reducing methane emissions from the natural gas industry. The PROs were identified by the Natural Gas STAR industry Partners as part of their efforts to reduce methane emissions cost-effectively.
- **Exhibit III-5: Cost Analysis Data and Assumptions for Best Management Practices.** This exhibit describes the BMPs in terms of their applicability to the natural gas industry, potential emission reductions once applied, capital and operation and maintenance costs, and break-even gas price.
- **Exhibit III-6: Cost Analysis Data and Assumptions for Partner-Reported Opportunities.** This exhibit describes the PROs in terms of their applicability to the natural gas industry, potential

emission reductions once applied, capital and operation and maintenance costs, and break-even gas price.

- **Exhibit III-7: Schedule of Emission Reduction Options for 2010.** The 118 emission reduction options used to generate the marginal abatement curve (MAC) for reducing methane emissions from U.S. natural gas systems are provided in this exhibit. All options are described in terms of their break-even gas price, base gas price type, value of carbon equivalent required in addition to the base gas price to make the option cost-effective, and incremental emission reduction.

Exhibit III-1: Activity Factors and Emission Factors[a]					
Segment	Activity Factor	Units	Emission Factor	Units	Emissions (Tons of Methane)
PRODUCTION					**1,476,877**
Normal Fugitives					
Gas Wells (Eastern on shore)					
Appalachia (all non-associated)	123,585 [b]	wells	7.11	scfd/well	6,157.85
N. Central					
Associated Gas Wells	3,507 [b]	wells	-	scfd/well	-
Non-Associated Gas Wells	4,977 [b]	wells	7.11	scfd/well	247.99
Field Sep. Equip. (Eastern on shore)					
Heaters	260	heaters	14.21	scfd/heater	25.89
Separators					
Appalachia	79,377	separators	0.90	scfd/sep	500.64
N. Central	12,293	separators	0.90	scfd/sep	77.54
Gathering Compressors					
Small Reciprocating Compressor					
Appalachia	4,943	compressors	12.10	scfd/comp	419.18
N. Central					
Associated Gas	270 [b]	compressors	12.10	scfd/comp	22.93
Non-Associated Gas	324 [b]	compressors	12.10	scfd/comp	27.48
Meters/Piping	11,693	meters	9.01	scfd/meter	738.30
Dehydrators	674	dehydrators	21.75	scfd/dehy	102.73
Gas Wells (Rest of U.S. on shore)	142,771 [b]	wells	36.40	scfd/well	36,419.53
Associated Gas Wells Rest of U.S.	256,226 [b]	wells	-	scfd/well	-
Gulf of Mexico Off-Shore Platforms	1,350 [b]	platforms	2,914.00	scfd/plat	27,568.77
Rest of U.S. (Off-Shore platforms)	22 [b]	platforms	1,178.00	scfd/plat	181.62
Field Separation Equipment - Rest of U.S. On Shore					
Heaters	50,740	heaters	57.70	scfd/heater	20,517.14
Separators	74,670	separators	122.00	scfd/sep	63,841.09
Gathering Compressors					
Small Reciprocating Compressor	16,915 [b]	compressors	267.80	scfd/comp	31,745.18
Large Reciprocating Compressor	96	compressors	15,205.00	scfd/comp	10,229.44
Large Reciprocating Compressor	12	stations	8,247.00	scfd/station	693.54
Meters/Piping	177,438	meters	52.90	scfd/meter	65,780.56
Dehydrators	24,289	dehydrators	91.10	scfd/dehy	15,506.55
Pipeline Leaks	340,200	miles	53.20	scfd/mile	126,835.09
Vented and Combusted					
Drilling and Well Completion					
Completion Flaring	400 [b]	compl/yr	733.00	scf/comp	5.63
Normal Operations					
Pneumatic Device Vents	249,111 [b]	controllers	345.00	scfd/device	602,291.32
Chemical Injection Pumps	16,971	active pumps	248.05	scfd/pump	29,501.85
Kimray Pumps	7,380,194	MMscf/yr	992.00	scf/MMscf	140,566.12
Dehydrator Vents	8,200,215	MMscf/yr	275.57	scf/MMscf	43,386.88
Compressor Exhaust Vented					
Gas Engines	27,460 [b]	MMHPhr	0.24	scf/HPhr	126,535.33
Routine Maintenance					
Well Workovers					
Gas Wells	9,392	w.o./yr	2,454.00	scfy/w.o.	442.52
Well Clean Ups (LP Gas Wells)	114,139	LP gas wells	49,570.00	scfy/LP well	108,630.91
Blowdowns					
Vessel BD	242,302	vessels	78.00	scfy/vessel	362.87
Pipeline BD	340,200	miles (gath)	309.00	scfy/mile	2,018.34
Compressor BD	17,112	compressors	3,774.00	scfy/comp	1,239.95
Compressor Starts	17,112	compressors	8,443.00	scfy/comp	2,773.96
Upsets					
Pressure Relief Valves	529,440 [b]	PRV	34.00	scfy/PRV	345.62

Exhibit III-1: Activity Factors and Emission Factors[a] (continued)					
Segment	Activity Factor	Units	Emission Factor	Units	Emissions (Tons of Methane)
PRODUCTION (continued)					
Vented and Combusted (continued)					
ESD	1,372	platforms	256,888.00	scfy/plat	6,767.05
Mishaps	340,200	miles	669.00	scfy/mile	4,369.79
GAS PROCESSING PLANTS					**697,555**
Normal Fugitives					
Plants	726 [b]	plants	7,906.00	scfd/plant	40,224.08
Recip. Compressors	4,092 [b]	compressors	11,196.00	scfd/comp	321,066.39
Centrifugal Compressors	726 [b]	compressors	21,230.00	scfd/comp	108,014.07
Vented and Combusted					
Normal Operations					
Compressor Exhaust					
Gas Engines	27,460 [b]	MMHPhr	0.24	scf/HPhr	126,535.45
Gas Turbines	32,910 [b]	MMHPhr	0.01	scf/HPhr	3,601.67
AGR Vents	371	AGR units	6,083.00	scfd/AGR	15,814.96
Kimray Pumps	957,930	MMscf/yr	177.75	scf/MMscf	3,269.22
Dehydrator Vents	8,630,003 [b]	MMscf/yr	121.55	scf/MMscf	20,140.36
Pneumatic Devices	726	gas plants	164,721.00	scfy/plant	2,296.07
Routine Maintenance					
Blow downs/Venting	726	gas plants	4,060.00	Mscfy/plant	56,592.96
Fugitives					
Pipeline Leaks	284,500 [b]	miles	1.54	scfd/mile	3,072.41
Compressor Stations (Trans.)					
Station	1,700	stations	8,778.00	scfd/station	104,605.04
Recip Compressor	6,799	compressors	15,205.00	scfd/comp	724,478.87
Centrifugal Compressor	681	compressors	30,305.00	scfd/comp	144,629.14
Compressor Stations (Storage)					
Station	386 [b]	stations	21,507.00	scfd/station	58,178.33
Recip Compressor	1,135	compressors	21,116.00	scfd/comp	167,958.35
Centrifugal Compressor	111	compressors	30,573.00	scfd/comp	23,782.37
Wells (Storage)	17,999	wells	114.50	scfd/well	14,442.69
M&R (Trans. Co. Interconnect)	2,532	stations	3,984.00	scfd/station	70,694.51
M&R (Farm Taps + Direct Sales)	72,630	stations	31.20	scfd/station	15,880.59
Vented and Combusted					
Normal Operation					
Dehydrator Vents (Transmission)	1,086,001	MMscf/yr	93.72	scf/MMscf	1,954.18
Dehydrator Vents (Storage)	2,000,001 [b]	MMscf/yr	117.18	scf/MMscf	4,499.71
Compressor Exhaust					
Engines (Transmission)	40,380 [b]	MMHPhr	0.24	scf/HPhr	186,071.04
Turbines (Transmission)	9,635 [b]	MMHPhr	0.01	scf/HPhr	1,054.45
Engines (Storage)	4,922 [b]	MMHPhr	0.24	scf/HPhr	22,680.58
Turbines (Storage)	1,729 [b]	MMHPhr	0.01	scf/HPhr	189.22
Generators (Engines)	1,976 [b]	MMHPhr	0.24	scf/HPhr	9,105.42
Generators (Turbines)	23 [b]	MMHPhr	0.01	scf/HPhr	2.55
Pneumatic Devices Trans + Storage					
Pneumatic Devices Trans	68,103	devices	162,197.00	scfy/device	212,084.78
Pneumatic Devices Storage	15,460	devices	162,197.00	scfy/device	48,145.26
Routine Maintenance/Upsets					
Pipeline Venting	284,500	miles	31.65	Mscfy/mile	172,884.96
Station venting Trans + Storage					
Station Venting Transmission	1,700	cmp stations	4,359.00	Mscfy/station	142,315.12
Station Venting Storage	386	cmp stations	4,359.00	Mscfy/station	32,305.42

Exhibit III-1: Activity Factors and Emission Factors[a] (continued)

Segment	Activity Factor	Units	Emission Factor	Units	Emissions (Tons of Methane)
TRANSMISSION					**2,228,280**
LNG Storage					
LNG Stations	64 [b]	stations	21,507.00	scfd/station	9,646.15
LNG Reciprocating Compressors	246 [b]	compressors	21,116.00	scfd/comp	36,403.31
LNG Centrifugal Compressors	58 [b]	compressors	30,573.00	scfd/comp	12,426.82
LNG Compressor Exhaust					
LNG Engines	741 [b]	MMHPhr	0.24	scf/HPhr	3,414.53
LNG Turbines	162 [b]	MMHPhr	0.01	scf/HPhr	17.73
LNG Station Venting	64	cmp stations	4,359.00	Mscfy/station	5,356.34
DISTRIBUTION					**1,495,565**
Normal Fugitives					
Pipeline Leaks					
Mains - Cast Iron	55,288 [b]	miles	238.70	Mscf/mile-yr	253,387.12
Mains - Unprotected Steel	82,109 [b]	miles	110.19	Mscf/mile-yr	173,706.87
Mains - Protected Steel	444,768	miles	3.12	Mscf/mile-yr	26,623.73
Mains – Plastic	254,595	miles	19.30	Mscf/mile-yr	94,324.89
Total Pipeline Miles	836,760 [b]	.			
Services - Unprotected Steel	5,446,393 [b]	services	1.70	Mscf/service	177,815.33
Services Protected Steel	20,352,983 [b]	services	0.18	Mscf/service	69,000.53
Services – Plastic	17,681,238	services	0.01	Mscf/service	3,161.82
Services – Copper	233,246 [b]	services	0.25	Mscf/service	1,138.36
Total Services	43,713,860 [b]				
Meter/Regulator (City Gates)					
M&R >300 psi	3,580	stations	179.80	scfh/station	108,277.61
M&R 100-300 psi	13,799	stations	95.60	scfh/station	221,882.88
M&R <100 psi	7,375	stations	4.31	scfh/station	5,346.34
Reg >300 psi	4,134	stations	161.90	scfh/station	112,573.59
R-Vault >300 psi	2,428	stations	1.30	scfh/station	530.82
Reg 100-300 psi	12,700	stations	40.50	scfh/station	86,512.45
R-Vault 100-300 psi	5,706	stations	0.18	scfh/station	172.75
Reg 40-100 psi	37,593	stations	1.04	scfh/station	6,575.79
R-Vault 40-100 psi	33,337	stations	0.09	scfh/station	485.01
Reg <40 psi	15,913	stations	0.13	scfh/station	355.96
Customer Meters					
Residential	40,049,306 [b]	outdr meters	138.50	scfy/meter	106,499.11
Commercial/Industry	4,607,983 [b]	meters	47.90	scfy/meter	4,237.87
Vented					
Routine Maintenance					
Pressure Relief Valve Releases	836,760	mile main	0.05	Mscf/mile	803.29
Pipeline Blowdown	1,297,569 [b]	Miles	0.10	Mscfy/mile	2,541.16
Upsets					
Mishaps (Dig-ins)	1,297,569	miles	1.59	mscfy/mile	39,612.18
TOTAL					**5,898,278**

[a] Data are for base year 1992, the year covered by the EPA/GRI 1996 report, and the year from which emission estimates for all other years are based.
[b] Main driver for the emission inventory.
Source: EPA/GRI, 1996.

Exhibit III-2: Driver Variables		
Variable	**Units**	**Source**
Dry Gas Production: National Total	Tcf / yr	EIA (www.eia.doe.gov), *Natural Gas Monthly*, Table of Supply and Disposition of Dry Natural Gas in the United States, 1992-1997
Dry Gas Production: National Total minus Alaska	Tcf / yr	Calculated, based on an estimate of gas production in Alaska
Gas Production: Alaska	Tcf / yr	Estimate, based on EIA data (www.eia.doe.gov), *Natural Gas Monthly*, Table of Marketed Production of Natural Gas By State
Gas Consumption: National Total	Tcf / yr	EIA (www.eia.doe.gov), *Natural Gas Monthly*, Table of Natural Gas Consumption in the United States, 1992-1997
Gas Consumption: Residential	Tcf / yr	EIA (www.eia.doe.gov), *Natural Gas Monthly*, Table of Natural Gas Consumption in the United States, 1992-199
Gas Consumption: Commercial	Tcf / yr	EIA (www.eia.doe.gov), *Natural Gas Monthly*, Table of Natural Gas Consumption in the United States, 1992-1997
Gas Consumption: Industrial	Tcf / yr	EIA (www.eia.doe.gov), *Natural Gas Monthly*, Table of Natural Gas Consumption in the United States, 1992-1997
Gas Consumption: Electrical Generators	Tcf / yr	Estimate, based on EIA data (www.eia.doe.gov), *Natural Gas Monthly*, Table of Natural Gas Deliveries to Electric Utility Consumers
Gas Consumption: Lease and Plant Fuel	Tcf / yr	EIA (www.eia.doe.gov), *Natural Gas Monthly*, Table of Natural Gas Consumption in the United States, 1992-1997
Gas Consumption: Pipeline Fuel	Tcf / yr	EIA (www.eia.doe.gov), *Natural Gas Monthly*, Table of Natural Gas Consumption in the United States, 1992-1997
Gas Consumption: Transportation	Tcf / yr	NGA 1993 (1990-1992) & NGA97 (1993-two years before current year), Table 1 – Summary Statistics
Transmission Pipelines Length	Miles	American Gas Association, *Gas Facts*
Appalachia Wells	Wells	IPAA, *The Oil and Gas Producing Industry in Your State*
North Central Associated Wells	Wells	Calculated as 8.6% of oil wells reported in IPAA, *The Oil and Gas Producing Industry in Your State*
North Central Non-Associated Wells	Wells	IPAA, *The Oil and Gas Producing Industry in Your State*
Rest of U.S. Wells	Wells	IPAA, *The Oil and Gas Producing Industry in Your State*
Rest of U.S. Associated Wells	Wells	Calculated as 46.1% of oil wells reported in IPAA, *The Oil and Gas Producing Industry in Your State*
Appalachia, North Central (Non-Associated), and Rest of U.S.	Wells	Calculated using data for two years prior to 1997
Gulf of Mexico Off-Shore Platforms	Platforms	Minerals Management Service
Rest of U.S. Off-Shore Platforms	Platforms	May include platforms off the shore of Alaska, Minerals Management Service
North Central (Non-associated) and rest of U.S.	Wells	Calculated using data for two years prior to 1997
Number of Gas Plants	Plants	*Oil and Gas Journal*
Distribution Mains – Cast Iron	Mains	American Gas Association, *Gas Facts*
Distribution Mains – Unprotected Steel	Miles	American Gas Association, *Gas Facts*
Distribution Mains – Protected Steel	Miles	American Gas Association, *Gas Facts*
Distribution Mains – Plastic	Miles	American Gas Association, *Gas Facts*
Services – Unprotected Steel	Services	American Gas Association, *Gas Facts*
Services – Protected Steel	Services	American Gas Association, *Gas Facts*
Services – Plastic	Services	American Gas Association, *Gas Facts*
Services - Copper	Services	American Gas Association, *Gas Facts*

Exhibit III-3: Best Management Practices

Best Management Practice	Description
Replace or repair high bleed pneumatics devices with low bleed devices	High bleed rate pneumatic devices that employ gas to operate the actuators are ubiquitous in the industry and are a major source of emissions. Replacing them with low bleed devices where possible reduces emissions considerably.
Practice directed inspection and maintenance of compressor stations	Compressor stations have a vast number of pipes, valves, and other equipment that leaks. As with gate stations, a very few leaks account for the total volume of emissions. The same strategy applied to compressor stations will reduce the vast majority of emissions at a low cost.
Reduce glycol recirculation rates on glycol dehydrators	Glycol dehydrators remove water from gas at the wellhead. The glycol also absorbs methane, which is vented to the atmosphere when the glycol is regenerated, at a rate directly proportional to the glycol circulation rate. Glycol is often over-circulated. Proper circulation rates can achieve pipeline water content requirements and reduce methane emissions.
Install flash tanks on glycol dehydrators	Glycol dehydrators remove water from gas at the wellhead. The glycol also absorbs methane, which is vented to the atmosphere when the glycol is regenerated. Flash tanks capture 90 percent of the methane before it reaches the reboiler.
Install fuel gas retrofit systems on compressors to capture otherwise vented fuel when compressors are taken off-line	When compressors are not running and are taken "offline," they are often purged of the gas in the compression chambers and isolated from the high-pressure pipeline with much leakage occurring at the isolation valves. Keeping the isolated compressor pressurized and bleeding off the gas into a fuel gas system reduces losses to the atmosphere.
Install static-seal compressor rod packing on reciprocating compressors	Compressor rod packing keeps gas from the compressor from escaping along the shaft into the compressor housing. Packing leaks are greater while compressors are off-line and remain pressurized. Static-packs clamp down on the compressor rod when compressors are idle to reduce leakage.
Install dry seal systems on centrifugal compressors	Centrifugal compressors have elaborate sealing systems to keep high-pressure gas in the compressor from escaping. Wet seal systems use high-pressure oil as the seal. The oil absorbs gas and which is vented when the sealing oil is circulated. Dry seal systems use high pressure air to establish a seal and avoid these losses.
Practice early replacement of rings and rods on centrifugal compressors	By using company-specific financial objectives and monitoring data, natural gas transmission companies can determine emission levels at which it is cost effective to replace rings and rods.
Practice directed inspection and maintenance of gate stations and surface facilities	Gate Stations are where high transmission pipeline pressures are dropped down to distribution system pressures; other surface facilities also regulate pipeline pressures. Emissions occur at the equipment, joints, valves at these facilities. A few stations and equipment types account for most of the emissions. Directed inspection and maintenance uses leak rate data and economic criteria to focus repairs on the costliest leaks.

Exhibit III-4: Partner-Reported Opportunities

Partner-Reported Opportunities	Description
Practice directed inspection and maintenance of production sites, processing sites, transmission pipelines and liquid natural gas stations	Emissions occur at the equipment, joints, valves at these facilities. Directed inspection and maintenance uses leak rate data and economic criteria to focus repairs on the costliest leaks.
Practice enhanced directed inspection and maintenance at production sites, surface facilities, storage wells, off-shore platforms and compressor stations	Enhanced DI&M is a more aggressive DI&M program that involves increased frequency of survey and repair. Enhanced DI&M costs more but also achieves greater savings by further reducing gas leaks.
Install electric starters on compressors	Compressor engines are often started using a blast of high-pressure natural gas. Electric starters can replace these gas starters and avoid methane emissions.
Install plunger lifts at production wells	As gas fields mature, fluids can accumulate in the wellbore and the weight of these fluids can impede gas production. Accumulated fluids can be removed by swabbing, soaping, or "blowing down" the well, but these operations often emit large volumes of methane to the atmosphere. A plunger lift allows fluids to be removed without emitting methane. The plunger acts as a bottom-hole plug, and the pressure of the reservoir builds and slowly lifts the plunger to the surface. As the plunger is lifted, the reservoir fluid above it is also lifted. Plunger lifts prolong well life, increase productivity and reduce methane emissions.
Use capture vessels for blowdowns at processing plants and other facilities	A capture vessel can be used during blowdowns to avoid venting methane to the atmosphere. The captured natural gas can be re-routed to pipelines or used on-site as fuel.
Install instrument air systems	Methane leaks from pneumatic devices can be avoided by installing instrument air systems which open and close valves using electricity instead of pressure from gas systems.
Use portable evacuation compressors for pipeline repairs	A portable compressor can be used to evacuate the gas in an area of blocked-off pipeline that is about to be repaired. This gas can be re-routed to the pipeline.
Install catalytic converter on compressor engines	A catalytic converter is an afterburner that reduces pollution from incomplete fuel combustion. Methane is combusted, and the energy from combustion is unused, so benefits are restricted to the value placed on reducing methane emissions.
Use electronic metering	Replacing old pneumatic-based meter runs at gate stations with electronic meters will reduce methane emissions.
Replace cast iron distribution mains with protected steel or plastic pipe	Cast iron and unprotected steel pipeline is replaced with materials less prone to corrosion and leaks.
Replace cast iron distribution services with protected steel or plastic pipe	Cast iron services are replaced with materials less prone to corrosion and leaks.

Exhibit III-5: Cost Analysis Data and Assumptions for Best Management Practices

Best Management Practice	Applicability and Emission Reductions	Costs	Break-Even Gas Price ($/MMBtu)
Replace high-bleed pneumatics with low-bleed pneumatics	Applicability: 50%-90% of pneumatic systems in the production and transmission sector Emission Reduction: 50%-90%; for all sectors, applicability and emission reductions are higher for high-bleed devices For the production sector, 6 cases were examined (low-med.-high bleed; intermittent & continuous) For the transmission sector, 9 cases were examined (low-med.-high bleed; continuous, turbine & displacement)	Capital: $750/device ($1,500 per device x 0.5 to reflect early replacement) Annual O&M: $150	$0.49-$18.00 for the production sector; break-even gas prices are lower for high-bleed devices $0.20-$318 for the transmission sector; break-even gas prices are lower for high-bleed devices
Practice directed inspection and maintenance at compressor stations	Applicability: 100% of compressor stations in the transmission sector Emission Reduction: 12%	Capital: $5,000/station instrument spread across 10 facilities yielding $500/facility Annual O&M: $2,065/station	$0.55 for storage compressor stations $0.61 for transmission compressor stations
Use static-seal compressor rod packing	Applicability: 100% of reciprocating compressors in the transmission sector Emission Reduction: 6.0% of emissions from storage compressor stations, 8.7% of emissions from transmission compressor stations	Capital: $3,000/compressor Annual O&M: none	$1.81 for storage compressor stations $1.74 for transmission compressor stations
Reduce glycol recirculation rates on dehydrators	Applicability: 100% of dehydrators in production, processing and transmission sector Emission Reduction: 30-60% of emissions from production and processing, 30% of emissions from transmission For the production and processing sectors, 4 cases were examined (with/ & without flash tanks; with & without pumps)	Capital: $0 Annual O&M: $50/dehydrator	$0.45 for dehydrators without flash tanks in the processing sector $50.64-$101 for dehydrators with flash tanks in the processing sector $0.16 for dehydrators without flash tanks in transmission sector $0.68 for dehydrators with flash tanks in transmission sector
Install flash tank separators on glycol dehydrators	Applicability: 100% of glycol dehydrators without flash tanks in the production, processing and transmission sectors Emission Reduction: For the production and processing sectors, 12%-63% of emissions from dehydrator vents and 63% of emissions from Kimray pumps; for the transmission sector, 90% of emissions from dehydrators with gas-assisted pumps, 30% of emissions from dehydrators without gas-assisted pumps	Capital: $8,000/dehydrator Annual O&M: None	$9.49 for dehydrators with gas assisted pumps and $232 for dehydrators without gas assisted pumps on dehydrator vents in the production and processing sectors $3.42 for transmission sector
Use fuel gas retrofits	Applicability: 100% of reciprocating compressors in the transmission sector Emission Reduction: 36% of emissions from reciprocating compressors in the transmission sector, 21.3% of emissions from reciprocating compressors in gas processing plants	Capital: $1,250/compressor Annual O&M: None	$0.12 for storage compressor stations $0.17 for transmission compressor stations $0.40 for processing compressor stations

Exhibit III-5: Cost Analysis Data and Assumptions for Best Management Practices (continued)

Best Management Practice	Applicability and Emission Reductions	Costs	Break-Even Gas Price ($/MMBtu)
Change wet seals to dry seals on centrifugal compressors	Applicability: 100% of all centrifugal comp. in the processing and transmission sectors Emission Reduction: 77.2% of emissions from storage comp., 70.9% of emissions from trans. comp. stations, 65.9% of emissions from processing comp.	Capital: $240,000/compressor Annual O&M: savings in material and labor relative to wet seals of $63,000/compressor	$1.91 for storage compressor stations $2.10 for transmission compressor stations $3.22 for processing compressor stations
Practice early replacement of rings and rods on reciprocating compressors	Applicability: 100% of reciprocating compressors in the transmission sector Emission Reduction: 1.4% of emissions from storage compressor stations, 1.5% of emissions from trans. compressor stations	Capital: $100/compressor Annual O&M: $120	$2.09 for storage compressor stations $2.66 for transmission compressor stations
Practice directed inspection and maintenance at gate stations and surface facilities	Applicability: For transmission sector, 100% of transmission co. interconnect meter and regulator stations; for distribution sector, 100% of high pressure stations, 50% of medium pressure stations, and 0% of low pressure stations Emission Reduction: For transmission sector, 33% of emissions; for distribution sector, 33% of emissions from high pressure, 25% of emissions from medium pressure stations	Capital: $5,000/survey instrument spread across 20 facilities yielding $250/station Annual O&M: $295/station	For transmission sector: $0.75 for transmission co. interconnect $320 for farm taps and direct sales For distribution sector: $0.69 for M&R >300 psi $1.74 for M&R 100-300 psi $96.58 for M&R <100 psi

Exhibit III-6: Cost Analysis Data and Assumptions for Partner-Reported Opportunities

Partner Reported Opportunity	Applicability and Emission Reductions	Costs	Break-Even Gas Price ($/MMBtu)
Practice directed inspection and maintenance at production sites	Applicability: 100% of non-associated gas wells, 100% of off-shore platforms, and 100% of pipeline leaks in the production sector Emission Reduction: 33% of emissions from non-associated gas wells, 33% of emissions from off-shore platforms, and 60% of emissions from pipeline leaks	Capital: $200/well, $6,000/off-shore platform, $100/mile of pipeline Annual O&M: $300/well, $2,000/off-shore platform, $150/mile of pipeline	$415 for eastern on-shore non-associated gas wells $81.14 for rest of U.S. gas wells $10.46 for Gulf of Mexico off-shore platforms $25.88 for rest of U.S. off-shore platforms $15.27 for pipeline leaks $15.10 for chemical injection pumps
Use enhanced directed inspection and maintenance at production sites	Applicability: 100% of non-associated gas wells in the production sector Emission Reduction: 50%	Capital: $500 Annual O&M: $700	$647 for eastern on-shore non-associated gas wells $126 for rest of U.S. gas wells
Use electric starter	Applicability: 100% of compressor starts in the production sector Emission Reduction: 75%	Capital: $20,000/compressor Annual O&M: $5,000/compressor	$1,536
Use plunger lift well	Applicability: 20% of Appalachia (all non-associated) and 20% of rest of U.S. on-shore wells in the production sector Emission Reduction: 20%	Capital: $2,500/well Annual O&M: $100/well	$1,330 for Appalachia wells $260 for rest of U.S. on-shore wells
Use surge vessel to capture blowdowns	Applicability: 100% of pipeline venting during routine maintenance and upsets in production, processing and transmission sector Emission Reduction: 50%	Capital: $100,000/vessel-compressor-station (unit depends on sector) Annual O&M: $2,000/unit	>$100,000 for vessel blowdowns in the production sector $13,576 for compressor blowdowns in the production sector $11.42 for processing $10.63 for transmission
Use portable evacuation compressors	Applicability: 90% of pipeline venting during routine maintenance and upsets in production and transmission sector Emission Reduction: 80%	Capital: $1,400/mile Annual O&M: $10/mile	$1,239 for production sector $12.10 for transmission sector
Install instrument air systems	Applicability: 50%-90% of pneumatic systems in the production and transmission sector Emission Reduction: 100% For pneumatic device vents in the production sector, 6 cases were examined (low-med.-high bleed; intermittent & continuous) For the transmission sector, 9 cases were examined (low-med.-high bleed; continuous, turbine & displacement); applicability is higher for high-bleed devices	Capital: $4,200 Annual O&M: various ($750 for pneumatic device vents in the production sector)	$4.66-$52.56 for pneumatic device vents in the production sector; break-even gas prices are lower for high-bleed devices $3.28-$893 for the transmission sector; break-even gas prices are lower for high-bleed devices
Practice directed inspection and maintenance at processing sites	Applicability: 100% of processing plants Emission Reduction: 33%	Capital: $1,000/plant Annual O&M: $2,000/plant	$2.39

Exhibit III-6: Cost Analysis Data and Assumptions for Partner-Reported Opportunities (continued)

PRO	Applicability and Emission Reductions	Costs	Break-Even Gas Price ($/MMBtu)
Use catalytic converters on engine exhaust	Applicability: 75% of engines and turbines in the transmission sector (including LNG storage) Emission Reduction: 75%	Capital: $3,386/MM HP-Hr ($20,000/engine) Annual O&M: $168/MM HP-Hr ($1,000/engine)	$4.74-$29.53 for compressor exhaust (production) $5.35 for engines (transmission) $94.63 for turbines (transmission) $7.33 for engines (storage) $85.95 for turbines (storage) $10.56 for engines (LNG storage) $479 for turbines (LNG storage)
Practice directed inspection and maintenance at LNG stations	Applicability: 100% of LNG stations in transmission sector Emission Reduction: 60%	Capital: $500/station Annual O&M: $2,065/station	$1.87
Practice directed inspection and maintenance of trans. pipelines	Applicability: 100% of pipeline leaks in the transmission sector Emission Reduction: 60%	Capital: $100 Annual O&M: $150	$527
Use enhanced directed inspection and maintenance at compressor stations	Applicability: 100% of compressor stations in the transmission sector Emission Reduction: 26.5% of emissions from storage compressors, 18.9% of emissions from trans. compressor stations	Capital: $1,000/station Annual O&M: $6,000/station	$0.69 for storage compressor stations $1.11 for transmission compressor stations
Practice directed inspection and maintenance at storage wells	Applicability: 100% of storage wells in the transmission sector Emission Reduction: 33%	Capital: $200/well Annual O&M: $200/well	$18.54
Practice enhanced directed inspection and maintenance at storage wells	Applicability: 100% of storage wells in the transmission sector Emission Reduction: 50%	Capital: $300/well Annual O&M: $400/well	$23.14
Practice enhanced directed inspection and maintenance at gate stations and surface facilities	Applicability: 100% of gate stations and surface facilities in the distribution sector Emission Reduction: 30%-80% of emissions; higher pressure stations have greater emission reductions	Capital: $1,000/station Annual O&M: $1,000/station	$1.01 for M&R >300 psi $2.35 for M&R 100-300 psi $113 for M&R <100 psi
Use electronic metering	Applicability: 100% of trans. co. interconnect M&R stations in the transmission sector; 100% of meter and regulator stations at city gates in distribution sector Emission Reduction: 95%	Capital: $15,000/station Annual O&M: $2,500/station	$4.84 for the transmission sector For the distribution sector: $4.46 for M&R >300 psi $8.40 for M&R 100-300 psi $186 for M&R <100 psi

Exhibit III-6: Cost Analysis Data and Assumptions for Partner-Reported Opportunities (continued)

PRO	Applicability and Emission Reductions	Costs	Break-Even Gas Price ($/MMBtu)
Replace pipeline	Applicability: 100% of cast iron and unprotected steel mains in distribution sector Emission Reduction: 95%	Capital: $1,000,000/mile Annual O&M: $50/mile	$1,229 for cast iron pipeline $2,662 for unprotected steel pipeline
Replace services	Applicability: 100% of unprotected steel services in distribution sector Emission Reduction: 95%	Capital: $250,000/service Annual O&M: $50/service	$43,155 for unprotected steel services

Exhibit III-7: Schedule of Emission Reduction Options for 2010					
Number	**Option**	**Break-Even Gas Price ($/MMBtu)**	**Base Gas Price Type[a]**	**Carbon Equivalent Value ($/TCE)**	**Incremental Emission Reduction (MMTCE/yr)**
1	Practice directed inspection and maintenance at gate stations and surface facilities (Meter/Regulator stations > 300 psi)	$0.69	Citygate	($23.42)	0.23
2	Practice directed inspection and maintenance at gate stations and surface facilities (Reg. > 300 psi)	$0.77	Citygate	($22.72)	<0.01
3	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (Meter/Regulator stations > 300 psi)	$1.01	Citygate	($20.51)	0.56
4	Install fuel gas retrofit systems on compressors to capture otherwise vented fuel when compressors are taken off-line (storage compressor stations)	$0.12	Pipeline	($19.60)	0.42
5	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (Reg. > 300 psi)	$1.13	Citygate	($19.49)	0.33
6	Reduce glycol circulation rates in dehydrators (not applicable to Kimray pumps – this option applies to transmission sector dehydrators without flash tanks)	$0.16	Pipeline	($19.18)	0.01
7	Install fuel gas retrofit systems on compressors to capture otherwise vented fuel when compressors are taken off-line (transmission compressor stations)	$0.17	Pipeline	($19.06)	1.63
8	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to transmission sector, high-bleed, continuous-bleed pneumatic devices)	$0.20	Pipeline	($18.83)	0.59
9	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to transmission sector, medium-bleed, continuous-bleed pneumatic devices)	$0.50	Pipeline	($16.10)	0.39
10	Install fuel gas retrofit systems on compressors to capture otherwise vented fuel when compressors are taken off-line (processing compressor stations)	$0.40	Wellhead	($16.09)	0.43
11	Practice directed inspection and maintenance at storage compressor stations	$0.55	Pipeline	($15.69)	<0.01
12	Reduce glycol circulation rates in dehydrators (not applicable to Kimray pumps – this option applies to production sector dehydrators without flash tanks, with gas assisted pumps)	$0.45	Wellhead	($15.67)	0.28
13	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to production sector, high-bleed, continuous-bleed devices)	$0.49	Wellhead	($15.24)	0.98
14	Practice directed inspection and maintenance at transmission compressor stations	$0.61	Pipeline	($15.05)	<0.01
15	Reduce glycol circulation rates in dehydrators (not applicable to Kimray pumps – this option applies to transmission sector dehydrators with flash tanks)	$0.68	Pipeline	($14.45)	0.73
16	Enhanced Directed Inspection and Maintenance at storage compressor stations	$0.69	Pipeline	($14.40)	0.05
17	Practice directed inspection and maintenance at gate stations and surface facilities (Meter/Regulator stations 100-300 psi)	$1.74	Citygate	($13.90)	0.35
18	Practice directed inspection and maintenance at gate stations and surface facilities (trans. co. interconnect)	$0.75	Pipeline	($13.80)	0.14
19	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (trans. co. interconnect)	$1.10	Pipeline	($10.65)	0.20

Exhibit III-7: Schedule of Emission Reduction Options for 2010 (continued)					
Number	**Option**	**Break-Even Gas Price ($/MMBtu)**	**Base Gas Price Type[a]**	**Carbon Equivalent Value ($/TCE)**	**Incremental Emission Reduction (MMTCE/yr)**
20	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to production sector, high-bleed, intermittent-bleed devices)	$1.00	Wellhead	($10.64)	0.90
21	Practice enhanced directed inspection and maintenance at transmission compressor stations	$1.11	Wellhead	($10.57)	0.04
22	Reduce glycol circulation rates in dehydrators (not applicable to Kimray pumps – this option applies to production sector dehydrators without flash tanks)	$1.04	Wellhead	($10.28)	0.02
23	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to production sector, medium-bleed, continuous-bleed devices)	$1.23	Wellhead	($8.51)	0.65
24	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (Meter/Regulator stations 100-300 psi)	$2.35	Citygate	($8.38)	0.56
25	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to transmission sector, high-bleed, turbine devices)	$1.47	Pipeline	($7.26)	0.04
26	Use reciprocating compressor rod packing (Static-Pac, applies to transmission sector)	$1.74	Pipeline	($4.85)	0.39
27	Use reciprocating compressor rod packing systems (Static-Pac, applies to storage)	$1.81	Pipeline	($4.16)	0.06
28	Practice directed inspection and maintenance at LNG stations	$1.87	Pipeline	($3.62)	0.01
29	Install dry seals on centrifugal compressors (storage sector)	$1.91	Pipeline	($3.27)	0.12
30	Use reciprocating compressor rod packing systems (early replacement of rings and rods on storage sector reciprocating compressors)	$2.09	Pipeline	($1.61)	0.01
31	Install dry seals on reciprocating compressors (transmission sector)	$2.10	Pipeline	($1.55)	0.64
32	Practice directed inspection and maintenance at production and processing sites	$2.39	Pipeline	($0.34)	<0.01
33	Replace higher-bleed pneumatic devices with lower-bleed pneumatic devices (applies to production sector, medium-bleed, intermittent-bleed devices)	$2.50	Wellhead	$3.00	0.68
34	Use reciprocating compressor rod packing systems (early replacement of rings and rods on transmission sector reciprocating compressors)	$2.66	Pipeline	$3.51	0.07
35	Practice directed inspection and maintenance at gate stations and surface facilities (Reg. 100-300 psi)	$4.11	Citygate	$7.65	0.14
36	Install instrument air systems (in place of transmission sector, high-bleed, continuos bleed pneumatic devices)	$3.28	Wellhead	$9.57	0.23
37	Install dry seals on reciprocating compressors (processing sector)	$3.22	Pipeline	$9.16	0.45
38	Install flash tank separators on transmission sector glycol dehydrators	$3.42	Pipeline	$10.47	0.02
39	Use electronic metering (Meter/Regulator stations > 300 psi)	$4.46	Citygate	$10.86	0.10
40	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to transmission sector, low-bleed, continuous-bleed devices)	$3.60	Pipeline	$12.07	0.02

Exhibit III-7: Schedule of Emission Reduction Options for 2010 (continued)					
Number	**Option**	**Break-Even Gas Price ($/MMBtu)**	**Base Gas Price Type[a]**	**Carbon Equivalent Value ($/TCE)**	**Incremental Emission Reduction (MMTCE/yr)**
41	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to transmission sector, medium-bleed, turbine devices)	$3.68	Pipeline	$12.80	0.02
42	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (Reg. 100-300 psi)	$5.54	Citygate	$20.69	0.22
43	Use catalytic converter (applies to compressor exhaust during normal operations in the production and processing sectors)	$4.74	NA	$20.99	<0.01
44	Install instrument air systems (in place of production sector, high-bleed, continuous-bleed pneumatic devices)	$4.66	Wellhead	$22.63	0.35
45	Install instrument air systems (in place of transmission sector, medium-bleed, continuous-bleed pneumatic devices)	$4.79	Pipeline	$22.90	0.14
46	Use electronic monitoring (trans. co. interconnect)	$4.84	Pipeline	$23.33	0.06
47	Use catalytic converter (applies to compressor exhaust during normal operations in the transmission sector)	$5.35	NA	$26.59	<0.01
48	Use catalytic converter (applies to storage engine compressor exhaust during normal operation of transmission sector)	$7.33	NA	$44.58	0.51
49	Install instrument air systems (in place of production sector, high-bleed, intermittent-bleed devices)	$7.21	Wellhead	$45.82	0.32
50	Use electronic monitoring (Meter/Regulator stations 100-300 psi)	$8.40	Citygate	$46.62	0.42
51	Use catalytic converter (applies to fugitive emissions from compressor exhaust in the production and processing sectors)	$8.27	NA	$53.13	0.77
52	Install instrument air systems (in place of production sector, medium-bleed, continuous-bleed pneumatic devices)	$8.39	Wellhead	$56.58	0.24
53	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to production sector, low-bleed, continuous-bleed devices)	$8.89	Wellhead	$61.09	0.02
54	Install flash tank separators on production-sector dehydrators with gas-assisted pumps	$9.49	Wellhead	$66.58	<0.01
55	Install instrument air systems (in place of production sector, high-bleed, turbine devices)	$9.68	Pipeline	$67.43	<0.01
56	Practice directed inspection and maintenance on Gulf of Mexico off-shore platforms	$10.46	Wellhead	$73.04	<0.01
57	Use catalytic converter (applies to LNG compressor exhaust)	$10.56	NA	$73.90	<0.01
58	Use portable evacuation compressors (applies to transmission sector station venting)	$10.63	Pipeline	$74.61	<0.01
59	Use surge vessels (applies to storage sector station venting)	$10.63	Pipeline	$74.61	<0.01
60	Use surge vessels (applies to LNG station venting)	$10.63	Pipeline	$74.61	<0.01
61	Use surge vessels (applies to blowdowns/venting in the production sector)	$11.42	Pipeline	$81.73	1.14
62	Use surge vessels (applies to pipeline venting during routine maintenance in the transmission sector)	$12.10	Pipeline	$87.98	0.18
63	Install instrument air systems (in place of transmission sector, low-bleed, continuous-bleed devices)	$12.34	Pipeline	$92.60	0.78

Exhibit III-7: Schedule of Emission Reduction Options for 2010 (continued)					
Number	Option	Break-Even Gas Price ($/MMBtu)	Base Gas Price Type[a]	Carbon Equivalent Value ($/TCE)	Incremental Emission Reduction (MMTCE/yr)
64	Install instrument air systems (in place of production sector, medium-bleed, intermittent-bleed devices)	$14.77	Wellhead	$115	0.22
65	Practice directed inspection and maintenance (applies to chemical injection pumps)	$15.10	Wellhead	$115	<0.01
66	Practice directed inspection and maintenance (applies to pipeline leaks)	$15.27	Wellhead	$117	<0.01
67	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to transmission sector, high-bleed, displacement devices)	$17.67	Pipeline	$140	0.56
68	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to production sector, low-bleed, intermittent-bleed devices)	$18.00	Wellhead	$144	0.01
69	Practice directed inspection and maintenance at storage wells	$18.54	Pipeline	$147	<0.01
70	Install instrument air systems (in place of transmission sector, medium-bleed, turbine devices)	$20.81	Pipeline	$169	0.04
71	Practice enhanced directed inspection and maintenance at storage wells	$23.14	Pipeline	$188	<0.01
72	Practice directed inspection and maintenance at production sites	$25.88	Wellhead	$213	0.02
73	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to transmission sector, low-bleed, turbine devices)	$26.48	Pipeline	$220	<0.01
74	Install instrument air systems (in place of production sector, low-bleed, continuous-bleed devices)	$27.06	Wellhead	$226	0.04
75	Use catalytic converters on compressor exhaust during normal operations in the production and processing sector	$29.53	NA	$246	<0.01
76	Practice directed inspection and maintenance at surface facilities (applies to Reg. 40-100 psi.)	$40.03	Citygate	$334	0.02
77	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to transmission sector, medium-bleed, displacement devices)	$44.18	Pipeline	$381	<0.01
78	Practice enhanced directed inspection and maintenance at surface facilities (applies to Reg. 40-100 psi.)	$46.78	Citygate	$396	0.01
79	Reduce the recirculation rate on production sector glycol dehydrators with flash tanks with gas assisted pumps	$50.64	Wellhead	$441	<0.01
80	Install instrument air systems (in place of production sector, low-bleed, intermittent-bleed devices)	$52.56	Wellhead	$458	<0.01
81	Install instrument air systems (in place of transmission sector, low-bleed, turbine devices)	$76.41	Pipeline	$674	<0.01
82	Practice directed inspection and maintenance at U.S. gas wells on-shore	$81.14	Wellhead	$716	<0.01
83	Use catalytic converters on compressor exhaust (applies to turbine engines in the storage sector)	$85.95	NA	$760	<0.01
84	Install instrument air systems (in place of transmission sector, high-bleed, displacement devices)	$91.34	Pipeline	$810	<0.01

Exhibit III-7: Schedule of Emission Reduction Options for 2010 (continued)

Number	Option	Break-Even Gas Price ($/MMBtu)	Base Gas Price Type[a]	Carbon Equivalent Value ($/TCE)	Incremental Emission Reduction (MMTCE/yr)
85	Use catalytic converters on compressor exhaust (applies to turbine engines in the transmission sector)	$94.63	NA	$838	<0.01
86	Practice directed inspection and maintenance at gate stations and surface facilities (applies to Meter and Regulator stations < 100 psi)	$96.58	Citygate	$849	<0.01
87	Reduce the recirculation rate on production sector glycol dehydrators with flash tanks without gas assisted pumps	$101	Wellhead	$901	<0.01
88	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (applies to Meter and Regulator stations < 100 psi)	$113	Citygate	$997	<0.01
89	Practice enhanced directed inspection and maintenance at U.S. gas wells on-shore	$126	Wellhead	$1,127	<0.01
90	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (R-vault > 300 psi)	$140	Citygate	$1,247	<0.01
91	Use electronic monitoring (Meter/Regulator stations < 100 psi)	$186	Citygate	$1,664	<0.01
92	Install instrument air systems (in place of transmission sector, medium-bleed, displacement devices)	$225	Pipeline	$2,025	<0.01
93	Install flash tank separators on production-sector glycol dehydrators without gas-assisted pumps	$232	Wellhead	$2,087	<0.01
94	Use plunger lift well (applies to U.S. on-shore wells)	$260	Wellhead	$2,341	<0.01
95	Replace high-bleed pneumatic devices with low-bleed pneumatic devices (applies to transmission sector, low-bleed, displacement devices)	$318	Pipeline	$2,872	<0.01
96	Practice directed inspection and maintenance at gate stations and surface facilities (R-vault > 300 psi)	$320	Citygate	$2,882	<0.01
97	Practice directed inspection and maintenance at gate stations and surface facilities (M&R Farm Taps + Direct Sales)	$320	Pipeline	$2,891	<0.01
98	Practice directed inspection and maintenance at production sites (Eastern on-shore, Appalachia non-associated gas wells)	$415	Wellhead	$3,755	<0.01
99	Practice directed inspection and maintenance at production sites (Eastern on-shore north central non-associated gas wells)	$415	Wellhead	$3,755	<0.01
100	Use catalytic converters on compressor exhaust (applies to LNG compressor emissions from turbine engines)	$479	NA	$4,337	<0.01
101	Practice directed inspection and maintenance at transmission pipelines	$527	Pipeline	$4,771	<0.01
102	Practice enhanced directed inspection and maintenance at production sites (Eastern on-shore, Appalachia non-associated gas wells)	$647	Wellhead	$5,860	<0.01
103	Practice enhanced directed inspection and maintenance at production sites (Eastern on-shore north central non-associated gas wells)	$646	Wellhead	$5,860	<0.01
104	Install instrument air systems (in place of transmission sector, low-bleed, displacement devices)	$893	Pipeline	$8,100	<0.01
105	Practice directed inspection and maintenance at wells and other similar facilities (applies to cast-iron mains)	$1,229	Citygate	$11,155	<0.01

Exhibit III-7: Schedule of Emission Reduction Options for 2010 (continued)

Number	Option	Break-Even Gas Price ($/MMBtu)	Base Gas Price Type[a]	Carbon Equivalent Value ($/TCE)	Incremental Emission Reduction (MMTCE/yr)
106	Use portable evacuation compressors (applies to production sector pipeline blowdowns)	$1,240	Wellhead	$11,253	<0.01
107	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (R-vault 100-300 psi)	$1,248	Citygate	$11,315	<0.01
108	Use plunger-lift wells (applies to Eastern on-shore, Appalachia non-associated gas wells)	$1,330	Wellhead	$12,075	<0.01
109	Use electric starter (applies to compressor starts in the production and processing sector)	$1,536	Wellhead	$13,942	<0.01
110	Practice directed inspection and maintenance at gate stations and surface facilities (R-vault 100-300 psi)	$2,313	Citygate	$21,002	<0.01
111	Practice directed inspection and maintenance at wells and other similar facilities (applies to unprotected steel mains)	$2,662	Citygate	$24,190	<0.01
112	Practice directed inspection and maintenance at gate stations and surface facilities (Reg. < 40 psi)	$3,130	Citygate	$28,434	<0.01
113	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (Reg. < 40 psi)	$3,658	Citygate	$33,238	<0.01
114	Practice directed inspection and maintenance at gate stations and surface facilities (R-vault 40-100 psi)	$4,813	Citygate	$43,735	<0.01
115	Practice enhanced directed inspection and maintenance at gate stations and surface facilities (R-vault 40-100 psi)	$5,625	Citygate	$51,122	<0.01
116	Use surge vessels to capture gas during compressor blowdowns in the production sector	$13,576	Wellhead	$123,433	<0.01
117	Practice directed inspection and maintenance in the transmission sector (replace unprotected steel services)	$43,155	Citygate	$392,423	<0.01
118	Use surge vessels to capture gas during vessel blowdowns in the production sector	$656,849	Wellhead	$5,973,306	<0.01

[a] Wellhead = $2.17/MMBtu, pipeline = $2.27/MMBtu, citygate = $3.27/MMBtu.
All prices are in real 1996 dollars.

Reference

EPA/GRI. 1996. *Methane Emissions from the Natural Gas Industry, Volume 1: Executive Summary,* Prepared by Harrison, M., T. Shires, J. Wessels, and R. Cowgill, eds., Radian International LLC for National Risk Management Research Laboratory, Air Pollution Prevention and Control Division, Research Triangle Park, NC, EPA-600-R-96-080a.

Appendix IV: Supporting Material for the Analysis of Coal Mining

This appendix presents the coal mine data that EPA used to develop methane emission forecasts and to estimate methane emission reduction costs. The exhibits are described below:

- **Exhibit IV-1: Historical and Projected Coal Production.** This exhibit details historic and projected coal production data for surface and underground mines. These data underlie projections of the quantity of methane liberated from coalbeds. Historical data are shown for the period 1990-1997. Projected data are provided for the years 2000, 2005, 2010, 2015, and 2020.
- **Exhibit IV-2: Coal Mine Methane Liberation Estimates by Year.** The estimates of methane liberated from coal mining in 1997 are presented in this exhibit. Projections of methane liberated are also provided, based on the production data in Exhibit IV-1. These estimates are the basis for determining achievable and cost-effective emission reductions.
- **Exhibit IV-3: Coal Basin Recovery Efficiencies by Year.** This exhibit summarizes the methane recovery efficiencies by coal basin and by year. Methane recovery efficiencies vary by coal basin. In addition, EPA assumes that the technology to recover methane will improve over time, leading to increased methane recovery.
- **Exhibit IV-4: Cost Data and Assumptions Used in the Coal Mine Analysis.** The assumptions and data underlying the cost analysis of methane recovery and use techniques are summarized in this exhibit. Data are arranged by type of cost (well, compression, processing, etc.) and option number.
- **Exhibit IV-5: Schedule of Emission Reduction Options for 2010.** This exhibit provides a schedule of emission reduction data by option and individual mine for 2010. Data include annual coal production, liberated methane, projected "break-even" gas price, the value of carbon equivalent ($/TCE), and the cumulative amount of emissions reduced.

Exhibit IV-1: Historical and Projected Coal Production (Million Short Tons)													
	Historical								Projected				
	1990	1991	1992	1993	1994	1995	1996	1997	2000	2005	2010	2015	2020
Underground	425	407	407	351	399	396	410	421	427	482	510	537	552
Surface	605	589	590	594	634	636	654	669	718	725	756	789	824
Total Production	1,029	996	998	945	1,034	1,033	1,064	1,090	1,145	1,207	1,265	1,326	1,376
Underground (% of Total)	41%	41%	41%	37%	39%	38%	39%	39%	37%	40%	40%	41%	40%
Surface (% of Total)	59%	59%	59%	63%	61%	62%	61%	61%	63%	60%	60%	59%	60%

Source: EIA, 1998a and 1998b.

Exhibit IV-2: Coal Mine Methane Liberation Estimates by Year			
Year	Total Methane Liberated (MMcf)	Methane Liberated from Underground Mining (MMcf)	Underground Mining (% of Total)
1997	212,312	153,203	72.2
2000	217,142	155,570	71.6
2005	241,501	175,490	72.7
2010	254,966	185,614	72.8
2015	268,377	195,592	72.9
2020	276,454	201,091	72.7

MMcf = million cubic feet

Source: Projections based on EPA, 1999a, and EIA, 1998b.

Exhibit IV-3: Coal Basin Recovery Efficiencies by Year						
Basin	1997	2000	2005	2010	2015	2020
Warrior	45.0%	45.0%	47.5%	50.0%	52.5%	55.0%
Illinois	50.0%	50.0%	52.5%	55.0%	57.5%	60.0%
Northern Appalachian	55.0%	55.0%	57.5%	60.0%	62.5%	65.0%
Central Appalachian	55.0%	55.0%	57.5%	60.0%	62.5%	65.0%
Western	50.0%	50.0%	52.5%	55.0%	57.5%	60.0%

Source: Experience with existing coal mine methane projects, and EPA, 1997b.

Exhibit IV-4: Cost Data and Assumptions Used in the Coal Mine Analysis		
Cost Item	**Number or Size of Units Needed**	**Cost Per Unit**
	Costs for Wells	
Vertical Well	Option 1: 1 well for every 250,000 tons of coal mined	$150,000/well
	Option 2: 1 well for every 1 million tons of coal mined [a]	
Gob Wells	Option 1: 1 well for every 500,000 tons of coal mined	$30,000/well
	Option 2: 1 well for every 1 million tons of coal mined [a]	
In-Mine Boreholes	Option 1: 1 well for every 500,000 tons of coal mined	$75,000/well
	Option 2: 1 well for every 1 million tons of coal mined [a]	
Well Water Disposal Costs (Vertical Wells Only)	1 barrel of water is produced per Mcf (thousand cubic feet) of gas produced	$0.50 per barrel per year
	Compression Costs	
Wellhead Compressor	1 per well at 200 HP/MMcfd	Capital costs: $600/HP; O&M costs: $20/HP
Satellite Compressor	1 per project at 150 HP/MMcfd	
Sales Compressor	1 per project at 150 HP/MMcfd	
Gathering Lines from Wellhead to Satellite	Length of gathering lines from each well to satellite = 2000 ft	$10/ft
Gathering Lines from Satellite to Point of End-Use	Length of gathering lines from satellite to point of end-use = 26,400 ft (5 miles)	$15/ft
Cost of Moving Gathering Lines		$5/ft per year
	Gas Processing Costs	
Dehydrator	1 per project	Capital Cost: $40,000; O&M cost: $3,000
Gas Enrichment (Fixed Capital Cost) $/project	Required for Option 2 only	$1,888,500
Gas Enrichment (Variable Capital Cost) $/MMCFD	Required for Option 2 only	$526,000
Gas Enrichment (Fixed Annual Operating Cost) $/year	Required for Option 2 only	$132,000
Gas Enrichment (Operating Cost Based on Maximum Gas Production) $/MMCFD	Required for Option 2 only	$37,167
	Oxidizer Costs	
Oxidizer (Without Electricity Generation)	Option 3 only	Capital Cost: $6.2 million; O&M costs: $541,740[b]

[a] Option 1 is degasification and pipeline injection. Option 2 is degasification and pipeline injection incremental to Option 1. Option 3 is catalytic oxidation.

[b] Costs are for a system capable of handling 211,860 scf/min of ventilation air at 0.5% methane; for each mine, the cost was scaled based on the mine's flow rate relative to 211,860 scf/min.

Source: EPA 1997a, b, and c; CANMET, 1998.

Exhibit IV-5: Schedule of Emission Reductions for 2010						
Mine Name	Option[a]	Coal Production (MM short tons/yr)	Total Methane Liberated (MMcf/yr)	Break-Even Cost ($/MMBtu)	Additional Value of Methane ($/TCE)	Cumulative Emissions Avoided (MMTCE/yr)
VP No. 8	1	1.60	13,237	0.47	(18.69)	0.87
VP No. 3	1	2.69	11,919	0.52	(18.23)	1.66
Blue Creek No. 5	1	1.44	7,352	0.54	(18.05)	2.06
Blue Creek No. 7	1	3.17	13,953	0.54	(18.05)	2.83
Buchanan No. 1	1	5.26	18,523	0.54	(18.05)	4.05
Blue Creek No. 4	1	2.75	10,296	0.57	(17.78)	4.62
Blue Creek No. 3	1	2.78	8,736	0.60	(17.51)	5.10
Pinnacle No.50 (Gary)	1	6.46	7,135	0.84	(15.32)	5.57
Oak Grove	1	3.17	4,460	0.85	(15.23)	5.82
Blacksville No. 2	1	4.18	6,281	1.13	(12.69)	6.23
VP No. 8	2	1.60	13,237	1.41	(10.14)	6.52
Sanborn Creek	1	1.94	3,121	1.54	(8.96)	6.71
Blue Creek No. 7	2	3.17	13,953	1.60	(8.41)	7.02
Buchanan No. 1	2	5.26	18,523	1.63	(8.14)	7.42
VP No. 3	2	2.69	11,919	1.64	(8.05)	7.69
Blue Creek No. 4	2	2.75	10,296	1.77	(6.87)	7.91
Blue Creek No. 5	2	1.44	7,352	1.79	(6.68)	8.07
Enlow Fork	1	10.15	7,135	1.88	(5.87)	8.55
Shoal Creek	1	4.86	1,976	1.90	(5.68)	8.65
Emerald No. 1	1	5.85	4,091	1.91	(5.59)	8.92
Blue Creek No. 3	2	2.78	8,736	1.94	(5.32)	9.12
Cumberland	1	7.71	5,004	2.01	(4.68)	9.45
Maple Meadow	1	1.28	1,370	2.03	(4.50)	9.54
Federal No. 2	1	5.32	3,347	2.09	(3.96)	9.76
Bailey	1	9.11	5,093	2.26	(2.41)	10.09
Loveridge No. 22	1	5.82	2,992	2.45	(0.68)	10.29
Mine 84	1	5.80	4,028	2.66	1.23	10.56
Soldier Canyon	1	1.39	1,164	2.66	1.23	10.63
Dilworth	1	5.38	2,506	2.67	1.32	10.79
Blacksville No. 2	2	4.18	6,281	2.77	2.23	10.93
Roadside North Portal	1	0.52	483	2.84	2.86	10.96
Sentinel Mine	1	1.39	973	2.86	3.05	11.02
Galatia Mine No. 56-1	1	6.03	4,094	2.92	3.59	11.27
Robinson Run No. 95	1	5.79	2,272	3.09	5.14	11.42
Oak Grove	2	3.17	4,460	3.11	5.32	11.52
Pinnacle No.50 (Gary)	2	6.46	7,135	3.14	5.59	11.68
Sanborn Creek	2	1.94	3,121	3.33	7.32	11.74
West Elk Mine	1	6.93	3,975	3.37	7.68	11.99
McClure No. 2 Mine	1	0.44	306	3.56	9.41	12.01
Bowie #1 Mine	1	0.92	506	4.01	13.50	12.04
Tanoma	1	0.65	350	4.03	13.69	12.06
Enlow Fork	2	10.15	7,135	4.11	14.41	12.22
Aberdeen	1	2.27	1,077	4.18	15.05	12.28
Boone No. 1	1	1.03	586	4.19	15.14	12.31
Bay Beck Mine	1	1.19	552	4.20	15.23	12.35

Exhibit IV-5: Schedule of Emission Reductions for 2010 (continued)						
Mine Name	**Option[a]**	**Coal Production (MM short tons/yr)**	**Total Methane Liberated (MMcf/yr)**	**Break-Even Cost ($/MMBtu)**	**Additional Value of Methane ($/TCE)**	**Cumulative Emissions Avoided (MMTCE/yr)**
Emerald No. 1	2	5.85	4,091	4.54	18.32	12.44
Brushy Creek Mine	1	1.07	501	4.56	18.51	12.47
Cumberland	2	7.71	5,004	4.57	18.60	12.58
Mine 84	2	5.80	4,028	4.58	18.69	12.67
McElroy	1	6.48	2,415	4.59	18.78	12.83
Galatia Mine No. 56-1	2	6.03	4,094	4.63	19.14	12.92
Shoemaker	1	5.79	2,111	4.70	19.78	13.06
North River	1	2.41	1,035	4.98	22.33	13.11
Bailey	2	9.11	5,093	5.03	22.78	13.23
Federal No. 2	2	5.32	3,347	5.06	23.05	13.30
Pattiki Mine	1	2.43	918	5.13	23.69	13.36
West Elk Mine	2	6.93	3,975	5.16	23.96	13.44
Wabash Mine	1	1.92	711	5.32	25.42	13.49
Urling No. 1 Mine	1	0.73	271	5.50	27.05	13.50
Maple Meadow	2	1.28	1,370	5.55	27.51	13.53
Maple Creek	1	2.27	711	5.63	28.24	13.58
All Mines	3			5.79	29.70	20.00

[a] Option 1 is degasification and pipeline injection. Option 2 is degasification and pipeline injection incremental to Option 1. Option 3 is catalytic oxidation.

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Appendix V: Supporting Material for the Analysis of Livestock Manure Management

In this appendix, EPA presents additional information to further explain selected components of the emission and emission reduction analysis for methane from livestock manure, presented in Chapter 5. These areas are: (1) the emission estimation methodology, (2) the specific project costs for anaerobic digester based methane recovery and utilization systems, and (3) uncertainties.

V.I Methodology for Estimating Methane Emissions from Livestock Manure Management

EPA uses the following approach to estimate methane emissions from livestock manure. This approach calculates emissions based on the type and quantity of the manure, the characteristics of the manure management system, and the climatic conditions in which the manure decomposes. As livestock farms often use several systems to manage manure and each system usually has a different potential for generating methane, several calculations may be necessary.

The methane emission relationship is shown below:

$$CH_4 = \sum_{i}^{\text{states}} \sum_{j}^{\text{animal}} \sum_{k}^{\text{systems}} \text{Manure}_{ij} \cdot MF_{ijk} \cdot VS_{ij} \cdot B_{oj} \cdot MCF_{ik}$$

where CH_4 = Methane generated (ft^3/day)

Manure_{ij} = Total manure produced by animal type *j* in state *i* (lbs/day)

MF_{ijk} = Percent of manure managed by system *k* for animal type *j* in state *i*

VS_{ij} = Percent of manure that is volatile solids for animal type *j* in state *i*

B_{oj} = Maximum methane potential of manure for animal *j* (ft^3/lb volatile solids)

MCF_{ik} = Methane conversion factor for system *k* in state *i*

Each factor in the emission analysis is determined as follows:

Manure Production. The amount of manure generated depends on the type, number, and size of the animals. The U.S. Department of Agriculture (USDA) publishes detailed state-level population data for each year. These livestock data are used with published manure production characteristics (Exhibit V-1) to determine manure generation for each livestock category.

Manure Management Systems. The manner in which manure is managed determines whether it generates methane. Manure management use for swine and dairy cattle are determined using the latest livestock population survey conducted by the U.S. Department of Commerce (USDC, 1995). The census survey, conducted for 1992, includes population data by farm size. This distribution is used to determine manure management system usage -- larger farms (500 or more dairy cows, 1,000 or more swine) were assumed to use liquid systems, and smaller farms are assumed to use dry systems. For all other animal types, manure management system use figures published by EPA (Safely, et al., 1992) are used. These data, collected from livestock manure management experts in each state, estimate the fraction of manure managed using the most common manure management systems.

Manure Characteristics. EPA documents livestock and manure characteristics in Safely, et al., (1992), which are industry standards in the design of livestock specific manure management systems. The methane potential for manure (B_o) values are based on laboratory measurements where the maximum amount of methane that can be generated by manure is measured. Volatile solids (VS) production values are published annually by the American Society of Agricultural Engineers (ASAE, 1995). Exhibit V-1 presents values for dairy cattle and swine.

Methane Conversion Factors. The methane conversion factor (MCF) data for each of the manure systems in the different climates are based on field and laboratory measurements. The data for lagoons and ponds are based on measurements at dairy and hog lagoons conducted continuously over several years. [1] The MCF data for the other systems are based on laboratory measurements conducted at Oregon State University (Hashimoto and Steed, 1992). Exhibit V-2 lists typical values for dairy and swine manure and the most common manure management systems. A typical large dairy will manage up to half the manure using liquid systems, whereas a typical large swine farm will manage almost all the manure using liquid systems.

Exhibit V-1: Manure Characteristics

	Weight (lbs)	Manure (lbs/day)	VS%	B_o
Dairy				
Milk cow	1,400	112	7	3.8
Dry cow	1,300	107	11	3.8
Heifers	900	77	6	3.8
Calves	500	43	6	3.8
Swine				
Sow	400	24	9	5.8
Nursery	30	3.2	8	7.5
Grower	70	4.4	9	7.5
Finisher	180	11.4	9	7.5

Source: Safley, et al., 1992.

Exhibit V-2: Methane Conversion Factors (MCF)

	Warm 30 C	Temperate 20 C	Cool 10 C
Liquid/Slurry	.65	.35	.10
Pits < 30 days retention	0.1	0.2	0.4
Pits > 30 days retention	0.2	0.4	0.8
Tanks	0.2	0.4	0.8
Pasture, Range	.02	.015	.01
Drylots, Corrals	.05	.015	.01
Daily Spread	.01	.005	.0001
		Average Annual MCF	
Anaerobic Lagoons		.90	
Litter		.10	
Deep Pit Stacking		.05	

Source: EPA, 1993; Hashimoto and Steed, 1992.

[1] Over the course of several years, Dr. Lawson Safley at North Carolina State University monitored the amount of methane generated by a covered lagoon used to manage dairy manure. In addition to monitoring methane, Dr. Safley recorded the air temperature and lagoon temperature and the characteristics of the wastewater entering and leaving the lagoon. These data were then used to create a model called Lagmet that estimates methane generation based on wastewater characteristics, temperature, and lagoon design. In addition to Dr. Safley's measurements, additional data were collected by Hashimoto and Steed (1992) from lagoons in other parts of the country.

V.2 Anaerobic Digester Technology System Costs

Emission reductions were determined by analyzing the methane recovery opportunities at dairy and swine farms. Methane recovery system costs for each Anaerobic Digestion Technology (ADT) from EPA (1997a) are displayed in Exhibits V-3 through V-5. All costs are in 1996 US$.

Exhibit V-3: Livestock Manure Methane Recovery and Utilization Costs - Covered Anaerobic Digester

Component Unit Costs			
Lagoon Costs		**Utilization Equipment Costs**	
Component	Cost	Component	Cost
Excavation ($/yd)	$1.75	Electricity gen w/heat rec ($/kW cap)	$750
Attachment wall ($/yd)	$200	Electricity gen O&M ($/kWh produced)	$0.015
Pipe and influent box	$1,700	Electricity gen building ($/unit)	$10,000
Soil test	$1,200	Switch gear ($/unit)	$5,000
Foam trap	$75	Boiler cost ($/unit)	$10,000
Very high durability cover material ($/ft^2)	$0.85	Boiler shed ($/unit)	$3,500
Cover install labor ($/ft^2)	$0.35	Chiller ($/ton cap)	$1,050
		Flare ($/unit)	$1,500
Gas Handling Costs		**Labor and Services Costs**	
Component	Cost	Component	Cost
Gas filter ($/unit)	$700	Labor crew ($/hr)	$150
Gas pump ($/unit)	$900	Engineering ($/job)	$25,000
Gas meter ($/unit)	$800	Backhoe ($/hr)	$60
Gas pressure regulator ($/unit)	$500		
J-trap ($/unit)	$100	**Pipe Costs**	
Manhole ($/unit)	$300	Component	Cost
Manometer ($/unit)	$500	2 in. Diameter PVC pipe ($/ft)	$1.00
		3 in. Diameter PVC pipe ($/ft)	$1.50
		4 in. Diameter PVC pipe ($/ft)	$2.00
		6 in. Diameter PVC pipe ($/ft)	$2.25
		7 in. Diameter PVC pipe ($/ft)	$4.00

Typical Project Costs (including labor)			
500 cow dairy (CA)		**1000 sow swine farm (NC)**	
Lagoon Costs	$42,579	Lagoon Costs	$14,400
Gas Handling Costs	$2,380	Gas Handling Costs	$2,380
Piping Costs	$3,306	Piping Costs	$3,306
Utilization Equipment Costs	$57,306	Utilization Equipment Costs	$27,925
Engineering Costs	$25,000	Engineering Costs	$25,000
TOTAL	**$135,571**	**TOTAL**	**$73,011**

Source: EPA, 1997a.

Exhibit V-4: Livestock Manure Methane Recovery and Utilization Costs: Plug Flow Digester

Plug-Flow Digester Component Unit Costs

Plug Flow Digester Costs		**Utilization Equipment Costs**	
Component	Cost	Component	Cost
Excavation ($/yd)	$1.75	Electricity gen ($/kW cap)*	$750
Concrete tank & foundation ($/yd)	$225	Electricity gen O&M ($/kWh produced)	$0.02
Curb & grade beam ($/yd)	$6	Electricity gen building ($/unit)	$10,000
Pipe and influent box ($)	$800	Switch gear ($/unit)	$5,000
Digester insulation ($/panel)	$28	Flare ($/unit)	$1,500
Very high durability cover material ($/ft^2)	$0.85		
Cover install labor ($/ft^2)	$0.35	* Includes heat recovery	
Foam liner protector ($/ft)	$1.25		
Separator ($)	$50,000		
Hot Water Transmission Costs		**Labor and Services Costs**	
Components		Component	Cost
Trench/sand/liner ($/ft)	$2.3	Labor crew ($/hr)	$150
Manometer ($)	$500	Engineering ($/job)	$25,000
Hot water pipe ($/ft)	$3.5	Backhoe ($/hr)	$60
Gas Handling Costs		**Pipe Costs**	
Components	Cost	Component	Cost
Gas filter ($/unit)	$700	2 in. Diameter PVC pipe ($/ft)	$1.00
Gas pump ($/unit)	$900	3 in. Diameter PVC pipe ($/ft)	$1.50
Gas meter ($/unit)	$800	4 in. Diameter PVC pipe ($/ft)	$2.00
Gas pressure regulator ($/unit)	$500	6 in. Diameter PVC pipe ($/ft)	$2.25
J-trap ($/unit)	$100	7 in. Diameter PVC pipe ($/ft)	$4.00
Manhole ($/unit)	$300		
Manometer ($/unit)	$500		

Typical Project Costs for a 500 Cow Dairy - California (including labor)

Digester Costs	$58,721
Hot Water & Gas Handling Costs	$2,804
Piping Costs	$1,163
Solid Separator	$50,000
Utilization Equipment Costs	$70,869
Engineering Costs	$25,000
TOTAL	**$198,557**

Source: EPA, 1997a.

Exhibit V-5: Livestock Manure Methane Recovery and Utilization Costs: Complete Mix Digester

Complete-Mix Digester Component Unit Costs

Complete Mix Digester Costs		**Utilization Equipment Costs**	
Component	Cost	Component	Cost
Excavation ($/yd)	$1.75	Electricity gen ($/kW cap)*	$750
Concrete tank & foundation ($/yd)	$225	Electricity gen O&M ($/kWh produced)	$0.02
Curb & grade beam ($/ft)	$6	Electricity gen building ($/unit)	$10,000
Pipe and influent box ($)	$1,700	Switch gear ($/unit)	$5,000
Pipe/fit/rack/labor ($/ft^3 digester volume)	$.10	Flare ($/unit)	$1,500
Very high durability cover material ($/ft^2)	$0.85		
Cover install labor ($/ft^2)	$0.35	* Includes heat recovery	

Hot Water Transmission Costs		**Labor and Services Costs**	
Component		Component	Cost
Trench/sand/liner ($/ft)	$2.3	Labor crew ($/hr)	$150
Manometer ($)	$500	Engineering ($/job)	$25,000
Hot water pipe ($/ft)	$3.5	Backhoe ($/hr)	$60
Gas Handling Costs		**Pipe Costs**	
Component	Cost	Component	Cost
Gas filter ($/unit)	$700	2 in. Diameter PVC pipe ($/ft)	$1.00
Gas pump ($/unit)	$900	3 in. Diameter PVC pipe ($/ft)	$1.50
Gas meter ($/unit)	$800	4 in. Diameter PVC pipe ($/ft)	$2.00
Gas pressure regulator ($/unit)	$500	6 in. Diameter PVC pipe ($/ft)	$2.25
J-trap ($/unit)	$100	7 in. Diameter PVC pipe ($/ft)	$4.00
Manhole ($/unit)	$300		
Manometer ($/unit)	$500		

Typical Project Costs for a 1,000 Head Swine Farm –North Carolina (including labor)

Complete Mix Digester Costs	$22,137
Gas Handling Costs	$2,804
Piping Costs	$1,163
Utilization Equipment Costs	$36,000
Engineering Costs	$25,000
TOTAL	**$87,104**

Source: EPA, 1997a.

V.3 Uncertainty

This section summarizes uncertainties in the emission reduction analysis. Exhibit V-6 displays the uncertainty level as well as the basis for the uncertainty.

Exhibit V-6: Summary of Emission Reduction Uncertainties

Uncertainty	Basis
Livestock Demographics	Latest existing farm-size distribution data is for 1992. Shifts in both dairy and swine populations towards larger facilities is not reflected.
Effectiveness of Methane Recovery Technologies	These technologies have been applied on dairy and swine farms throughout the country for over two decades.
Value of Methane Recovered	
Facility Energy Costs	Energy rates vary by utility and within each state. Forecasts assume constant costs. Restructuring of utility industry may affect rates.
Non-Monetary Benefits (odor, pollution, etc.)	Value is difficult to quantify. Recent projects at swine farms have been initiated primarily to reduce odor.
Methane Recovery Costs	
Project Development/ Construction Costs	Information based on current projects and industry experts. Site-specific factors can influence costs of individual projects.

V.4 References

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Appendix VI: Supporting Material for the Analysis of Enteric Fermentation

This appendix provides additional information regarding the methods used to estimate emissions from livestock enteric fermentation. Methane emissions associated with enteric fermentation from the U.S. population of cattle, sheep, goats, pigs and horses are estimated. The estimates primarily depend on the livestock population and associated emission factors.

The first section describes the livestock population and presents population data used to estimate 1997 emissions from livestock enteric fermentation. The second section presents and describes the emission factors used for the 1997 emission estimates.

VI.1 Population Data

This section provides the population data used to estimate 1997 methane emissions from livestock enteric fermentation. In addition, this section elaborates on the three main beef industry sectors. The U.S. Department of Agriculture (USDA) collects population data at the state level annually. Population data from 1997 for cattle, sheep, goats and pigs are presented in Exhibit VI-1. Cattle population data are broken down beyond the national level to account for variation in management practices and type of feed throughout the country. Because these factors affect methane emissions and are highly variable, breaking the population down into groups improves the accuracy of the analysis. The animal groups are presented and described in Exhibit VI-2.

EPA divides the beef population into three main categories to account for different animal and feed characteristics. The three main beef sectors are the cow-calf, stocker (backgrounding), and feedlot sectors.

- **Cow-Calf Sector**. In the cow-calf sector, calves feed on their mother's milk for two to three months, after which they start a diet of milk and forage. Calves are simulated to start producing methane at 165 days, and are weaned at 205 days.
- **Stocker Sector.** Following the cow-calf sector, most calves enter the stocker sector, during which they consume primarily forages. Animals are placed in the stocker phase to increase their weight be-

Exhibit VI-1: Animal Population Sizes for 1997

Animal Type	Population (000)	Animal Type	Population (000)
Mature Dairy Cows	9,304	Yearlings	22,767
Dairy Replacement Heifers (0-12 Months)	3,828	Bulls	2,320
Dairy Replacement Heifers (12-24 Months)	3,828	Sheep	7,607
Mature Beef Cows	34,486	Goats	2,295
Beef Replacement Heifers (0-12 Months)	5,678	Horses	6,150
Beef Replacement Heifers (12-24 Months)	5,678	Pigs	58,671
Weanlings	5,692		

Source: FAO, 1998; USDA, 1997 and 1998a-d.

fore being placed in the feedlot. Animals going through stockering are called Yearlings (see Exhibit VI-2).

➢ **Feedlot Sector.** Approximately 20 percent of the calves from the cow-calf sector enter the feedlot sector directly after they are weaned at about 205 days. These animals are called Weanlings (see Exhibit VI-2). The remaining calves (Yearlings) go through the stocker sector before entering the feedlot. Once in the feedlot, animals consume a high energy, high protein diet until they reach slaughter weight.

Exhibit VI-2: Animal Groups and Animal Characteristics

Animal Type	Initial Weight (kg)	Final Weight (kg)	Initial Age (days)	Final Age (days)	Other Characteristics
Dairy Replacement Heifers 0-12 Months	170	285	165	365	Calves feed on milk for first several months, a mixture of milk and forage from 60-90 days, and are weaned at 205 days, after which they consume all forage.
Dairy Replacement Heifers 12-24 Months	285	460	365	730	Dairy replacements are simulated to give birth at about 24 months, and to increase in body weight to the size of a Holstein cow, i.e., 550 kg.
Beef Replacement Heifers 0-12 Months	165	270	165	365	Calves feed on milk for first several months, a mixture of milk and forage from 60-90 days, and are weaned at 205 days, after which they consume all forage.
Beef Replacement Heifers 12-24 Months	270	390	365	730	Beef replacements are simulated to give birth at about 24 months.
Yearling System	170	480	165	565	Yearling system steers and heifers enter and leave the backgrounding phase at 165 and 425 days of age, respectively. Subsequently, they spend 140 days in the feedlot.
Weanling System	170	480	165	422	Weanling system steers and heifers enter the feedlot at 165 days, and are simulated to stay in the feedlot for 422 days.
Dairy Cows	550	550	365	730	Mature dairy cows produce milk for 305 days, followed by a 60 day dry period. They are simulated to give birth at end of 60 day dry period.
Beef Cows	450	450	365	730	Mature beef cows produce milk for 205 days, and produce less milk than mature dairy cows.
Beef Bulls	650	650	365	730	Beef bulls are simulated to lose weight during the 90 day breeding period, and to gain weight during the rest of the year.

Note: Dairy bulls are not included in the inventory because the dairy bull population is small.

Source: EPA, 1993a.

VI.2 Emission Factors

EPA uses emission factors specific to each animal type. These factors are based on research data and expert opinion. This section presents the factors for cattle and sheep, goats, pigs, and horses.

Cattle. The emission factors for beef and dairy cattle are presented in Exhibit VI-3 and Exhibit VI-4, respectively. Emission factors are developed using the model by Baldwin, et al. (1987a-b).

EPA uses diets in the model developed by Baldwin, et al. (1987 a-b) to estimate emissions from cattle. To account for differences in diets throughout the U.S., thirty-two different diets are defined by EPA (1993a). Fourteen diets are defined for dairy cattle, including six for dairy cows and four each for replacement heifers 0-12 months and 12-24 months. The eighteen beef cattle diets include three each for beef cows, replacement heifers 0-12 months, Weanling System heifers and steers, and Yearling System heifers and steers. Four diets are defined for beef replacement heifers 12-24 months, and two diets are defined for beef bulls. EPA (1993a) provides a breakdown of the diets by region.

Exhibit VI-3: Emission Factors for Beef Cattle (kg/hd/yr)

Animal	North Atlantic	South Atlantic	North Central	South Central	West
Replacement Heifers (0-12) Months	19.2	22.7	20.4	23.6	22.7
Replacement Heifers (0-24) Months	63.8	67.5	60.8	67.7	64.8
Mature Cows	61.5	70.0	59.5	70.9	69.1
Weanlings	--	--	22.6	24.0	23.5
Yearlings	--	--	47.0	47.6	47.6
Bulls	--	--	--	--	100.0

kg/hd/yr = kilograms per head per year

Source: EPA, 1993a.

Exhibit VI-4: Emission Factors for Dairy Cattle (kg/hd/yr)

Animal	North Atlantic	South Atlantic	North Central	South Central	West
Replacement Heifers (0-12) Months	19.5	20.5	18.9	20.3	20.7
Replacement Heifers (0-24) Months	58.4	58.7	57.4	61.7	61.2
Mature Cows	125.8	136.5	111.8	120.5	139.4

Note: Emission factors for mature dairy cows change annually according to milk production. Mature dairy cow emission factors are for 1997.

Source: EPA, 1993a.

With the exception of mature dairy cows, the emission factors for cattle have remained unchanged since those reported by EPA in 1993 (EPA, 1993a). Methane emission estimates from dairy cattle are adjusted annually to reflect increases in milk production per cow. Emission estimates are altered according to milk production levels because milk production is related to feed intake, which influences methane production.

Sheep, Goats, Pigs, and Horses. Average emission factor estimates are from Crutzen, et al. (1986), who developed emission factors for developed and developing countries. These emission factors are shown in Exhibit VI-5. For this analysis, emission factors for developing countries are used. Typical animal size, feed intakes, and feed characteristics are considered in the estimates. Emission factors have not been developed for the U.S., specifically, because emissions from non-cattle are small relative to emissions from cattle.

Exhibit VI-5: Emission Factors for Sheep, Goats, Pigs, and Horses (kg/hd/yr)

Animal	Emission Factor
Sheep	8.0
Goats	5.0
Pigs	1.5
Horses	18.0

Source: Crutzen, et al., 1986; EPA, 1993a.

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